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Executive Summary

Federal tax policy provides a broad array of incentives for energy investment. I review those policies and construct estimates of marginal effective tax rates for different energy capital investments as of 2007. Effective tax rates vary widely across investment classes. I then consider investment in wind generation capital and regress investment against a user cost of capital measure along with other controls. I find that wind investment is strongly responsive to changes in tax policy. On the basis of the coefficient estimates, the elasticity of investment with respect to the user cost of capital is in the range of −1 to −2. I also demonstrate that the federal production tax credit plays a key role in driving wind investment over the past 18 years.

I. Introduction

Investment in new energy capital infrastructure is much in the news these days. The American Recovery and Reinvestment Act of 2009 included over $60 billion in funds for clean energy investments. If passed, the American Clean Energy and Security Act of 2009 would implement a cap and trade system to reduce greenhouse gas emissions—nearly 80% of which are associated with energy production or consumption—and implement a new mandate for renewable electricity with 20% to be provided by renewable sources by 2020.[1] New capital investments are critical to the administration's goals of reducing our reliance on petroleum products and reducing greenhouse gas emissions.

The tax code has historically been a significant policy instrument for shaping energy decisions in the marketplace. Much attention has been paid to the magnitude of federal dollars supporting different energy sources. A recent study by the U.S. Energy Information Administration (EIA 2008a), for example, estimates that roughly two-thirds of tax subsidies for energy production were received by producers of fossil fuels

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in 1999 in contrast to one-third for producers of renewable energy. By 2007 the share going to renewable producers had risen to nearly 40% and the share going to fossil fuel producers had fallen to less than 50%.

While much is known about the number and dollar value of tax benefits, surprisingly little is known about how the tax code affects investment in energy capital. This paper seeks to fill that gap. I begin by reviewing key energy tax code provisions in Section II. In Section III, I construct measures of the effective tax rate on various forms of energy capital. Section IV provides an empirical analysis of investment in wind power taking tax considerations into account. Section V presents conclusions.

Before I turn to these issues, it may be useful to provide a bit of an overview on U.S. energy production and our energy capital infrastructure. Figure 1 shows the distribution of domestic energy production by fuel source for 2007. Domestic production of energy totaled 71.5 quadrillion British thermal units (or quads) in that year. Roughly one-third of the energy we produce is coal: the United States is second only to China in world coal production. Natural gas accounts for just over one-quarter and crude oil (including natural gas plant liquids) just under one-fifth. Solar, geothermal, and wind account for just 1% of U.S. energy production.[2]

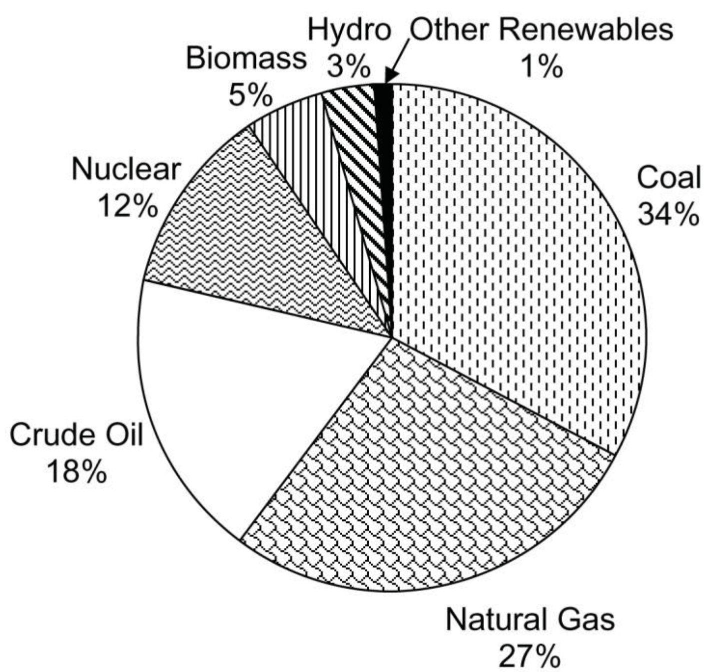

Fig. 1. U.S. primary energy production. Source: EIA (2009a)

Table 1 provides some numbers on the value of fixed assets related to energy production in 2007. The infrastructure related to energy production amounted to nearly $2.9 trillion. This amounts to 12% of the value of the net stock of nonresidential fixed assets in that year.[3] The bulk of energy-related assets are structures—electrical generation facilities and mining exploration, shafts, and wells.

II. Review of Key Energy Tax Code Provisions

Energy is subject to taxes and at the same time is the beneficiary of various tax deductions and credits at both the federal and state levels. In this section, I review the current treatment of energy in the tax code.[4]

A. Federal Tax Provisions

To begin, income earned in the production or distribution of energy is subject to the U.S. income tax. Most energy-related income is taxed through the corporate income tax with a top federal marginal tax rate of 35%. Table 2 indicates the share of assets taxed through the corporate income tax in various energy-related industries.[5] For the mining, utilities, and petroleum and coal manufacturing sectors, the vast bulk of assets are subject to corporate income tax.

I analyze energy investments in this paper assuming that firms are subject to federal and state corporate income taxes. Many energy firms are subject to the corporate alternative minimum tax (AMT). While I do not analyze the corporate AMT in detail in this paper, I do note in various places where my analytic results can be affected by the AMT.[6]

Table 1
Net Stock of Energy-Related Fixed Assets in 2007 ($Billions)

Private fixed assets:		
Equipment and software		523.9
Engines and turbines	83.5	
Electrical transmission, distribution, and industrial apparatus	358.4	
Mining and oilfield machinery	49.5	
Electrical equipment, not elsewhere classified	32.5	
Structures		2,120.4
Power	1,230.6	
Mining exploration, shafts, and wells	889.8	
Government fixed assets		241.5
Power	241.5	
Total		2,885.8

Source: Bureau of Economic Analysis, National Income Accounts, Fixed Asset Tables (http://www.bea.gov).

Table 2
Share of Assets Subject to Corporate Income Tax

Industry	Corporate Income Tax Treatment (%)
Mining	92.3
Utilities	99.6
Petroleum and coal products, manufacturing	99.2
Retail gasoline sales	47.6
Pipeline transportation	68.5

Source: CBO (2006, table 3).

1. Depreciation

Under the current tax code, capital assets are depreciated according to the Modified Accelerated Cost Recovery System with recovery periods ranging from 3 to 39 years. Most capital is depreciated using a declining balance method at either 200% (3-, 5-, 7-, and 10-year property) or 150% (15- and 20-year property) with the option to shift to straight-line depreciation at whichever point it becomes advantageous to do so. Assuming that firms switch to straight-line depreciation at the point at which straight-line provides a larger deduction than declining balance, the two key parameters are the recovery period of the asset and the declining balance deduction rate. Tax depreciation effectively reduces the purchase price of an asset. If z is the present discounted value of the stream of depreciation deductions per dollar for an asset and τ the corporate tax rate, then tax depreciation reduces the price of the asset from one to $1 - \tau \cdot z$.

Electric-generating capital is depreciated over different tax lives depending on the type of plant. Recovery periods range from 5 years for renewable energy to 20 years for coal. High-voltage electricity transmission lines received a 15-year recovery period in the Energy Policy Act of 2005. That act also clarified the depreciation of natural gas gathering (7 years) and reduced the recovery period of distribution pipelines from 20 to 15 years. In addition, the law contained a provision allowing partial expensing for new refinery capacity placed in service before 2012. The provision allows for 50% expensing, with the remainder deducted as under current law.

Oil and gas drilling receives an additional depreciation benefit from the ability to expense dry holes. One can view dry holes as part of the cost of drilling a successful well. This tax provision raises the effective value of the depreciation deductions for oil rigs. Technology, however, has reduced the percentage of dry holes. In 1960, 40% of all wells drilled were dry holes. By 2008, that percentage had fallen to 10%, reducing the tax advantage of dry hole expensing.[7]

2. Depreciation and Fossil Fuel Production

Depreciation of assets in the production of fossil fuels (oil and gas drilling and coal mining) deserves additional attention. Chief among the depreciation preferences are percentage depletion and the ability to expense intangible drilling costs. As noted in Metcalf (2007), these preferences are less generous than they have been historically, but they continue to be significant. A bit of background will help in understanding these tax benefits.

Capital investments to develop oil and gas production sites fall into one of three categories for federal tax purposes. Costs incurred in finding and acquiring the rights to oil or gas are treated as depletable property and are written off over the life of the oil or gas site. These include exploration costs to identify promising sites as well as the cost of up-front (or bonus) bids to acquire sites. Once a site is identified and purchased, its oil or gas enters a firm's proven reserves. As natural resources are extracted from booked reserves, the value of those reserves is diminished. Cost depletion allows a firm to write off depletable costs as the reserve is drawn down. As an example, imagine a field that contains 2 million barrels of proven reserves of oil with exploration and purchase costs of $10 million. Under cost depletion, the firm is allowed to write off the $10 million cost as oil is drilled. Thus if the firm pumps 100,000 barrels of oil from the field in the first year, it would be allowed cost depletion of $500,000 since the amount pumped equals 5% of the proven reserves.[8]

As an alternative to cost depletion, independent oil, gas, and coal producers are allowed to take percentage depletion.[9] Rather than take a depletion deduction based on actual costs, the firm is allowed to take a certain percentage of revenue as a deduction. The current rate for percentage depletion is 15% for oil and gas and 10% for coal. Percentage depletion is allowed on production up to 1,000 barrels of average daily production of oil (or its equivalent for natural gas) for the company. In addition, the depletion allowance cannot exceed 100% of taxable income from the property (50% for coal) and 65% of taxable income from all sources.[10] Continuing with the example above, assume that an independent firm owns this oil reserve and sells the 100,000 barrels of oil pumped in the first year for $60 per barrel. Assuming no taxable income limitations, the firm could take a deduction for 15% of the revenue from the sale of the oil or $900,000. If the firm were to sell the entire reserve of oil at $60 per barrel, its cumulative depletion allowance would be $18 million, 80% greater than the depletable costs of the field.

Significant limits on percentage depletion have been added over time, including a reduction in its rate and limitation to independent producers. Despite the curtailed availability of percentage depletion, it continues to be a significant energy tax expenditure, costing $4.4 billion between 2009 and 2013 according to the 2009 administration budget submission (Office of Management and Budget 2009). On the basis of production data reported in EIA (2009b, table A6), roughly one-half of domestic crude oil production in 2007 came from independent producers potentially eligible to take percentage depletion.

Once a property has been identified, the firm incurs significant costs to develop the site. These costs, which might include site improvement, construction costs, wages, drilling mud, fuel, and other expenses, are called intangible drilling costs (or IDCs). IDCs are all costs for which no salvage value is possible. Typically noncapital costs associated with developing a capital asset are depreciated over the life of the asset under the uniform capitalization rules. In the energy sector, IDCs may be expensed by independent producers. Integrated producers may expense 70% of IDCs and write the remainder off over a 5-year period.[11]

The last capital expense category is the drilling equipment itself. This is written off over a 7-year period using double declining balance depreciation rules. Drilling equipment constituted roughly 10% of total capital costs for new projects in 2007 according to EIA (2008b, table T7). Depletable costs constituted roughly one-quarter of total costs and IDCs accounted for roughly two-thirds of costs.

3. Production and Investment Tax Credits

The federal tax code includes a number of production and investment tax credits on fossil, alternative, nuclear, and renewable fuels. These are included as part of the general business credit and are subject to AMT limitations. Carlson and Metcalf (2008) provide evidence that energy firms are restricted in their ability to use all of their general business credits. While the AMT plays a role, regular tax limitations play a more significant role in limiting the use of general business credits. The important energy-related production and investment credits are as follows.

a. Production tax credits for electricity provided from renewable sources. Production tax credits are provided at a rate of $0.015 per kilowatt-hour (kWh;

indexed in 1992 dollars) of electricity generated from wind, biomass, poultry waste, solar, geothermal, and other renewable sources.[12] Currently the rate is $0.021 per kWh. Firms may take the credit for 10 years. Refined coal is also eligible for a section 45 production credit at the current rate of $5.877 per ton.[13] The Energy Policy Act of 2005 added new hydropower and Indian coal, with the latter receiving a credit of $1.50 per ton for the first 4 years and $2.00 per ton for 3 additional years (in real dollars).

Production tax credits have historically been authorized by Congress for a 2-year period. Considerable uncertainty has arisen a number of times whether Congress would reauthorize the credit or not. The credit lapsed three times (2000, 2002, and 2004) though subsequently was reauthorized retroactively. Distinct declines in wind investment occurred in each of those periods of uncertainty as documented in Wiser and Bolinger (2008). The current credit for wind was renewed in the American Reinvestment and Recovery Act of 2009 and is currently available for projects completed before the end of 2012.

Concern arose in 2008 that the financial crisis was drying up considerable sources of financing for wind projects. Anecdotal evidence suggests that this is a real problem. According to Martin et al. (2009), the number of large financial institutions providing equity to the renewable industry in return for access to tax shields has declined from 18 in the past 2 years to four or five presently. As a response the American Reinvestment and Recovery Act allowed wind projects to substitute a 30% investment tax credit for the production tax credit or a cash grant for up to 30% of the cost of the project.[14]

b. Other production tax credits. The 2005 Energy Act provided a production tax credit for electricity produced at nuclear power plants (sec. 45J). Qualifying plants are eligible for a $0.018 per kWh production tax credit for 8 years up to an annual limit of $125 million per 1,000 megawatts (MW) of installed capacity. This limit will be binding for a nuclear power plant with a capacity factor of 80% or higher. The law places an aggregate limit of 6,000 MW of capacity eligible for this credit.

The American Jobs Creation Act of 2004 (PL 108-357) created a production credit (sec. 45I) for marginal oil and gas producers of $3 per barrel of oil ($0.50 per thousand cubic feet [mcf] of natural gas) in year 2005 dollars. The full credit is available when oil (gas) prices fall below $15 per barrel ($1.67 per mcf) and phases out when prices reach $18 per barrel ($2 per mcf).[15] Marginal wells produce on average 15 or fewer barrels of oil (or oil equivalent) per day.

This same law provided for small refinery expensing of 75% of capital costs associated with low-sulfur diesel fuel production and a $0.05 per gallon small refiner's credit for the remaining 25% of qualified capital costs for the production of low-sulfur diesel fuel. The 2005 Energy Policy Act allowed a pass-through of this credit to owners of cooperatives.

Coke and coke gas producers are eligible for a $3 per barrel equivalent tax credit under section 45K of the tax code. This is the last vestige of the previous section 29 nonconventional oil production tax credit and expired at the end of 2009.

c. Investment tax credits. A 30% investment tax credit is available for solar installations as well as fuel cells used to produce electricity. A 10% credit is available for qualifying microturbine power plants. In addition to credits for renewable energy, the Energy Policy Act of 2005 enacted credits for investments in certain clean coal facilities. Integrated gasification combined cycle (IGCC) plants are eligible for a 20% credit (up to a maximum of $800 million in credits), other advanced coal-based projects are eligible for a 15% credit (up to a maximum of $500 million in credits), and certified gasification projects are also eligible for a 20% credit (maximum of $350 million in credits).

The Omnibus Budget Reconciliation Act of 1990 contained a provision for a 15% credit (sec. 43) for expenditures on enhanced oil recovery tangible property and intangible drilling and development costs and other related capital expenditures. The credit is phased out as the section 29 reference oil price exceeds $28 in 1990 dollars ($37.44 for 2005). At current prices, producers cannot take this credit.

d. Section 40 alcohol and biodiesel fuels credit. The Energy Policy Act of 1978 included an exemption from the motor fuels excise tax for alcohol and alcohol blended fuels, generically known as gasohol.[16] The Windfall Profits Tax allowed an immediate tax credit in lieu of the exemption.[17] The credit was set at a rate to be equivalent to the tax exemption. The alcohol fuel mixture credit is currently $0.45 per gallon of ethanol in gasohol and $0.60 for other alcohol-based fuels (excluding petroleum-based alcohol fuels). In addition, small producers may take a credit of $0.10 per gallon. The 2005 Energy Policy Act increased the small producer production capacity limit from 30 million to 60 million gallons per year.

The American Jobs Creation Act also added section 40A to the code to provide an income tax credit for biodiesel fuels at a rate of $0.50 per gallon of biodiesel (other than agribiodiesel) and $1.00 for agribiodiesel. Like the alcohol fuel tax credit, it is first applied to motor fuel excise tax payments, with the excess added to the general business credit.

B. State Tax Provisions

Most states levy a corporate income tax with top rates that varied from 2% to 12% in 2006. In addition, 35 states impose severance taxes on mineral extraction in their states. Table 3 lists the top 15 states in severance tax collections ranked by amount of collections in fiscal year 2008. Alaska, Texas, and Oklahoma lead the list and account for two-thirds of total U.S. severance tax collections in that year. These three states were among the top five oil-producing states in 2008 (the other two states are Louisiana and California). Wyoming is a significant oil- and gas-producing state as well as the largest coal-producing state in the country. While I do not have detailed data breaking out severance tax collections by fuel, it appears that oil and gas are responsible for the lion's share of revenue.

The 15 states in table 3 account for over 95% of severance tax collections in 2008. For many of these states severance taxes account for a large fraction of total state tax revenues.

In my analysis below of the impact of taxes on energy investment I take the state corporate tax into account. I use an average tax rate of 6.6%, which when combined with the federal corporate tax rate of 35% gives a total corporate tax rate of 39.3%.[18] I assume that severance taxes reduce

Table 3
State Severance Tax Collections in 2008

State	Severance Tax ($ Thousands)	Share of Aggregate Severance Taxes (%)	Share of State Taxes (%)
Alaska	6,939,040	38.0	82.4
Texas	4,131,185	22.6	9.2
Oklahoma	1,184,765	6.5	14.0
New Mexico	1,089,836	6.0	19.2
Louisiana	1,035,695	5.7	9.4
Wyoming	883,786	4.8	40.8
North Dakota	791,692	4.3	34.2
West Virginia	347,592	1.9	7.1
Montana	347,221	1.9	14.1
Kentucky	293,334	1.6	2.9
Alabama	197,581	1.1	2.2
Kansas	168,696	.9	2.4
Colorado	151,474	.8	1.6
Mississippi	135,248	.7	2.0
Michigan	113,506	.6	.5
United States	18,259,637		2.3

Source: U.S. Census Bureau (2009).

the price paid to owners of land on which the taxed energy sources are found. This follows from the inelasticity of supply of reserves and the ease of substitutability among consumers across different state supplies of coal, oil, or natural gas.

III. Effective Tax Rates on Energy Capital Investments

As the previous section makes clear, the treatment of energy in the tax code is complex. In this section I construct a summary measure of the tax code's provisions. The tax literature contains a number of summary measures of the tax code, and two measures are particularly relevant for thinking about capital investment: Hall and Jorgenson's (1967) user cost of capital and marginal effective tax rates (see King and Fullerton [1984] for a treatment of this latter measure). The first statistic measures the required marginal product of capital that a firm must receive in order to pay its marginal taxes and provide a required return to investors. Assuming declining marginal product of capital, a higher user cost of capital is associated with lower demand for capital by a firm. The latter measure is a transformation of the user cost measure that provides the same information in the form of a tax rate. While either measure can be useful for empirical work, the latter is more easily interpreted, and so I report marginal effective tax rate measures in this section.

Specifically, I construct effective tax rates on capital investments in energy infrastructure. An effective tax rate measures the difference in the before- and after-tax return on a marginal investment relative to its before-tax return. More precisely, the before-tax return is the return an investment must earn in order to cover its cost, pay the required return to investors, and pay taxes on the project. The after-tax return is the return that savers expect to receive after taxes on marginal investments.

Following the terminology in CBO (2005), let ρ be the real before-tax return on the marginal investment for a particular capital asset category and r the real return paid to investors. The effective tax rate is defined as

$$\frac{\rho - r}{\rho}. \tag{1}$$

Thus, if savers are prepared to accept 7% on an investment after tax (r) and the project must earn 10% in order to cover depreciation, taxes, and required payments to investors (ρ), the effective tax rate is 30%: $(10 - 7)/10$.

Effective tax rates focus on the marginal cost of funding investments rather than on project cost. In particular, they focus on the cost of a break-even investment. Because they summarize the many provisions of the tax code that affect the returns to capital investment, effective tax rates are frequently used to consider how the tax system affects capital investment. This is a particularly salient issue given the capital investment needs of energy infrastructure in the United States as noted in the introduction.

I follow the methodology of the CBO (2005, 2006) to construct effective tax rates for energy capital. My measures differ from those reported in the CBO reports in two ways. First, I analyze assets at a more disaggregated level than is done in those reports. Second, I take into account more provisions of the tax code than those reports do. In particular, the CBO studies do not account for energy-specific production or investment tax credits or for tax rules specific to the oil and gas industry. I begin with a brief overview of the construction of effective tax rates. Readers seeking a fuller description should read CBO (2006) or any of the references cited therein. I then discuss how I modify the standard effective tax rate measure for energy-specific tax provisions.

If we ignore energy-specific deductions and credits, the required before-tax return is equal to

$$\rho = \underbrace{\frac{(\tilde{r} + \delta)(1 - \tau z)}{1 - \tau}}_{ucc} - \delta. \tag{2}$$

Equation (2) says that the real before-tax return equals the user cost of capital (*ucc*) less the economic rate of depreciation. The parameter $\tilde{r}$ in equation (2) is the real corporate discount rate measured as $d[i(1 - \tau) - \pi] + (1 - d)E$. The discount rate is a weighted average of the real after-tax cost of borrowing, where i is the corporate borrowing rate, π is the expected inflation rate, τ is the corporate tax rate, d is the share of investment financed by debt, and E is the real return on equity. Assets are assumed to depreciate at an exponential rate with the rate of decay equal to δ. The present value of tax depreciation is given by z and depends on tax rules specific to each asset.

Equation (2) makes clear that either the user cost of capital or the effective tax rate measure is a summary statistic for the tax code's various provisions and their impact on marginal investments. In the next section I report regressions using the user cost of capital measure since it is less sensitive to small changes in the firm's discount rate. In this section I focus on the effective tax rate measure since it is a more easily interpretable measure.

In some cases, I compute effective tax rates for investments that are composed of different types of capital, each of which faces its own effective tax rate. In those cases I construct before-tax returns for each capital component and compute the weighted before-tax return for the investment weighting by the share of the component in the total investment cost.

A key element in the taxation of capital assets is the tax treatment of depreciation. Let z equal the present discounted value of the stream of depreciation deductions assuming particular tax rules for an asset. If D_t is the amount of depreciation allowed in year t for an asset with an initial basis of one and a recovery period of T years, then

$$z = \sum_{t=1}^{T} \frac{D_t}{(1+\tilde{r})^{t-1}}. \tag{3}$$

The present discounted value of depreciation deductions is equal to the tax rate times z (assuming that the tax rate does not change over the life of the asset). Thus, the effective after-tax purchase price of an asset is equal to $1 - \tau \cdot z$ times the cost of the asset. Below, I will show how the effective price is affected by energy-specific tax rules.

Table 4 reports tax depreciation rules and estimates of economic depreciation for various energy-related assets. Capital shares are reported in parentheses after each asset type. Capital shares for nuclear power plants are taken from table 4.2.2 of Tennessee Valley Authority (2005). This report provides cost estimates for an advanced boiling water reactor that would be designed and constructed under the new combined construction permit and operating license rules implemented in the Energy Policy Act of 1992. Oil drilling costs vary depending on the particular characteristics of different sites. I have chosen a representative set of cost shares to construct a composite effective tax rate for drilling. The breakdown of intangible drilling costs for integrated firms reflects tax rules allowing expensing for 70% of IDC costs with the remainder to be deducted over 5 years.

The formula for the before-tax return in equation (2) needs to be modified to account for production and investment tax credits as well as for percentage depletion for oil and gas drilling. Investment tax credits at rate κ are a straightforward modification. Production tax credits and percentage depletion are slightly more complicated. Let θ be the capacity factor for a renewable electricity investment. This would equal roughly 30% for wind, for example. A 1 kW facility produces $8{,}760\theta$ kWh of electricity

Table 4
Energy Capital Depreciation

	Recovery Period (Years)	Method (%)	Economic Depreciation Rate (%)
Electric utilities:			
Generation:			
Nuclear:			
Steam turbines (25%)	15	150	5.16
Other equipment (54%)	15	150	5.00
Structures (21%)	15	150	2.11
Coal (PC)	20	150	5.16
Coal (IGCC)	20	150	5.16
Gas	15	150	5.16
Wind	5	200	3.03
Solar thermal	5	200	3.03
Transmission and distribution:			
Transmission lines	15	150	5.00
Distribution lines	20	150	5.00
Petroleum:			
Oil drilling (nonintegrated firms):			
Oil drilling (tangible) (10%)	7	200	7.51
IDC (70%)	Expensed		10.00
Depletable assets (20%)	Percentage depletion		7.51
Oil drilling (integrated firms):			
Oil drilling (tangible) (10%)	7	200	7.51
IDC (70%):			
Expensible IDC (49%)	Expensed		7.51
Deductible IDC (21%)	5	200	7.51
Depletable assets (20%)	Cost depletion		7.51
Refining	10	200	8.91
Natural gas:			
Gathering pipelines	7	200	2.37
Other pipelines	15	150	2.37

Source: Economic depreciation rates taken from Bureau of Economic Analysis (2008).
Note: The economic depreciation rate in the case of percentage depletion is set equal to the depletion rate for a representative well. See the text for more information.

over the year, where 8,760 is the number of hours in a year. If p is the overnight cost of 1 kW of capacity, a 10-year production tax credit is worth (per dollar of investment)

$$\nu = \sum_{t=1}^{10} \frac{8,760\theta s}{(1+\tilde{r})^t p} = \frac{8,760\theta s}{p}\left[\frac{1}{\tilde{r}} - \frac{1}{\tilde{r}(1+\tilde{r})^{10}}\right], \tag{4}$$

where s is the subsidy rate (dollars per kWh).[19]

If we account for production and investment tax credits as well as percentage depletion, the required before-tax rate of return becomes

$$\rho = \frac{(\tilde{r} + \delta)(1 - \kappa - \nu - \tau z)}{1 - \tau + \mu\psi\tau} - \delta, \tag{5}$$

where ψ is the percentage depletion rate and μ the ratio of price to operating profit. The percentage depletion rate for oil is 15%.[20] If percentage depletion is taken, the firm would have no depletion as part of z. The ratio of price to operating profit will vary depending on the particular source of oil. While the price of a barrel of oil is straightforward to measure, the appropriate measure of operating profit per barrel of oil is not. One approach to measuring operating profit might be to take the oil price and subtract production costs (finding and lifting costs). The domestic first purchase price for oil was roughly $60 in 2006. According to the EIA (2007), production costs were roughly $25 per barrel. This suggests a markup of 1.71.

Adelman (1995) cautions that the standard measure of finding costs (the sum of exploration and development expenditures divided by oil and gas reserves added [in oil equivalents]) is a flawed measure. As Adelman notes, exploration adds knowledge but development adds reserves. The knowledge from exploration may add to reserves at present but may not add to reserves for many years. In addition, the conversion of gas into oil equivalents is not stable over time since it depends on how oil and gas are used as well as their relative prices. The EIA study acknowledges the first problem and addresses this by averaging finding costs over 3 years.

Alternatively, one could simply measure operating profit from firm balance sheets. EIA (2007, table 9) reports income and expenses for major energy producers. The ratio of revenue to operating income in 2006 was 1.86. On the basis of these two estimates of the markup ratio (μ), I use a ratio of 1.75 in my calculations below. Table 5 reports the parameters I use in my effective tax rate calculations that are not technology specific.

Table 6 reports my estimates of effective tax rates on new energy-related capital investments based on the formulas described above. I provide estimates for different forms of electric generation capital, other electricity-related capital, and capital used in the drilling and refining of oil as well as in the transport of natural gas.

The first part of table 6 provides estimates of effective tax rates for electric generation capital. Under current law (col. 1), solar thermal and wind capital are subsidized to the greatest extent with effective marginal

Table 5
Effective Tax Rate Parameters

Parameter	Value (%)
Real required return to equity (E)	7
Inflation rate (π)	3
Nominal bond rate (i)	8.6
Federal tax rate (τ_F)	35
Average state tax rate (τ_S)	6.6
Combined tax rate (τ)	39.3

Source: Real required equity return from table 17 in CBO (2006). Nominal bond rate is the 50-year average of BAA bonds taken from table B-73 in Council of Economic Advisers (2008).

subsidy rates of 245% and 164%, respectively. Nuclear power is also heavily subsidized with a subsidy rate of nearly 100%. The effective tax rates for coal and gas are substantially higher than for nuclear or renewables. IGCC capital is subsidized whereas pulverized coal capital (PC) faces a positive tax. The major difference here is the 20% investment tax credit for new IGCC investments. Finally, coal (PC) and natural gas

Table 6
Effective Tax Rates (%)

	Current Law (1)	No Tax Credits (2)	Economic Depreciation (3)
1. Electric utilities:			
Generation:			
Nuclear	−99.5	32.4	−49.4
Coal (PC)	38.9	38.9	39.3
Coal (IGCC)	−11.6	38.9	−10.3
Gas	34.4	34.4	39.3
Wind	−163.8	12.8	−13.7
Solar thermal	−244.7	12.8	−26.5
Transmission and distribution:			
Transmission lines	34.0	34.0	39.3
Distribution lines	38.5	38.5	39.3
2. Petroleum:			
Oil drilling (nonintegrated firms)	−13.5	−13.5	39.3
Oil drilling (integrated firms)	15.2	15.2	39.3
Refining	19.1	19.1	39.3
3. Natural gas:			
Gathering pipelines	15.4	15.4	39.3
Other pipelines	27.0	27.0	39.3

Source: Author's calculations.

combined cycle face an effective tax rate very close to the statutory tax rate (39.3% accounting for state and federal taxes).

Columns 2 and 3 in table 6 indicate the impact on effective tax rates of removing the production and investment tax credits (col. 2) and replacing accelerated depreciation with economic depreciation.[21] The production or investment tax credits are the most significant source of subsidy—as evidenced by the change in the effective tax rate when the credits are removed. The effective tax rate for wind, for example, rises from −164% to −14% if economic depreciation replaces accelerated depreciation whereas it rises to +13% if the production tax credit is eliminated. With economic depreciation and no production or investment tax credits, the effective tax rate in all cases equals the statutory tax rate of 39.3%.

The effective tax rate methodology can be used for other types of energy capital. In the electric utility section, I also construct effective tax rates for transmission and distribution. Transmission lives are allowed a 15-year recovery period whereas distribution lines are allowed a 20-year recovery period. The former face an effective tax rate modestly lower than the statutory rate whereas the latter receive very little in the form of a subsidy.

Effective tax rates in the petroleum sector depend in large part on whether the firms taking the credits are integrated or nonintegrated (independent) firms. Independent firms benefit from full expensing of their intangible drilling costs whereas the integrated firms can expense only 70% of their IDCs and must write the rest off over a 5-year period. In addition, the independents are allowed to take percentage depletion but the integrated firms must use cost depletion.

The effective tax rate on oil drilling equipment depends importantly on the ability to take percentage rather than cost depletion. For independent firms taking percentage depletion, the effective tax rate is −13% whereas firms taking cost depletion face effective tax rates of 15%. The rate for integrated firms is a bit lower than the effective tax rate on refining capital. The effective tax rate for refining capital assumes the temporary 50% expensing provision for capacity additions. This reflects the fact that most new investment in refineries has been in increasing the capacity of existing refineries rather than in building new refineries.[22] In the absence of the temporary expensing provision, the effective tax rate on refinery capital would rise from 19% to 32%. The lower tax rate on gathering pipelines relative to other pipelines reflects the 7-year recovery period for this capital versus the 15-year recovery period for other pipelines.

The effective tax rate for independent firms taking percentage depletion is sensitive to the ratio of price to operating profit per barrel. Figure 2 shows how the effective tax rate changes as this ratio changes. Percentage depletion drives the effective tax rate down as the oil price relative to per-barrel operating profits falls. The rising cost of extracting oil in the United States means that the effective tax rate for independent firms able to take percentage depletion is falling when other factors are held constant.

This section has provided current estimates of effective tax rates for energy capital investment taking into account energy-specific provisions of the tax code. What effect do these provisions have on energy investment? In the next section I make a preliminary estimate of the impact by considering the relationship between taxation and investment in wind power.

IV. Analysis of Wind Investment

In this section I provide an initial analysis of the impact of tax policy on wind investment. I focus on wind because it is the most rapidly growing source of renewable electricity investment in the United States and the perceived importance of the production tax credit in driving that growth. I carry out an econometric analysis of wind investment to measure the impact of the tax code on that investment.

Little empirical work has been carried out to measure the impact of government policy on wind power investment. Kahn and Goldman (1987) measure changes in the rate of return of renewable projects arising

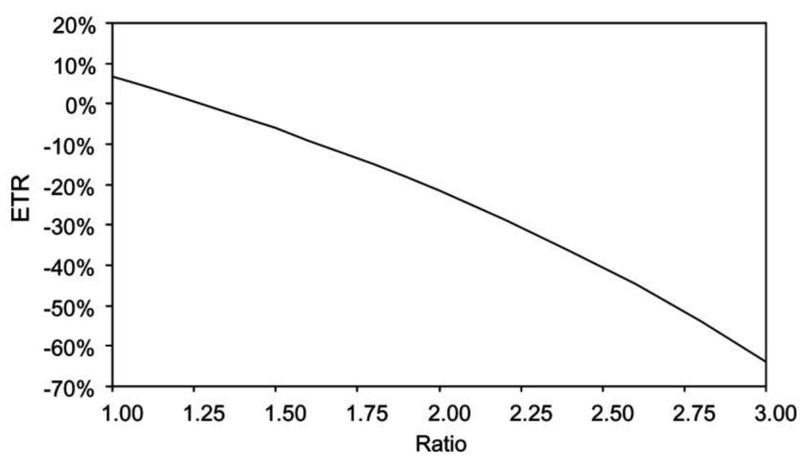

Fig. 2. Relation of effective tax rate to price-profit ratio

from changes in tax law but do not actually estimate tax impacts on investment. Building on the work of Hassett and Metcalf (1999), Grobman and Carey (2003) construct a Markov model to simulate intermittency of government tax policy and find that investment is shifted across periods to take advantage of high-incentive periods in the tax code. The results of their simulations are consistent with the pattern of wind investment observed in the United States (see fig. 3 below). Mulder (2008) considers cross-country panel data of wind investment in the European Union and estimates a number of investment models and finds limited empirical support for the role of policy instruments in driving wind investment. The coefficients on his policy variables are all imprecisely estimated, especially when he allows for country fixed effects. He concludes, on the basis of cross-country differences in wind growth rates, that feed-in tariffs were important drivers of investment in Germany, Denmark, and Spain.[23] Mulder's is the only study I am aware of that empirically estimates investment as a function of tax variables.

Table 7 shows the capacity in various renewable sources of electricity along with growth rates between 1990 and 2007 as well as 2003–7. Renewable sources of electricity account for nearly 11% of U.S. capacity. Of this, nearly 8% is conventional hydroelectric power. Wind is the next most significant renewable source, accounting for 1.7% of total capacity in 2007. Solar-generated electricity accounts for 0.1% of total capacity. The relative growth rates of renewable and nonrenewable energy have shifted over time. While nonrenewable capacity grew at a more rapid rate than renewable capacity between 1990 and 2007, the opposite is true if we focus on more recent investments. Over the past 4 years (for which data are available), renewable capacity has grown at nearly three times the growth rate of nonrenewable capacity. Wind is a major factor driving

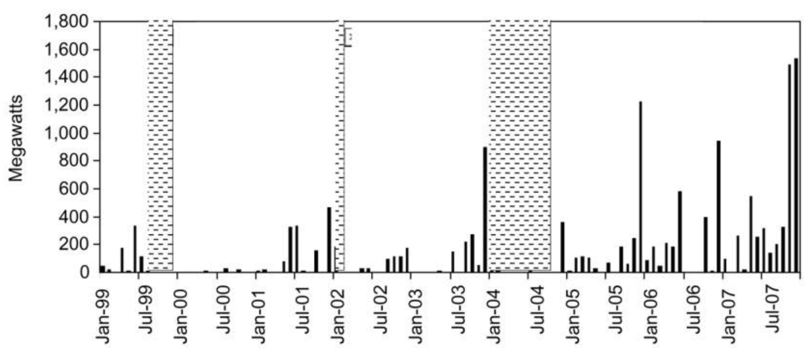

Fig. 3. Wind capacity additions. Source: EIA Form 860

Table 7
U.S. Electric Net Summer Capacity

Source	Capacity 2007 (MW)	Annual Growth Rate (%)		Share of Total Capacity in 2007 (%)
		1990–2007	2003–7	
Renewable total	107,953	1.3	2.8	10.9
Biomass	10,313	1.5	1.7	1.0
Waste	4,134	3.0	2.4	.4
Wood and derived fuels	6,704	1.1	3.4	.7
Geothermal	2,214	−1.1	.9	.2
Hydroelectric conventional	77,884	.3	−.3	7.8
Solar/photovoltaic	500	2.8	5.9	.1
Wind	16,515	13.9	28.8	1.7
Nonrenewable total	886,934	1.9	1.0	89.1
Total	994,887	1.8	1.2	

Source: EIA (2009a, table 8.11a).

the rapid growth in renewable capacity with an annualized growth rate of nearly 30% over the past 4 years.

Of the 16,515 MW of wind-generated electricity capacity in place by 2007, roughly 90% of it was installed in the past decade.[24] Figure 3 shows monthly capacity additions from 1999 through 2007.

Investments in wind occurred in spurts since 1999. Two forces are significant for helping explain wind investment. First, natural gas prices began to rise in 1999. They peaked in January 2001 at $8.91 per mcf—nearly three times the price from the previous January—before collapsing later that year to a low of $3.37. They then began to rise again, hitting $12.16 in October 2005 before retreating a bit and then stabilizing through 2007 at a price between $7 and $8 per mcf.[25]

The second factor affecting wind investments is congressional treatment of the federal production tax credit. The shaded regions in figure 3 show three periods during which the credit expired. While it was in all cases subsequently reinstated retroactively, investors faced uncertainty over the credit's future.

Another factor driving investment in wind is the consistency and power of the wind at available sites. Figure 4 graphs estimates of the annual average wind power in the United States at a height of 50 meters.[26] Wind power is classified in one of seven classes. Classes 3–7 are suitable for wind-generated electricity with higher class numbers more suitable than lower. The map shows considerable heterogeneity, but in general, coastal waters and the Midwest have the most desirable wind power

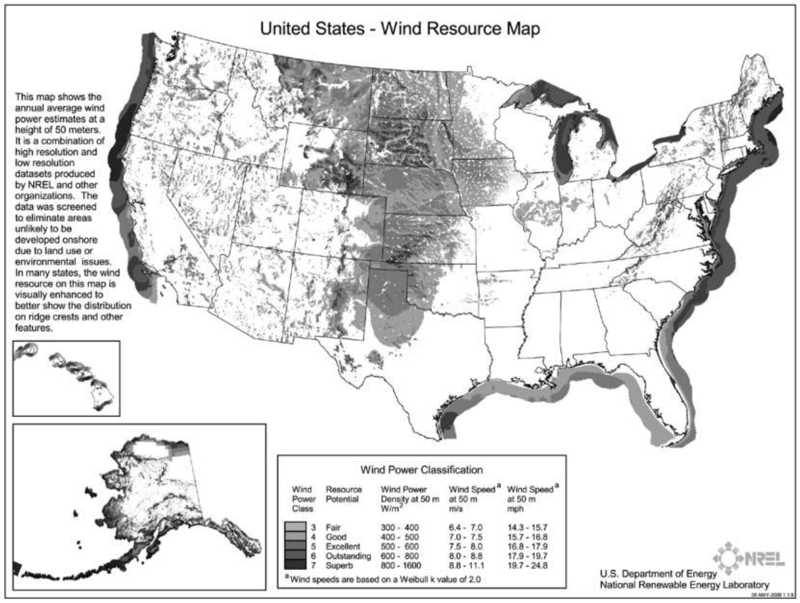

Fig. 4. United States: wind resource map. Source: U.S. Department of Energy, National Renewable Energy Laboratory (http://www.windpoweringamerica.gov/wind_maps.asp).

characteristics. Not surprisingly, the states with the most installed wind capacity as of 2007 were in these areas (Texas, California, Iowa, Washington, Minnesota, and Colorado all have installed capacity in that year in excess of 1,000 MW).

I present some data and analysis of investments in wind capacity between 1990 and 2007 using data from the EIA Form 860 filed by all electricity generators. Table 8 provides information about wind generator investments over the time period. Nameplate capacity of new investments on average was just under 50 MW and showed considerable variation. The average turbine size was 1.2 MW, and the average wind generator was made up of over 40 turbines. Average capacity was more than twice as much for projects installed in this decade compared to the previous decade. This reflects the industry's move to substantially larger turbines.[27]

I constructed user cost of capital and effective tax rate measures for each generator taking into account differences in state corporate tax rates and otherwise using the parameter values from table 5. I constructed estimates of overnight cost by fitting a quadratic regression to the cost data reported in Wiser and Bolinger (2008). Overnight costs in year 2007 dollars decline from $2,400 per kW of installed capacity in 1990 to a low of

Table 8
Wind Generator Investment

	Mean	Standard Deviation	Minimum	Maximum
1990–2007:				
Capacity (MW)	47.7	63.6	.1	300.5
Turbine size (MW)	1.2	.5	.1	3.0
Number of turbines	41.7	61.5	1.0	617.0
1990–99:				
Capacity (MW)	20.8	27.7	.1	112.5
Turbine size (MW)	.6	.2	.1	1.8
Number of turbines	52.1	94.6	1.0	617.0
2000–2007:				
Capacity (MW)	54.4	68.1	.6	300.5
Turbine size (MW)	1.4	.5	.6	3.0
Number of turbines	39.1	50.0	1.0	274.0

Source: Author's calculations from Form 860 data.
Note: Capacity refers to nameplate capacity. There are 325 generators overall for the continental 48 states with 65 in the first subperiod and 260 in the second.

$1,400 per kW in 2002 before gradually rising to $1,559 in 2007. The user cost of capital and effective tax rate measures depend importantly on investor perceptions of the credit during the three periods in which the credit lapsed. I constructed two measures. The first assumes that the credit is in force throughout as, ex post, occurred. The second measure zeros out the credit for any project completed during the time period in which the credit lapsed. This reflects investors' concerns that the credit may not be reinstated.

Table 9 provides summary information on the user cost of capital and the effective tax rates for wind projects in different states and years. The mean user cost of capital assuming the production tax credit is always in force (as it was ex post) is quite low and ranges from 3.4% to 5.7%. This implies highly negative effective tax rates ranging from −1,100% to −65%. The effective tax rate measures here and below are quite sensitive to the after-tax return available to investors elsewhere, and so in regression work below I include the user cost measure as a regressor rather than the effective tax rate.

If investors assume no production tax credit during the period when the credit lapses, the user cost and effective tax rate measures (ucc2 and etr2) are slightly higher. I also include estimates of the user cost and tax rate in which I ignore the production tax credit. The mean user cost rises by 3.6 percentage points, and the mean effective tax rate becomes positive.[28]

Table 9
Tax Statistics (%)

	Mean	Standard Deviation	Minimum	Maximum
ucc1	4.15	.57	3.36	5.69
ucc2	4.57	1.23	3.36	7.92
ucc3	7.77	.07	7.64	7.95
etr1	−362.4	204.9	−1,103.2	−65.5
etr2	−312.5	227.6	−1,103.2	14.4
etr3	12.8	.8	10.5	14.5

Source: Author's calculations.
Note: Statistics on 1,065 observations for generators and continental states between 1990 and 2007. ucc stands for user cost of capital and etr for effective tax rate. ucc1 and etr1 treat the federal production tax credit as continuously in force during the time period. ucc2 and etr2 treat the credit as not in effect for projects initiated during the period in which the credit lapsed. ucc3 and etr3 are measures assuming no production tax credit at all.

I next present an analysis of the impact of the tax code on wind investment. The basic estimating equation regresses capacity investment (Y) on the user cost of capital (*ucc*) and other controls:

$$Y_{ijt} = \beta ucc_{it} + X_{ijt}\gamma + \alpha_i + \varepsilon_{ijt}, \tag{6}$$

where i indexes states, j generators, and t years. For states with no wind investment in a given year I set Y to zero. Before presenting results I must address two issues. The first is that unobserved heterogeneity across states is likely to affect both the desirability of investing in a given state and some of the potential explanatory variables. One factor that may drive wind investment at the state level is the presence of a state renewable portfolio standard (RPS). An RPS program mandates that local electricity distribution companies (LDC) provide some given percentage of their electricity from renewable sources. Typically this is done by the LDC submitting renewable electricity certificates (RECs) for the required amount of electricity. RECs are issued to renewable electricity generators on the basis of their kilowatt-hour production. The generators then sell the certificates to LDCs, which are required to submit them to the RPS regulator. Selling the RECs provides additional revenue for the generator that adds to the profitability of the project.

As of July 2009, 29 states had mandatory RPS programs and an additional five had RPS goals (nonmandatory). Most of these have been enacted in the past 5 years. Figure 5 shows the dispersion across states. Most regions have RPS programs in effect, with the conspicuous absence

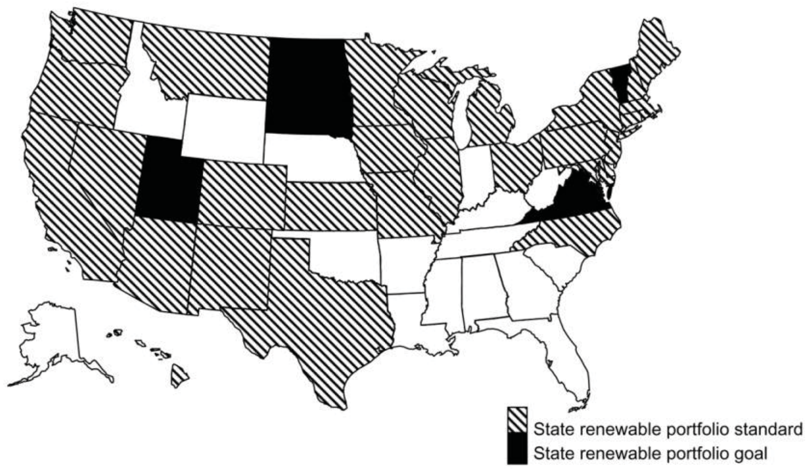

Fig. 5. State RPS programs. Source: Database of State Incentives for Renewables and Efficiency.

of programs in the Southeast. This is perhaps not surprising given the lack of wind resources in this region.

In the econometric analysis I control for the presence of a state RPS program. But this does not entirely address the unobserved heterogeneity issue. I address this issue by including fixed effects, at either the state or regional level. This is valid under the assumption that the unobserved heterogeneity (call this "green tastes") is constant across time within states (or regions).

The second issue is that roughly one-third of my observations on capacity (Y_{ijt}) are positive, with the rest equaling zero. Running an ordinary least squares (OLS) regression is not appropriate for these data. Under the assumption that the error term in a regression with a latent dependent variable (Y^*_{ijt}) measuring desired investment is normal, a Tobit regression is appropriate. The observed dependent variable $Y_{ijt} = \max(0, Y^*_{ijt})$. The only drawback to this approach is that a simple (parametric) transformation of a Tobit model to eliminate the fixed effects does not exist. One can run a Tobit explicitly controlling for the individual effects with dummy variables, but the coefficient estimates are biased for small numbers of time periods. Greene (2004) presents Monte Carlo results that suggest that the parameters of interest—for us the coefficients on the user cost of capital—are unaffected by the presence of fixed effects. He shows that the estimated standard errors are affected by the presence of fixed effects. For that reason I will present robust standard error estimates below. Moreover, Greene notes that the bias is negligible as the number of time periods rises. Given the large number of years in the sample ($T = 18$), any bias in the estimated standard errors is likely to be trivial.

Regression results are presented in table 10. Column 1 reports an OLS regression of investment on the user cost of capital measure, an RPS dummy, along with state and year fixed effects. The user cost coefficient is negative as expected though not precisely estimated. The coefficient on the RPS dummy is positive as expected and precisely estimated. Because of the large number of zero observations, however, we should view this regression with some caution. The remaining regressions on investment capacity are Tobits. Column 2 reports a Tobit regression with state and year fixed effects. The coefficient on the user cost is now much larger in absolute value, though as I discuss later, one cannot directly compare the two estimated coefficients. The p-value on the user cost coefficient is .003. The RPS dummy has the expected sign but is not statistically significant.

Figure 6 graphs the year effects from this regression as well as the national average price for natural gas (city gate price). Not surprisingly, capacity additions track natural gas prices reasonably closely as would be expected if wind serves as a substitute for natural gas power plants. The correlation between the year effects and the gas price is .80.

Most of the variation in the RPS variable is across states, and so I report a regression in which I replace the state fixed effects with region fixed effects. This also allows me to maintain more observations in the regressions since the Tobit fixed effects regression requires dropping all states for which no investment occurs over the sample. I group states into the nine census regions.[29] This approach is reasonable if the unobserved tastes for renewable investment are constant within regions. The estimated coefficient on the user cost of capital increases in magnitude as does the coefficient on the RPS dummy. The latter is now statistically significant.

Finally, I report a Tobit regression in which I do not include state fixed effects. The estimated coefficient on the user cost variable increases in absolute value by roughly 60%. This suggests that failing to control for correlated and unobserved heterogeneity leads to an overestimate of the impact of tax policy on investment.

In summary, the coefficient on the user cost variable is precisely estimated and robust to regression specification. As a final check I run another set of regressions in which I control for the size of the state (cols. 5–8 of table 10). With other factors held constant, one might expect that more wind projects would be put in larger states. Thus I run regressions in which the dependent variable is installed capacity divided by the area of each state (in thousand square miles).

Table 10
Capacity Investment Regressions

	OLS (1)	Tobit (2)	Tobit (3)	Tobit (4)	OLS (5)	Tobit (6)	Tobit (7)	Tobit (8)
Dependent variable	Capacity	Capacity	Capacity	Capacity	Capacity/sq. mi.	Capacity/sq. mi.	Capacity/sq. mi.	Capacity/sq. mi.
User cost of capital	−273.2	−1,064.5	−1,253.1	−1,641.3	−4.89	−14.40	−16.60	−23.54
	(227.6)	(311.5)	(346.8)	(382.9)	(3.71)	(3.84)	(4.35)	(4.60)
RPS dummy	13.5	6.4	30.8	49.0	.07	−.07	.22	.36
	(11.2)	(12.7)	(8.5)	(9.2)	(.11)	(.16)	(.11)	(.10)
State fixed effects	Yes	Yes	No	No	Yes	Yes	No	No
Region fixed effects	No	No	Yes	No	No	No	Yes	No
R^2	.232	.128	.139	.081	.181	.340	.339	.209
Observations	1,065	723	1,065	1,065	1,065	723	1,065	1,065

Note: All regressions include year effects. Robust standard errors are reported in parentheses. For the Tobit regressions pseudo R^2's are reported.

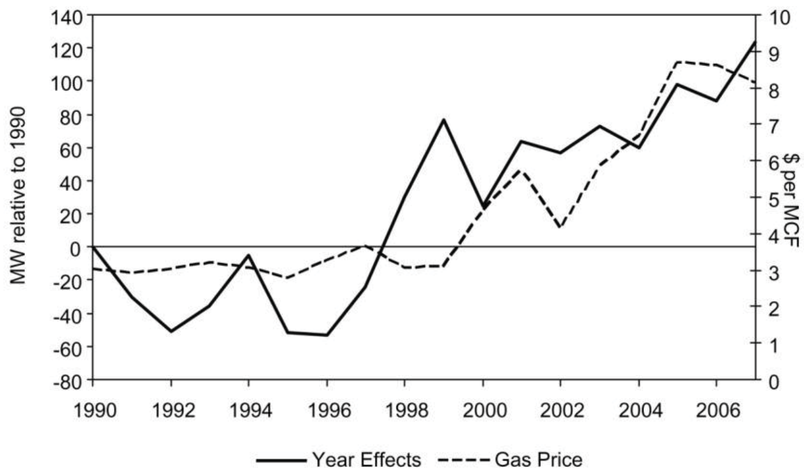

Fig. 6. Year effects and natural gas prices

These regressions are very similar in nature to the regressions on installed capacity. The coefficient on the user cost of capital continues to be precisely estimated whereas the RPS coefficient is precisely estimated only in the model with region dummies. Again failing to control for unobserved state-level heterogeneity biases the tax effect in an upward direction (in absolute value).

In addition to the regressions reported in table 10, I ran various other regressions not reported here. First, I ran a regression in which I include state-specific city gate prices for natural gas and measures of wind power at sites where wind projects are located (average values for states in years with no investment).[30] After year effects are included—which as we have seen are strongly correlated with investment activity—the coefficient on the natural gas variable has the expected sign but is imprecisely estimated. This is perhaps not surprising since little variation is left in the gas price data after state and year fixed effects are included. The wind power coefficient is precisely estimated but has a negative sign. Since I include state fixed effects in the regression, the wind power variable is picking up variation within the state in wind power. It may simply be that, conditional on average wind power in a state, variations around the average are simply not that important in siting decisions (or are correlated with other unobserved state-specific siting variables). Including these variables has little effect on the user cost of capital coefficient.

Second, I ran regressions in which I replaced the user cost of capital variable with the user cost variable that ignores the production tax credit lapses. The regressions exhibit a poorer statistical fit, and the coefficients on the user cost have the wrong sign and are implausibly large. This provides support for the view that investors were not confident that the federal government would reinstate the production tax credit when it lapsed and that the reinstatement would be retroactive.

Third, I ran regressions to control for the possibility that investors were temporarily shifting investment in anticipation of a credit lapsing or being reinstated. Specifically, I dropped observations for all months just before or just after a credit lapsed or was reinstated. For example, the production tax credit lapsed for the first time after June 30, 1999, and was reinstated as of December 19, 1999. I dropped observations for June and July 1999 to eliminate investments that may have been moved up 1 month and I dropped observations for December 1999 and January 2000 to control for investments that may have been shifted from December 1999 to the following month. Regression results were not affected by dropping those observations.[31]

Let me next turn to a discussion of interpretation of the estimated coefficients on the user cost variable in the Tobit regressions. As I noted above, Tobit coefficient estimates cannot be directly compared to OLS estimates. We need to adjust the former to obtain marginal impacts that are comparable to coefficients in the OLS model.[32]

The adjustment to estimated coefficient can be computed in a number of ways. If I compute the CDF at the mean values of the right-hand-side variables, I obtain an estimate of the partial effect at the average (PEA). Alternatively, I can compute the CDF at the observed values of all the observations and take the average. This is the average partial effect (APE). I report both for the regression in column 2 of table 10. The PEA equals −323.13 and the APE equals −417.33. These two estimates are both substantially larger than the OLS coefficient estimate on the user cost variable in column 1. In other words, running OLS leads to a large underestimate of the tax impact on investment.

The average user cost of capital in the sample equals 4.57%. This rises to 7.77% if the production tax credit is eliminated. This implies a decline in annual average investment of 10.3 MW if the PEA is used and 13.4 MW if the APE is used. These declines represent 71% and 92% of average investment over the sample, suggesting that the production tax credit plays a very substantial role in wind investment.[33]

Another way to measure the impact of tax policy on investment is to measure the elasticity of investment with respect to the user cost. If the PEA is used, the elasticity at the mean is −1.01. It equals −1.30 if the APE is used. Either way, the response is large.

The effects are even larger if we control for the size of the state. If the coefficient estimates from column 6 are used, the APE is −7.18 and the PEA is −8.09. Again these are considerably larger than the OLS impact. Raising the user cost of capital from 4.57% to 7.77% to model the elimination of the production tax credit implies a decline in investment of 0.23 MW per 1,000 square miles based on the APE and 0.25 MW per 1,000 square miles based on the PEA. Both of these declines exceed the mean investment per 1,000 square miles in the overall sample (0.16 MW per 1,000 square miles). The elasticity at the mean is −2.37 with the PEA and −2.11 with the APE.

With sufficiently strong assumptions we can make a ballpark estimate of the impact of carbon pricing on investment in wind capacity. Consider the year effects as graphed in figure 6 against natural gas prices. If we make the strong assumption that the year effects are perfectly proxying for natural gas price effects on investment, we can compute an elasticity of capacity investment with respect to natural gas prices. Using the doubling of gas prices between 1990 and 2004 and computing the APE for the marginal impact, we obtain an elasticity of investment with respect to the natural gas price of 1.7. A recent analysis of the Waxman-Markey bill by the U.S. Environmental Protection Agency (2009) suggests that the price of permits in 2020 will be $16.31 (scenario 2 of the ADAGE run). This will raise natural gas prices by 8.5% relative to the reference scenario. On the basis of my elasticity estimate, this would raise investment in wind capacity by 14%.[34] The ADAGE analysis reports an increase in wind capacity investment of 9% by 2020.[35] My estimate is higher than the ADAGE estimate but reasonably close given the simplifying assumptions my analysis makes. While my estimate is admittedly very rough, it suggests that wind investment should be quite responsive to carbon pricing.

The regression estimates in this section show a strong response of wind investment to changes in tax policy. They also suggest that production tax credits strongly influence wind investment. These findings support the received wisdom that production tax credits are critically important for the penetration of wind-generated electricity in the United States. It also suggests that we will continue to see considerable support for this credit as we approach the end of 2012 and the credit's expiration.

It should be noted, however, that the econometric results here depend critically on the assumptions of the Tobit model in a data set with a large fraction of censored observations. It would be valuable to subject the wind capacity data to more sophisticated econometric techniques to see if the results found here are robust. This is especially the case given the lack of other empirical work measuring the impact of renewable investment behavior to energy tax and climate policy.

V. Conclusion

The federal tax code has historically played a major role in shaping U.S. energy policy. Tax-based subsidies account for nearly two-thirds of all federal financial support for energy markets (EIA 2008a) in 2007. As detailed in this paper the tax provisions are complex and constantly in flux. Currently, for example, wind developers may receive a production tax credit or investment tax credit or cash rebate comparable to the investment tax credit. The wind credits, however, expire at the end of 2012 in the absence of further government action. At the same time, Congress is currently considering enacting climate change legislation that will dramatically affect energy markets.

While much has been written on the various tax subsidies to energy, less is known about their impact on investment and production. This paper contributes to that literature by considering the impact of taxes on wind investment. I find that investment in new capacity (measured in megawatts) is strongly influenced by tax policy. The estimated elasticity of capacity investment with respect to the user cost of capital exceeds one. Moreover, the data suggest that much of the current investment in wind can be explained by the production tax credit for wind.

An important question for Congress and the administration going forward is whether it makes sense to maintain many of the tax-based subsidies if comprehensive climate change legislation is enacted. Elsewhere I have noted a number of problems with a subsidy-based approach to energy policy (see Metcalf 2009b). An important question for future research is whether carbon pricing through a cap and trade bill or carbon fee can generate levels of investment comparable to those of the current tax-based subsidies. While economic principles suggest that it should (if designed at comparable levels), it will be important to test this empirically.

Endnotes

This paper was written for the 2009 NBER Tax Policy and the Economy conference. I wish to thank Jeff Brown for helpful comments, Zhuyuan Zhou for her expert assistance in the data collection and analysis, and the Manhattan Institute for Policy Research for financial support.

1. Up to 5% can be provided through energy efficiency improvements.

2. Energy consumption totaled 101.5 quads in 2007. The difference between consumption and production is made up of energy imports. In 2007 the United States imported (net of exports) 26.6 quads of crude and petroleum products and 4.0 quads of natural gas.

3. This estimate does not include energy capital in the U.S. military, nor does it include the value of transportation assets or computers and other equipment used in the production and distribution of energy. Adding transportation-related equipment and structures alone would add an additional $1.3 trillion to the value of energy-related fixed assets.

4. This section and the next draw on Metcalf (2009a).

5. Firms not subject to corporate tax treatment include S corporations, individuals participating in partnerships, and sole proprietorships.

6. Carlson and Metcalf (2008) provide results on the AMT's impact on the use of tax credits in the corporate income tax.

7. Exploratory wells continue to have high failure rates. In 2008, 32% of exploratory wells were dry holes and 8% of development wells were dry holes. But only 5,600 exploratory wells were drilled that year compared to over 50,100 development wells. Roughly 34,000 development wells were drilled in 1960 with a dry hole rate of 25%. However, 11,700 exploratory wells were drilled, with over 80% of them being dry holes. Data are taken from the EIA's Web site (http://tonto.eia.doe.gov/dnav/pet/pet_crd_wellend_s1_a.htm).

8. Geological and geophysical costs may be amortized over 2 years (7 years for the majors).

9. Independent producers are defined as producers that do not engage in refining or retail operations. The 2005 Energy Policy Act increased the amount of oil a company could refine before it was deemed to engage in refining for this purpose from 50,000 to 75,000 barrels per day.

10. Amounts in excess of the 65% rule can be carried forward to subsequent tax years.

11. IDCs are not counted as a preference under the AMT.

12. Open-loop biomass is eligible for a credit of $0.0075 per kWh in 1992 dollars.

13. Refined coal is a synthetic fuel produced from coal with lower emissions of certain pollutants.

14. Bolinger et al. (2009) assess the relative advantages of the various options.

15. The sec. 29 reference price is used to determine eligibility for this credit.

16. Originally, the law provided a full exemption from the then $0.04 per gallon tax. As the motor fuels excise tax was raised over time, the exemption did not keep pace with the excise tax rate. See General Accounting Office (1997) for an early chronology of events related to this tax exemption.

17. The American Jobs Creation Act of 2004 subsequently eliminated the tax exemption in favor of the tax credit.

18. The state corporate tax rate is deductible from federal corporate income taxes. Thus the aggregate rate equals $35\% + (1 - 35\%)(6.6\%)$ or 39.3%. The state average tax rate is taken from the Ernst & Young corporate state tax data set as reported in Ernst & Young (2007).

19. Since the effective tax rate methodology generally uses continuous time analogues, an alternative formula is

$$v = \frac{8,7600s}{p}\left(\frac{1 - e^{-10\tilde{r}}}{\tilde{r}}\right).$$

20. I ignore any net income limitations in this calculation. My treatment of percentage depletion follows that of the CBO (1985) study on oil and gas.

21. Here the effective tax rate formula uses the exponential economic depreciation rate for tax depreciation rather than approximating it with straight-line depreciation.

22. The number of operable refineries has been steadily declining from its recent peak of 324 in 1981 to 150 in 2008. Gross inputs to refineries, however, have increased by nearly 20% over this same period. See EIA (2009a, table 5.9).

23. Feed-in tariffs are mandated minimum prices utilities must pay for electricity generated by specified renewable sources. These are typically combined with requirements that a certain amount of electricity be generated from renewable sources.

24. Cumulative capacity at the end of 1997 was 1,542 MW.

25. These are city gate prices reported by the EIA in nominal dollars. The EIA began reporting data on prices paid by electricity generators only in 2003. The prices paid by electricity generators are on average $0.54 per mcf lower than the city gate price and generally are lower month to month. The correlation between the two price series since the EIA began reporting utility prices is .97.

26. The map was developed by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy and is available at http://www.windpoweringamerica.gov/wind_maps.asp.

27. The median turbine size in both subsamples is similar to the mean. The median number of turbines declines from 16.0 to 15.5, reflecting the fact that fewer projects with large numbers of turbines were initiated in this decade.

28. It is still well below the statutory rate because of the benefits of the 5-year tax write-off of wind capital.

29. The states in each region are as follows: New England: Maine, New Hampshire, Vermont, Massachusetts, Connecticut, and Rhode Island; Mid-Atlantic: New Jersey, New York, and Pennsylvania; South Atlantic: West Virginia, Virginia, North Carolina, South Carolina, Georgia, Florida, District of Columbia, Maryland, and Delaware; East South Central: Kentucky, Tennessee, Missouri, Alabama, and Mississippi; East North Central: Wisconsin, Illinois, Michigan, Indiana, and Ohio; West North Central: North Dakota, South Dakota, Nebraska, Kansas, Minnesota, and Iowa; West South Central: Texas, Oklahoma, Arkansas, and Louisiana; Mountain: Montana, Idaho, Wyoming, Nevada, Utah, Colorado, Arizona, and New Mexico; Pacific: California, Oregon, Washington, Alaska, and Hawaii.

30. Ideally I would use gas prices paid by electric utilities. The EIA begins reporting these data only in 2003.

31. I experimented with longer windows but the Tobit regressions did not converge. Longer windows may not be appropriate anyway. Moving investment forward in time is very difficult given bottlenecks in production, and delaying a project is quite costly given the capital costs that have been incurred prior to start-up. Flexibility in project timing on short notice, therefore, is quite limited.

32. The marginal impact is given by

$$\frac{\partial E(Y_{ijt}|\mathrm{x})}{\partial x_{it}} = \beta_j \Phi\left(\frac{\mathrm{x}\beta}{\sigma}\right),$$

where $x\beta$ is the predicted value of the dependent variable from the Tobit regression, σ is the estimated standard error from the regression, and Φ is the standard normal cumulative distribution function (CDF). See, e.g., Wooldridge (2009).

33. For this calculation, I compute the average over the entire sample as opposed to conditioning on positive investment as in table 8.

34. Given the estimated standard error on the 2004 year effect and conditional on mean wind capacity, the standard error of the elasticity estimate is 0.6. For an 8.5% increase in the price of natural gas, this suggests a one-standard-deviation bracket of this estimated increase in wind capacity between 9.4% and 20.0%.

35. ADAGE actually reports estimates for wind and solar. But the bulk of this capacity is likely to be wind.

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