Center for Energy Economics and Public Policy

Estimating the Impact of State Taxation Policies on the Cost of Wind Development in the West

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Executive Summary

Wind development offers local economic growth opportunities, and for this reason, reducing the tax burden on wind development may be a policy advocated by communities wishing to attract such investment. Alternatively, increased local public costs, and the potential externalities caused by wind development may create a reason to raise taxes on wind. Increased taxation on wind presents a potential policy tradeoff as efforts to raise taxes and revenues from wind can reduce a state's ability to attract wind development. Local tax environments can affect which regions successfully attract wind investment due to their effect on developer's costs. Estimates of the potential tax elasticity of wind development are undeveloped in the academic and policy literatures, thus policy changes with respect to taxation often occur without any estimate of the potential impact on development. Absent such tax elasticity estimates, comparative estimates of regional wind costs and how they may be affected by state tax policy would be useful to policy-makers, but such estimates are also limited. To our knowledge, the only effort to compare state wind costs across western states and how they vary when state tax policies are included was conducted by a private firm in 2010 (see E3 (2010)), and that study is now well out of date. The study presented here develops such state wind cost estimates by describing the financial structure of a typical large utility-scale wind development. Consideration of the capital structure of a wind development is crucial to understand how different taxation and other incentive policies affect wind development, and to develop taxation strategies that minimize wind development and tax-policy tradeoffs.

The results presented here develop a set of levelized cost (referred to as average costs of energy or ACOE) estimates across eleven western states for a typical. The costs are expressed as dollars per Megawatt-hour ($/MWh) of electricity produced. For the computations of ACOE presented, projects were assumed to use current technology and project size assumed was 300 MW (approximately 100 to 130 turbines). None of the cost modeling included transmission development. The two most significant determinants of ACOE differences across all eleven WECC states were (i) resource differences, which affect a state's capacity factor and therefore the expected hours and generation output that the costs are expressed in, and (ii) state differences in construction and labor costs that affect the cost of project construction and operation. Given the differences in resource quality and construction costs across the west, ACOE for each state was computed under two scenarios. To remove resource and regional cost differences from the resulting estimates, an ACOE cost calculation was performed across states assuming each had identical labor and construction costs, and each state was assumed to have a 35 percent capacity factor in the first year of operation, with the output degrading at a 1 percent rate across all remaining years of a project's life. In these estimates, only state tax and incentive policies differ. The second scenario computed more realistic ACOE estimates across states, applying the regional cost differences and using capacity factors estimated to be found in the top 5 percent of locations by state.

Figure E1 presents the estimated ACOE range by western state. Values on the right-hand side of the range are the computed ACOE using constant capacity factor and identical regional cost assumptions. Those on the left of each bar represent the ACOE when state capacity factor and regional cost differences are considered. Both high and low-cost estimates for each state account for specific state incentives and tax differences. New Mexico appears twice in the chart as projects may or may not take advantage of industrial revenue bonding and associated payments in lieu of taxes or tax payments at negotiated rates (most projects take advantage of local bonding). The estimates indicate that across western states and including state tax policy conditions, the lowest cost state to develop wind in the west is New Mexico, followed by Montana and Colorado, with Wyoming placing fourth.

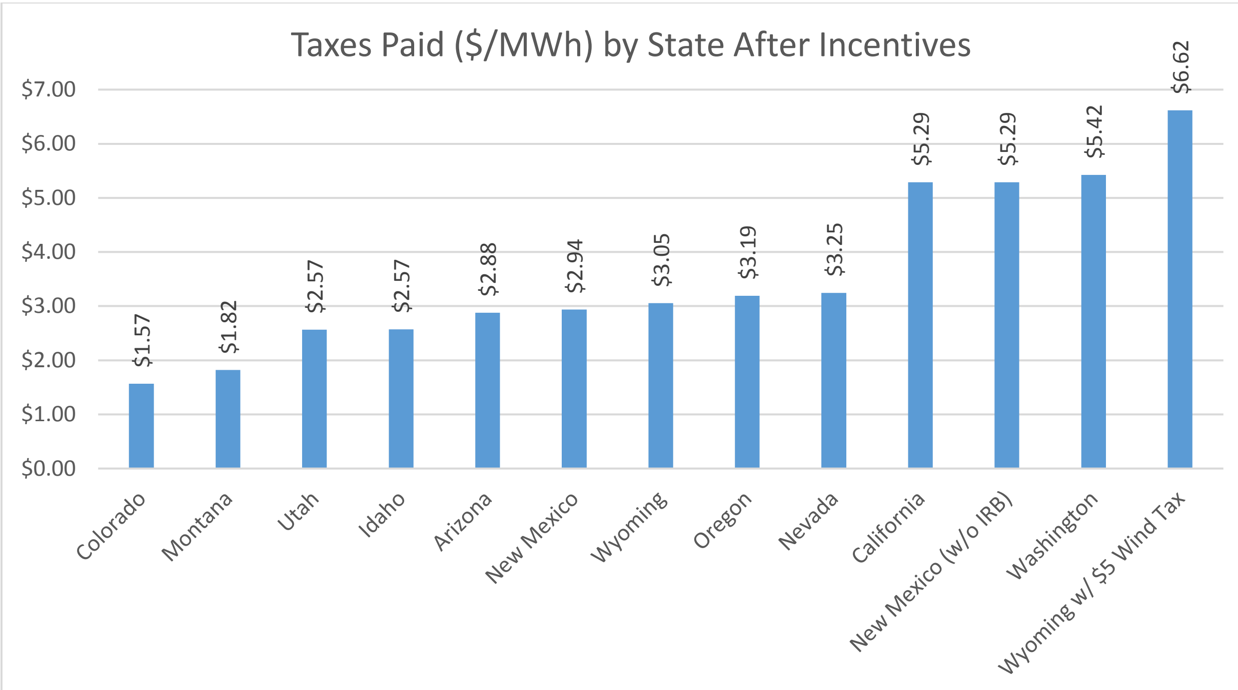
Figure E1: Estimated Average Cost Energy Ranges by WECC State

The estimated cost difference between Wyoming and the lowest cost state (New Mexico) is about 10% regardless of whether a 20- or 30-year project lifetime is assumed. The cost difference between Wyoming and the next two states (Colorado and Montana) is approximately 3%. Figure E2 describes the relative tax burden on wind development in the western states considered. In Wyoming, the estimated tax burden per MWh of electricity production is between $3.05 and $4.21 for new development depending on the wind resource (capacity factor) and construction and operations cost differences between states. Using current realized capacity factors seen in the state at the best performing wind facilities, the tax cost for new wind development would be $4.01 per MWh of production. This is a somewhat lower than the $4.52 per MWh estimated in a previous study (Godby et al., 2016), but the difference can be accounted for by the fact that wind development capital costs have declined, and capacity factors increased since the last wind facilities were built in the state almost a decade ago.

In the past few years, proponents of increasing Wyoming's $1 per MWh production tax have advocated increasing it to $5 per MWh. As shown in Figure E1, this tax change would raise Wyoming's wind development cost by 10%, causing the cost to develop wind in Wyoming to be 21 percent greater than in New Mexico, and 12-13% higher than development costs in Colorado and Montana. The overall tax burden in Wyoming for this policy change would more than double the lowest estimate of tax burden in the state from a value of $3.05 per MWh, to $6.62 per MWh, the highest tax burden across all western states. Our conclusion is that this cost change could have a significant negative impact on wind developers' willingness to consider Wyoming, and undermine the potential use of wind development as an economic diversification strategy, as recently advocated in a state report (ENDOW, 2018).

An additional disadvantage of the proposed tax increase is the fixed nature of the tax burden. Over time, wind costs have been declining on a per MWh basis due to reductions in capital costs, and due to increases in wind productivity as demonstrated by rising capacity factors. This trend is expected to continue. When taxes are assessed on a percentage basis, as is the case with income, gross receipts, property and sales taxes, in a declining-cost environment taxes payable typically decline as well. A fixed cost tax like the $1 per MWh production tax that is unique to Wyoming, however, has the opposite effect on tax burden, increasing as costs decline. Over time, such a tax structure will make the state more uncompetitive if costs continue to decline, and this problem would only be exacerbated if the state increases its revenue reliance on such taxation policy, for example by imposing a $5 per MWh wind tax.

Figure E2: Comparative Tax Burdens on Wind development by State for New Wind Development

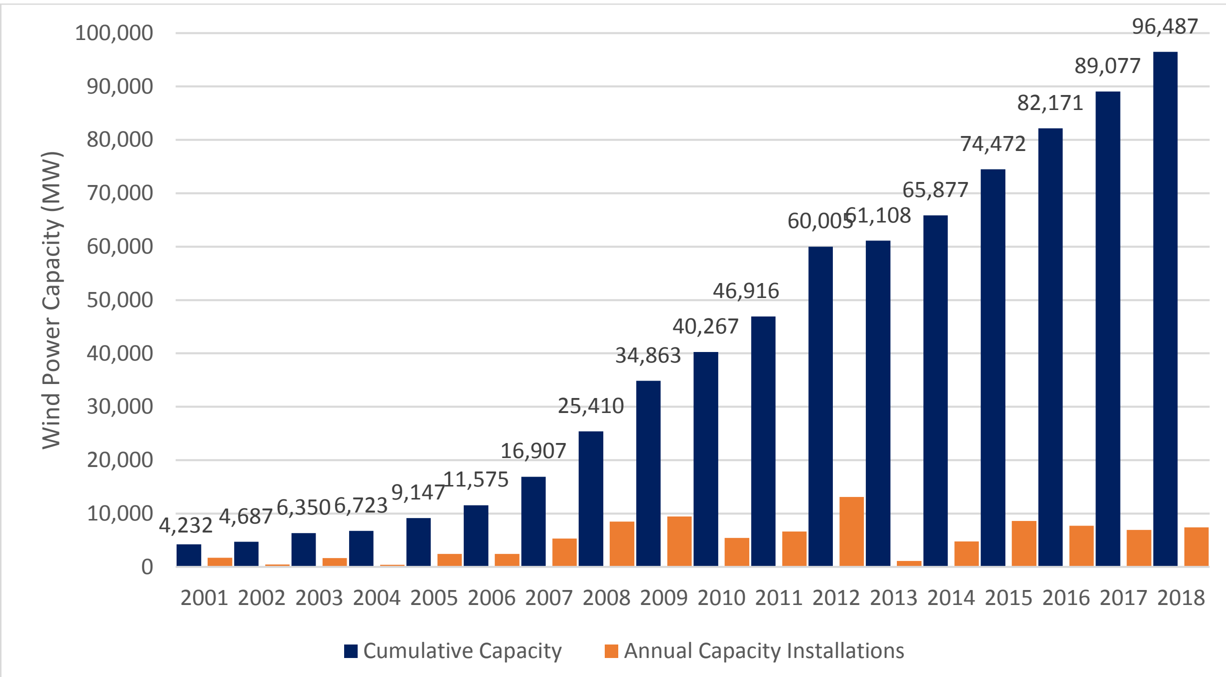


If Wyoming wishes to increase tax revenues from wind development, lessons from other states may be useful. Consideration of academic literature on wind development and investigation of other state practices suggest that tax incentives after project completion are weaker drivers of investment than those that affect initial project financing conditions, such as sales taxes, and this insight may be useful in building wealth in rural western communities where wind development could occur. New Mexico's tax policies could be especially instructive in this regard. Increases in property taxes or the use of a gross receipts tax on wind in Wyoming to replace the wind production tax currently imposed could reduce disincentives to wind development while increasing wind tax revenues. We present a simple example here and suggest that eliminating current sales and production taxes on wind and replacing them with a gross receipts tax could both lower the cost of wind development in the state by 1.5 percent and raise tax revenues from wind generation over the lifetime of a project by over 8 percent. Furthermore, efforts that reduce the cost of financing wind development, potentially through the issuance of industrial revenue bonds, could also reduce the cost of wind development while increasing tax revenues per megawatt hour of production. Such considerations may be fruitful avenues of further investigation if the state wishes to increase wind development and tax revenues per unit of wind generation. Overall, greater consideration of how tax changes will affect development costs in Wyoming should be seriously considered before new policies are implemented to avoid any unintended consequences of such tax changes.

Introduction:

Wind energy offers a major economic development opportunity for many rural communities nationwide. Expansion of wind generation capacity over the past decade has been significant (see Figure 1), growing over 8 percent in 2018, and almost quintupling in capacity since 2008 (AWEA, 2019). Present high rates of growth are anticipated to continue through at least the early part of the next decade.[1] There are many reasons for this wind energy expansion, and one is cost. Estimates of unsubsidized levelized wind generation costs have fallen by 69 percent since 2009 (see Figure 2), and by levelized cost are now the cheapest form of new generation according to industry estimates (see Lazard, 2019).

Figure 1: US Wind Generation Capacity (MW)



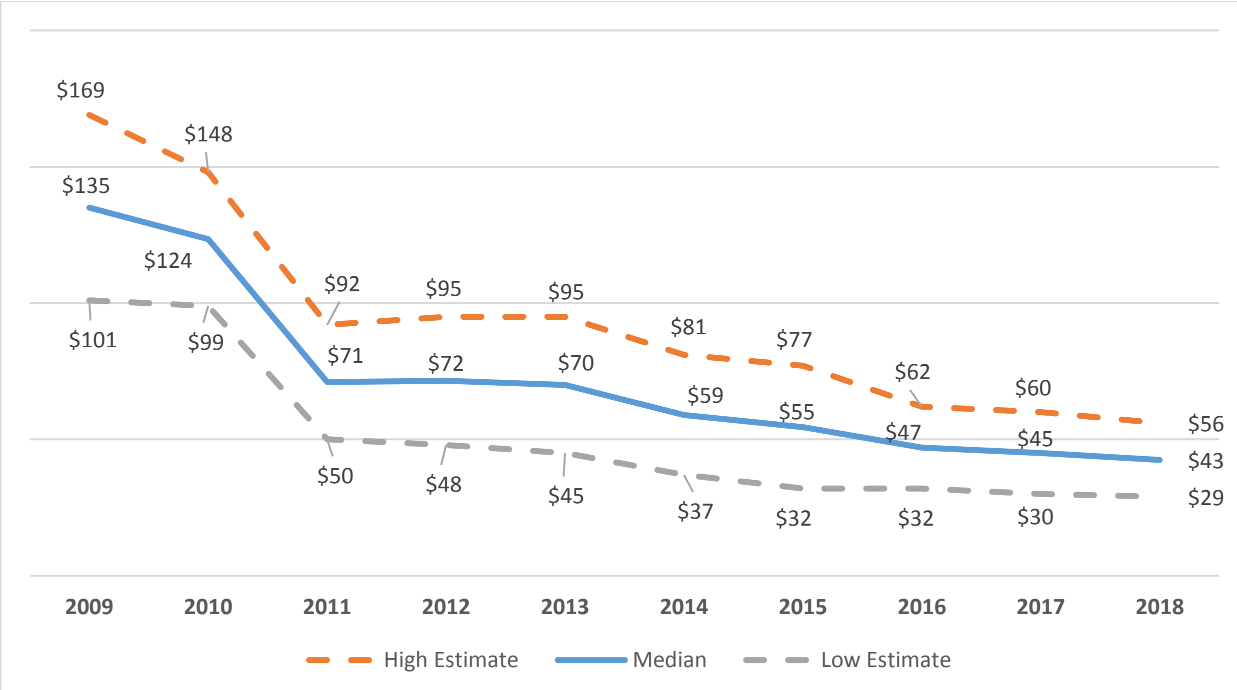
Source: AWEA, 2019.

This growth has created economic development opportunities across the rural United States, and the local economic impacts of wind development can be sizable, as other authors have argued (see for example Slattery, Lantz and Johnson (2011), Brown et al. (2012), Black et al. (2014), and Godby et al., (2018)). In the rural western and midwestern United States, wind development often offers an opportunity for fossil-energy producing states to create new sources of growth in employment, output and tax revenue, especially given recent challenges to traditional energy sector commodities in the recent past due to falling oil and natural gas prices, and reduced coal production due to the on-going decline of coal generation nationally. The expansion of wind development creates both a new source of revenue for

[1] See, for example, the projections contained in the U.S. Energy Information Agency (EIA) Annual Energy Outlook (2019). In the 2019 EIA's reference case, between 2018 and 2022, installed wind capacity is anticipated to increase by almost 25%, assuming current regulations and incentive programs, and current trends in the costs of alternative fuel sources used in electricity generation. See https://www.eia.gov/outlooks/aeo/data/browser/#/?id=67-AEO2019&region=3-0&cases=ref2019&start=2017&end=2050&f=A&linechart=~ref2019-d111618a.12-67-AEO2019.3-0&ctype=linechart&sourcekey=0 Accessed February 20, 2018.

public services and an opportunity for states with good wind resources to both diversify their economies and revenue structures (see for example ENDOW (2018), New Mexico, (2015)).

Figure 2: Estimated Unsubsidized Wind Levelized Cost of Energy ($/MWh)



Source: Lazard (2018)

Wind development creates both short- and long-term economic benefits. The potential for such benefits has been documented in numerous studies using several methodologies. These have quantified the benefits across projects nationally using econometric methods (for example, see Brown et al., 2012), estimated impacts to specific states using standard input-output methods to identify potential direct, indirect and induced impacts within states (see for example Slattery et al., 2011, Godby et. al., 2016), or identified benefits of specific wind projects using case study approaches to determine gross direct impacts (see for example Pedden, 2006). Short-term benefits can benefit local communities during wind facility construction, when significant new economic activity due to the direct benefits of construction activity and employment occur, and through indirect and induced effects on output and employment through increased demand for local goods and services caused by construction activities (e.g. materials, vehicles, fuel, other consumables, and housing and lodging services).

Over the longer-term, the operation of wind facilities creates additional direct benefits locally through continued employment of personnel, and on-going demand for materials, equipment and services. These operations may also provide additional local income in communities through lease payments to landholders, and if they are locally owned, through any profits these operations earn. Public revenues may also be enhanced by collection of additional property, sales, income and other taxes, or payments in lieu of taxes. These local economic benefits are in addition to the environmental, health and climate benefits wind generation may provide through the reduction of local and regional pollutants as well as reduced greenhouse gas emissions when wind generation displaces traditional fossil-fuel generation and through health and safety impacts when it displaces activities related to traditional power generation such as coal-mining (see for example Siler-Evans et al., 2013, and Cullen 2013).

Wind development also creates local costs. The wide use of space poses potential ecological challenges (see for example Leung and Yang, 2012), while the expansive land-use required by wind facilities causes changes in the landscape that may create local concerns regarding historical and cultural aesthetics. Local concerns also often arise regarding sound and visual impacts (see for example Rand and Hoen, 2017), and can affect local use of open lands. Such impacts can also affect local property values (see Hoen et al., 2015 as an example). Increased employment and economic activity caused by wind development may also increase demand for local public services, including additional emergency services, public and education services, and these increased demands may create need for additional tax revenues.

Wind taxation therefore poses a potential tradeoff between benefits and costs, and potential opposing incentives regarding taxation. Because wind development offers local economic growth opportunities, reducing the tax burden on wind development may be a policy advocated by communities wishing to attract such investment, even though local benefits of wind development are primarily private and often greatest in the short term. Alternatively, increased local public and non-pecuniary costs, and the potential externalities caused by wind development may create a reason to raise taxes on wind. When power generated from wind development is exported to more distant communities or even other states, as is often the case given the very rural nature of locations where many wind developments are sited, taxation also offers a means of "exporting taxes", or creating a compensation mechanism from the end-users of wind energy who benefit from its use to producing regions where local costs are experienced. Implementing such taxes, however, could hinder regional competitiveness to attract wind investment and undermine the ability of a region to realize the economic benefits of wind development.

Local tax environments can affect which regions successfully attract wind investment due to their effect on developer's costs. Communities have grappled with trying to decide whether to welcome large-scale wind development and whether to reduce its tax burden in an effort to competitively attract projects, or to take advantage of such development as it occurs to tax it, either to compensate for the local costs wind facilities impose, or to supplement local, county and state revenues, especially in regions where traditional revenue sources have been declining (for example, see Godby *et al.* (2018) for the case of Wyoming). Estimates of the potential tax elasticity of wind development are undeveloped in the academic and policy literatures, thus policy changes with respect to taxation often occur without any estimate of the potential impact on development. Absent such tax elasticity estimates, comparative estimates of regional wind costs and how they may be affected by tax policy would be useful to policy-makers, but such efforts are also limited in the academic literature. To our knowledge, the only effort to compare wind costs and how they vary when state tax policies are included was conducted by a private firm in 2010 (see E3 (2010)).

The following analysis attempts to estimate the impact of local state taxation and incentive policies on the cost to develop wind across the states in the Western Electricity Coordinating Council (WECC) region of the United States. The study is conducted by developing a detailed model describing the financial structure of a typical large utility-scale wind development. Again, to our knowledge, this effort is unique in the wind development literature, but as we argue, consideration of the capital structure of a wind development is crucial to understand how different taxation and other policies affect wind development incentives. Such an understanding is also necessary to develop taxation strategies that minimize competitive development tradeoffs. This analysis uses current state and federal tax laws as they were written in 2018.[2] Analysis is limited to the WECC-defined area of the United States. Given the construction of the U.S. grid, and that the WECC states all belong to the same grid area, we the region can be considered a single market area within which new wind developments could be expected to provide power for, and therefore the WECC defines a potential set of states competing with one another for wind development.[3]

In what follows, Section 1 details the potential factors determining a potential wind generation facility's profitability, including natural resource, infrastructure and market access concerns, as well as tax and non-tax considerations that may affect wind development. We also identify specific cost-factors affecting wind development and determinants of comparative state competitiveness to attract wind development in the Western interconnect. We also include an overview of differences in taxation policies by western state. Section 2 describes our modeling framework to develop comparative levelized cost estimates of wind development across states. Here we outline the specific financial capital structure we use to describe a generic wind facility that might be considered for development in each of the WECC state. Section 3 describes the scenarios we consider and the results of our analysis, how the overall tax policies of specific states affect estimated comparative costs, and how consideration of modeling efforts like ours could be used to develop policy strategies that minimize potential development and taxation tradeoffs. Section 4 offers conclusions based on our research and potential areas of future effort.

1. Determinants of Wind Facility Location and Profitability

1.1 Geographic and Resource Considerations

Potential profitability will often be a crucial consideration when considering a potential wind development site or location. The most important of these is availability of a wind resource. Not every location has good wind resources and the most important factor with respect to wind development will be the relative "windiness" of a given location. "Windiness" can be broken down into three factors: wind speed, wind variability or consistency, and wind reliability. Wind speed is critical, as this determines how often and how much power can be generated at a given site. The amount of power that can be produced at a given site is proportional to the cube of wind speed at a location, thus for a doubling of any wind speed, resulting power output will increase by a factor of eight due to the mechanical physics of wind generation, and therefore places with higher wind speeds are preferred.[4] Consistency refers to a site's ability to not only

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[2] We do include income tax changes adopted federally in 2018, though some changes in the law may also affect the investment environment for wind, an impact we do not consider specifically.

[3] While it is the case that power from states of the WECC may provide power to states in the other two electricity grids in the United States - to those states in the Eastern Interconnection, or to Texas (often referred to as ERCOT, or the Electric Reliability Council of Texas), power transfer capability from western states to these other areas is limited, and therefore for our analysis these regions are considered separate electricity market areas. While a project could feasibly be built in a WECC state to deliver power to these other regions, the additional cost of doing so could be significant (it could involve the construction of costly inverter facilities that allow power transfer to other grid areas) thus we do not consider states outside the WECC-area as direct competitors for wind development in this study.

[4] The formula to calculate the potential power of a given site is given as follows (excluding any conversion factors): $P = Cp1/2\rho AV^3$, where P = Power output, typically expressed in kilowatts, Cp = the dimensionless maximum power coefficient which reflects a specific wind turbine design's efficiency to convert wind flow into electric power (which typically ranges from 0.25 to 0.45 with a theoretical maximum = 0.59), ρ = Air density, A = the turbine rotor-blades' swept area, and V = the wind velocity. Note that the velocity factor is raised to the power of three, implying an

produce high wind speeds, but to experience them without excessive variability for longer periods of time.[5] A factor of lesser importance is air density, which can be affected by temperature and elevation. This factor is less important than ensuring conditions wind will blow and at higher speeds, but also affects power output. All else equal, sites with lower temperatures and elevations would be preferred.[6]

Table 1: Estimated Western State Land Area and Generation Wind Potential for Wind Generation Assuming Gross Capacity Factor (GCF) of 35+%

	Land Area with 35+% GCF			**Wind Capacity Potential 35+% GCF (MW)**			
State	Circa 2008 turbine technology (km^2)	2014 turbine technology (km^2)	Near future turbine technology (km^2)	Circa 2008 turbine technology (WECC Rank)	2014 turbine technology (WECC Rank)	Near future turbine technology (WECC Rank)	National Rank (2014 Technology)
MT	140,943	224,102	235,096	687,803 (1)	566,977 (1)	430,225 (1)	3
NM	69,696	166,799	221,024	340,116 (3)	422,000 (2)	404,475 (2)	8
WY	86,622	139,342	155,016	422,713 (2)	352,535 (3)	283,679 (3)	11
CO	56,220	103,904	125,845	274,353 (4)	262,878 (4)	230,297 (4)	15
AZ	349	29,413	104,352	1,703 (10)	74,414 (5)	190,964 (5)	25
ID	690	29,195	50,820	3,368 (8)	73,863 (6)	93,000 (11)	26
WA	1,309	26,700	53,137	6,386 (6)	67,551 (7)	97,241 (9)	27
OR	1,300	26,273	63,878	6,344 (7)	66,472 (8)	116,896 (7)	28
CA	3,283	25,989	57,626	16,019 (5)	65,752 (9)	105,456 (8)	29
UT	367	22,880	51,231	1,792 (9)	57,887 (10)	93,752 (10)	31
NV	313	16,996	68,351	1,526 (11)	43,000 (11)	125,083 (6)	34

Source: NREL, 2015

The quality of a given site's resource due to potential wind speeds, wind consistency and given elevation can be summarized by a site's potential gross capacity factor. The gross capacity factor (GCF) refers to the share of total potential power a specific turbine design would be expected to achieve given the wind resource in a location relative to the maximum potential power the turbine could produce if it were able to always generate at its maximum rated power. GCF does not include adjustment for reductions in output due to operational considerations or turbine interactions. When such adjustments are considered, the result is referred to as the net capacity factor (NCF). The National Renewable Laboratory (NREL) has estimated the potential land areas by state expected to produce 35 percent or greater gross capacity

equal proportional change in any of the other variables has a far lesser effect than the change in wind speed on power output.

[5] Consistency is implies not only the wind blows more often, but that it does not vary by too much, as wind turbines have minimum and maximum, or “cut-in and “cut-out” wind speeds they can produce power at due to the minimum power necessary to operate the turbine, and to protect them from damage at excessive wind speeds. Furthermore, once a turbine cuts-out due to excessive wind speed, there will be a minimum period of time before the turbine can restart and therefore produce power to protect equipment from excessive starting or stopping (referred to as high-wind hysteresis).

[6] See footnote 4.

factors for various vintages of turbine technology.[7] The results are shown for the eleven WECC states in Table 1, along with their national ranking using the most common technology deployed in wind generation today. Apparent in the table is the impact of technological improvements. Advancements in turbine technology over the last decade, and expected advancements in the near future increase the amount of developable land that achieves the 35 percent capacity factor often used as a threshold for commercial wind development.[8] The greatest potential wind resources are in the eastern states of the WECC region, and within these states (Montana, Colorado, New Mexico and Wyoming), the resources are located in the eastern portions of the state adjoining other Midwestern states, where wind-flows across the center of the country create the greatest area of potential wind capacity in the United States.

Other geographic and physical determinants can also greatly affect a potential facility's feasibility and profitability. Terrain considerations (ground slope and soil conditions for example) can affect development costs. Also, of critical importance is a site's distance from the existing regional transmission grid. Because wind developments are responsible for building infrastructure necessary to access the regional electricity grid, it can be the case that areas with lower wind resource potential are developed before those sites with higher potential due their distance from existing transmission infrastructure interconnection facilities. Hitaj (2013) shows an example of wind site locations in Wyoming, Colorado and Nebraska where developments have foregone locations with higher wind resources to be closer to the existing transmission grid to minimize such costs.

Availability of transmission capacity on the regional grid will also be crucial to site location choices as it will determine a plant's ability to develop contracts with and deliver power to valuable regional markets. Distance to such markets can also be important to minimize transmission carrying costs and power losses. Godby et al. (2018) describe relative regional differences in the value of electricity, and the relative size of markets across western states. Developers will prefer the ability to access higher value markets to maximize potential revenues a given project can generate. While not discussed specifically here, the structure of the electricity market, specifically the creation of regional transmission organizations and competitive wholesale markets has also been shown to be a determinant of wind generation outcomes (see for example Hitaj, 2013).

The interaction of technological development over time and transmission infrastructure may also play a role in determining regional wind development. Technological advances in wind generation, specifically, taller towers and longer blades developed for use in lower wind potential areas have improved potential capacity factors across states, especially, as shown in Tables 1 and 2, in states previously considered relatively less attractive for wind development, and these changes have facilitated development in what may have been previously considered marginal areas for potential development. The U.S. Department of Energy (DoE) Wind Technologies Market report (DoE, 2018) documents the convergence of capacity factors between medium, higher and highest wind resource regions. Due to technology improvements, higher productivity can now be achieved in locations considered to have worse resources. If such locations

[7] NREL (2015) assumes current wind generation technology uses towers 110m in height and current blade design technologies. Earlier technologies used 80m towers, while near future technologies assume 140m hub-heights and 110m blade diameters.

[8] Note that such technology improvements do not always increase potential wind capacity. Some newer technologies such as taller towers and longer blades reduce wind potential in states like Wyoming due to higher potential winds that would require curtailing wind output when utilizing these technologies to avoid damage to wind turbines.

are located closer to major load centers, the ability to avoid the need to develop costly transmission and other infrastructure that would be required to access more distant sites with better wind resources has changed the relative attractiveness of sites previous thought to be less desirable.

Differences in land ownership (for example public versus private) or species habitats across states may have an influence on plant location as well, as these considerations may affect permitting requirements and the number of separate jurisdictions a project must satisfy in permitting processes. Such considerations can directly influence not only the cost of the project, but also the timeline to development and eventual revenues, and such concerns have been document not only for wind, but other traditional energy resources.[9] Considering all the potential combinations of resource, terrain, transmission infrastructure and regulatory conditions – the decision to locate a particular project in a particular state is complex and often project and place specific. All western states have locations suitable for economically competitive wind development given resource, technology and infrastructure access opportunities across the west. In this environment, the competitiveness of a state to attract wind development may therefore be critically affected by state policy choices that incentivize or disincentivize such activity. Such incentives can serve to reduce (or increase) wind generation owner's costs and may be used to overcome potential resource, access and infrastructure challenges as states compete to attract wind development.

1.2 Federal and State Policy Incentives

Beyond the existence of a wind resource and access to markets for a plant's output, state and national policy factors play a critical role in a potential wind facility's profitability. Such programs may *directly* or *indirectly* affect a wind facility's profitability. Here, we define programs that *directly* affect profitability as those programs that affect the costs (supply-side effects) of a wind facility. *Indirect* incentive programs refer to programs that may affect the demand for wind energy (demand-side effects), and therefore affect profitability through potentially more favorable power purchase agreements. The following list is not comprehensive but includes the most important policies at the state and federal level affecting wind facilities' costs and demand, especially in western states in the WECC area. While the focus of this paper is on the impact state's direct incentives may have on the cost of wind energy, indirect and direct factors at the state and federal levels are included because, like geographic and resource considerations, they play an important role in wind developer's location choices.

1.2.1 Federal Programs Indirectly Affecting Profitability.

The oldest federal policy that has indirectly incentivized wind development in the west has been the Public Utility Regulatory Policies Act of 1978 (PURPA). Currently this regulation only affects regulated utility markets, and not those that have been restructured to include competitive wholesale markets. PURPA requires regulated utilities to accept power generated from qualifying facilities including wind farms that are typically 80 MW in capacity or less, at the utility's avoided cost of energy. These contracts are usually 20 years in length unless modified by state law. Avoided cost rates are approved by state regulators. Such rules have historically allowed wind developers to identify a captive customer for their power under a long-term contract, eliminating significant uncertainty regarding future power purchase agreements and rates they would otherwise have to negotiate over the lifetime of a wind farm, typically 20-years. This program has spurred significant wind development nationally since its inception, and continues to

[9] We presume that regulatory costs may also differ due to variation in environmental, cultural or historic preservation concerns present within each state.

influence wind development in states where regulated utility markets still exist. In the west, this currently includes all WECC states but California, which restructured its electricity market in 1998.

1.2.1 Federal Programs Directly Affecting Profitability.

Federally, since 1978, an investment tax credit (ITC) program has been available for wind developers, while the production tax credit (PTC) was created in 1992.[10] All states have access to federal incentives, and the most influential of these has historically been the renewable energy production tax credit (PTC). First instituted as part of the Energy Policy Act of 1992, these inflation-adjusted tax credits were originally worth $0.015 ($15 per MWh) in 1993 for each kWh of qualifying renewable production. Project eligibility for the tax credit is based on the year a project begins construction.[11] Since its inception, this program has been renewed eleven times and has expired six times during this period. The program's importance to the wind industry is apparent when observing how yearly additions of wind capacity have varied in a boom-bust cycle with the availability or expiration of federal PTC's (for example, see DoE 2015, Chapter 2, p. 19). In 2015, legislation extended the PTC program for wind energy and retained the credit, then worth $0.023 per kWh, but began a phaseout of the program, starting in 2017. The program was reaffirmed in 2018 after a one-month expiration of the law (see Sherlock, 2018).

The federal PTC program is often misunderstood. The tax credit is non-refundable, thus the user of the tax credit can only apply credits earned from renewable energy production against existing tax liabilities and cannot claim any excess value as a refund. As is shown in the following section, wind developers often have very little federal income tax liability due to the deductibility of interest paid on debt used to finance the large capital costs involved, capital depreciation cost deductions, and the allowance to carry forward operating losses from previous years against taxes owed. For this reason, the primary value of the federal PTC program has not been the reduction in income taxes payable by wind developers, but ability to use such credits to facilitate tax-equity financing of wind facilities. Tax-equity financing involves selling future tax credits to investors, who in return provide capital funding for wind projects, thus the value of the program has primarily been to reduce the cost of project financing for wind developers. As is shown in

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[10] The Federal Business Energy Investment Tax Credit (ITC) program (26 USC § 48) allows large wind projects (turbines over 100 kW) to apply for a tax rebate based on the value of equipment. The current law allowed a 30% rebate for projects beginning construction prior to the end of 2016, and the credit rate falls by 6% per year until 2019 when it will allow a 12% rebate. After 2019 the credit will no longer be available for large turbines. The Federal Renewable Electricity Production Tax Credit, first enacted in 1992, under current law allowed a credit against federal taxes of $23/MWh of production to be earned in 2016. This credit is reduced in 20% increments and adjusted for inflation from the 2016 value through the years 2017, 2018 and 2019 before ending in 2020, with projects begun in 2019 required to be online by 2021 to avoid risking the loss of the credit. [10] In 2017, the PTC was valued at 0.019 per kWh. In 2018, the credit declined to 0.014 per kWh. 2019 rates had not been published as of the writing of this report. Assuming no increase in the base rate used for inflation, the value for projects beginning construction in 2019 would be $0.010 per kWh, and $0.000 per kWh in 2020, assuming no further extensions. The production credit lasts for 10 years from the start of commercial operations.

[11] In 2013, the Internal Revenue Service began publishing guidance regarding how it evaluates when a project has "commenced construction" to determine eligibility for PTCs. This was especially in years when the credit was expiring to eliminate uncertainty regarding project edibility. These requirements can either be fulfilled by beginning "physical work of a significant nature," or by earning "safe harbor" by demonstrating that 5 percent or more of the total cost of the facility has been incurred. Both criteria require continuous progress towards completion.

the model developed, the actual value of tax credits to developers is usually less than the face-value of the credits created in a given year.

1.2.3 State Programs Indirectly Affecting Profitability.

At the state level, several types of incentive programs exist and can indirectly affect wind developer's profitability. These policies primarily come in the form of mandates to provide renewable energy to consumers, the most common being a renewable portfolio standard (RPS). Such RPS programs incentivize the development of wind facilities by requiring a certain share of electricity consumed within a state to come from renewable sources; and impose a financial penalty on utilities that do not meet these requirements.[12] Such rules create demand for wind developer's output and create opportunities for wind developers to enter into long-term power production agreements. While local utilities may purchase in-state or out-of-state renewable power, often within such regulations a preference may be given to power generated within the state's borders, or even specific sites within a state's borders.[13] RPS policies have been shown to help drive demand for wind energy development, especially within states adopting such rules (see Black *et al*., 2014; Hitaj, 2013; Carley, 2009; Adalaja and Hailu, 2007; and Menz and Vachon, 2006). Only three states in the WECC do not have an RPS standard: Wyoming, Idaho and Utah.[14]

State policy can also indirectly affect wind project profitability through modification to rules governing PURPA-qualifying facilities. Specifically, states may modify or adjust avoided cost rates through their regulatory oversight. For example, state regulators may approve avoided cost schedules that are more or less favorable to renewable energy developers, and may include integration costs in avoided cost schedules.[15] States may also reduce the length of time that PURPA contracts are binding. For example, in 2015, Idaho reduced the length of PURPA contracts from 20 years to two, while in 2017 Montana increased its PURPA contracts by five years to 15 years in length. States have even modified the size of facilities that may be considered as qualifying under PURPA. For example, Idaho has used this power in the past to reduce the size of PURPA-qualifying facilities to below the size of a commercial wind turbine to control the number of qualifying facilities that were being developed in the state (see Black et al., 2014).

Finally, state policy may indirectly affect wind project profitability by implementing "retail electricity choice." In such programs, consumers may choose their source of supply and can therefore affect the demand for wind energy. As of 2017, thirteen states had such programs, including two in the WECC (NREL, 2017). Both western states have limited retail choice. In Oregon it is limited to large commercial and industrial consumers, while in California it is limited to large users, or to consumers that belong to

[12] Iowa was the first state to create an RPS in 1983, and as of 2018 ranks third in the country in total installed wind capacity.

[13] For example, North Carolina offered triple credit toward their RPS standard for the first 20 MW of renewable energy capacity installed in specific cleanfield locations. Lips (2012) notes "most states do try to keep the benefits within their borders. Although RPS policies are generally crafted to avoid conflicts with the dormant Commerce Clause, nearly all credit multipliers require systems to be installed within the state to qualify. In some cases, this is stated explicitly. In other cases, it is stated implicitly by requiring systems to serve a customer's on-site load, or be connected to the distribution system of an electric cooperative or municipal utility." (Lips (2018), pp. 8-9).

[14] While not having an RPS standard, in 2008 Utah established a voluntary renewable portfolio goal of 20% by 2025.

[15] Integration costs refer to the costs charged by utilities to renewable generators to ensure resources are available to balance their systems when the wind power is unavailable.

community-choice aggregators (CCA's) that allow customers in some cities and counties where they have been organized to procure alternative sources of energy beyond their local suppliers.

1.2.3 State Programs Directly Affecting Profitability.

States also offer a variety of incentives, credits and exemptions that directly affect wind power development, which is the focus of the modeling presented in this paper. These programs can directly affect a wind facility's profitability, and can come in the form of production incentives offering cash payments based on the amount of electricity output, tax credits that may be refundable or non-refundable, or exemptions (partial or full) from state and local taxes. They may also come in the form of payment in lieu of taxes (PILOT) programs. In addition to tax reductions or exemptions, because different states have different tax rates for income, business, sale or property taxes, tax rate differentials can also be wind development incentives if they reduce a project's taxes payable relative to locating in another state.

In the WECC states production incentives have historically been offered.[16] Table 2 summarizes the tax rates and exemptions available among WECC states. Utah is the only western state currently offering a state production tax credit, granting a $3.50 per MWh refundable production tax credit in the first four years of production. Wyoming includes a less common form of tax (dis)incentive policy, utilizing a wind-specific generation tax additional to all other taxes that is unique nationally, charging $1/MWh of wind-generated electricity.[17] From the table it becomes clear how different tax regimes can be across states. For example, three states (Wyoming, Nevada and Washington) do not have corporate income taxes, while Nevada and Washington instead assess a gross receipts tax. Furthermore, six states as shown in Table 2 have exemptions from corporate income and business taxes applicable to wind development.

With respect to sales taxes, two states (Montana and Oregon) do not assess sales taxes, while five additional states have sales tax exemptions available for wind energy including three that entirely exempt wind from sales taxes (Colorado and Utah, while New Mexico is exempt if it pays state gross receipts taxes). Additionally, county or local sales taxes can differ from the state level thus the tax cost within a state can depend on the county development occurs in. Table 2 shows both the state and average local rates of sales taxes, where they are charged.

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[16] Hitaj (2013) lists several at the time of writing that no longer are offered. Some incentives in western states will end soon, or have reached their funding cap. For example, Arizona offers a $0.01 per kWh a production tax credit, but this ends in 2019. New Mexico offers the same tax credit but limits it to the first 400,000 MWh of production and capped total credits at $20 million. The program is fully subscribed thus new facilities cannot access this credit.

[17] Technically, Wyoming is not the only state in the nation with a wind generation tax. Minnesota assesses a $1.20 per MWh generation tax on wind facilities larger than 12 MW in capacity, however, the tax is imposed in lieu of assessing property taxes on the improved value of the land. For a discussion of this tax and tax conditions specific to wind in Wyoming, see Godby *et al*. (2018)

Table 2: Summary of Wind Taxes and Incentives by Western State

	State Corporate Income Tax Rate	State Gross Receipts/ Business Tax Rate	Exemptions from Corporate or Business Taxes	Sales Tax Rate (Avg. state & local)	Sales Tax Exemption	Property Tax Rate and Assessment Method	Property Tax Exemption/ Incentive	Depreciation Method	Other Incentives/ Subsidies	Specific Wind Taxes
Arizona	6.968%	N.A.	-investment tax credit of 10%, 1¢/kWh Production tax credit, ends 2019.	5.6% (8.25%)	No	-assessment based on 18% of depreciated facility value, taxed at 12.95% (state average)	-wind equipment full cash value assessment discounted by 80%	Straightline, 25-year, 10% floor.	No	No
California	8.84%	N.A.	No	7.5% (8.48%)	-limited to non-generation equipment	- 1% tax rate on depreciated facility value	No	Straightline, 20-year, 20% floor.	No	No
Colorado	4.63%	N.A.	-80% exemption for facilities in state enterprise zones	2.9% (7.5%)	-state sales tax exemption for wind facilities	- assessment based on 29% of state-adjusted expected gross revenue, taxed at 7.555%	-graduated reductions in property tax assessment for larger facilities	Straightline, 20-year, 15% floor.	No	No
Idaho	7.40%	N.A.	No	0% (6.04%)	No	-1.67% tax rate on depreciated facility value	-can elect to be charged 3% of annual energy earnings if not regulated by IPUC	Straightline, 20-year, 20% floor.	request financing from Idaho Energy Resources Authority	No
Montana	6.75%	N.A.	-35% investment tax credit (cannot be taken with property tax exemption), 1% of new wage payroll if jobs increase by 30%	N.A.	-no sales tax in the state	-assessment based on 3% of depreciated facility value, taxed at 55.546% (state average)	-discount of 25% or 50% of assessed value in first 5 years, discount declines in equal increments over	Straightline, 20-year, 15% floor.	No	No
Nevada	N.A.	-0.136% of Nevada gross revenue exceeding $4 million	-Revenues from power exported from the state would be exempt	6.85% (7.98%)	-reduced to 2.6% on purchases in the first three years of operation	-assessment based on 35% of depreciated facility value, taxed at 3.15% (state average)	-over 10 MW, the property tax is reduced by up to 55% for up to 20 years	Straightline, 50-year, 0% floor.	No	No
New Mexico	7.60%	State: 5.125% Average across all tax areas: 6.425%	-$0.01/kWh credit up to the first 400,000 MWh produced before $20 million cap was met	5.13% (7.55%)	Exempt from state sales tax through payment of gross receipts tax	-assessment based on 33.33% of depreciated facility value, taxed at 2.6666% (state average)	-taxes fully negotiable if industrial revenue bonding used	Straightline, at 3.2% rate down to 20% floor.	-local industrial revenue bonding may be negotiated.	No
Oregon	6.60%	N.A.	No	N.A.	-no sales tax in the state	-assessment based on depreciated facility value, taxed at 1.5%	-may qualify for permanent 20% reduction in assessed value	Straightline, 20-year, 20% floor.	No	No
Utah	5.00%		-10% investment tax credit or $3.50/MWh refundable production tax credit in first four years	5.95% (6.76%)	-renewable energy equipment is exempt	-assessment based on depreciated facility value, taxed at 1.3%	- abatement of some or all property taxes for projects within renewable energy development zones	Straightline, 20-year, 20% floor.	No	No
Washington	N.A.	-0.484% of gross receipts	No	6.5% (8.9%)	No	-assessment based on depreciated facility value, taxed at 1.225%	No	27-year state-specific table, 15% floor	No	No
Wyoming	N.A.	N.A.	-no taxes on income or earnings	4% (5.4%)	No	-assessment based on 11.5% of depreciated facility value, taxed at 6.8% (state average)	No	Straightline, 20-year, 20% floor.	No	$1/MWh

Property taxes similarly differ by county and state, and are affected by state-specific exemption policies. How incentives are applied to property taxes can also differ. For example, calculation of property taxes on wind facilities may differ from other forms of property, both with respect to the assessed value, and with respect to the depreciation allowed, which can also reduce taxes payable. Only four states in the WECC treat property taxes on wind development as they would on any other utility property – California, Utah, Washington and Wyoming, although Utah may reduce property taxes if development is located in a renewable energy development zone.[18] Seven WECC states offer full or partial reductions in their property tax rates for wind. These come in various forms. Arizona and Montana have reduced tax rates on wind energy relative to other generating facilities. Colorado attempts to create parity with fossil-fuel facilities by creating a tax factor that adjusts for the greater capital intensity of wind facilities based on a revenue approach. Oregon, Nevada and New Mexico have negotiated property tax relief.

Other financial incentives are also available in two WECC states. Idaho offers financing support from independent power producers that are not regulated by its Public Utilities Commission. Because almost all wind entities in the state are regulated, however, this incentive is not relevant to most projects. New Mexico similarly offers financing options not available in other states by allowing counties to finance large capital-intensive projects, including wind facilities, using an industrial revenue bonds. This scheme allows the local county to own the project and finance it through its own bonding, and then lease the project back to the developer, thus allowing the developer to access financing through non-traditional means.[19] Furthermore, the use of such a program makes the county effectively a part owner in the project and because counties are tax-exempt entities, potentially reduces the tax burden a project may face. Projects utilizing such funding, therefore, must negotiate property and/or county sales taxes payable on the project on a case by case basis. This implies the true benefits to the developer for using such a program depend on the negotiated payments. We refer to this as a form of incentive as a *payment in lieu of taxes* (PILOT) program. Other more straightforward PILOT programs may also exist though we did not document any that appear to systematically affect wind development in the west.[20]

Overall, while tax incentives are important to wind developers due to their effect the potential cost of the project, some taxes and incentives will be more important than others due to their impact on overall project costs and the timing of these costs. For example, wind facilities are highly capital intensive, thus sales tax incentives, which avoid tax liabilities primarily during construction and at the start of a project life, can affect the net present cost of a project significantly more than identical tax cost reductions occurring at later in time. Furthermore, since most sales tax costs occur before projects begin earning revenue, the tax costs will often be financed, along with capital and construction costs, thus the resulting cost to project owners for a given sales tax will be greater than the initial taxes charged. Similarly, states like New Mexico may offer financing assistance incentives that will affect project financing costs and therefore can have a greater impact on total developer costs than property or income tax reductions, which do not require financing and that occur after a project is completed.

[18] We could find no example of this and so treat property taxes in Utah similarly to any utility property.
[19] Such financing may also allow a lower cost of debt as it is issued by a county or municipal agency.
[20] The simplest form of a PILOT program would allow a firm to pay for a state service directly in lieu of taxes. Implementing such programs requires states to allow counties some autonomy in taxation or bonding, an opportunity that also differs across states.

2. Assessment of the Impact of Tax Differences on Wind Project Profitability and Development

2.1 Previous Literature

Optimally, states considering taxation changes on wind development with an eye toward and economic development would understand how different incentive and taxation decisions affect wind development costs and location decisions, and how relative differences in tax policies between states may create advantage or disadvantage. Assessment of the impact of differences in tax policy across states on wind development is difficult to accomplish because many states do not assess taxes in comparable ways. Estimates of the potential tax elasticity of wind development are undeveloped in the academic and policy literatures. Even estimates of how state policies generally affect wind development relative to other policies are underdeveloped in the literature, and at times contradictory.

Research on how tax and other incentive policies impact wind generation development is well into its second decade and spans several methodologies. In perhaps the earliest academic study to consider policy impacts on commercial scale wind development, Bird et al. (2005) used a qualitative review of wind development outcomes in twelve states spanning the eastern and western United States to identify the most effective policies to spur wind development. With respect to state policies, they concluded RPS standards appear to have the most influence. They also found that financial incentives, including both incentives that affect financing costs such as investment funds, or production incentives were important drivers of wind development. Property and sales tax exemptions were also found to be influential, though they conclude that by themselves they may not be capable of stimulating new wind development, potentially implying that other policies may be more effective. They also cautioned that the tradeoff between attracting economic development and preserving local tax revenues should be considered, especially in rural areas.

In the first attempt to quantify the relative effectiveness of state policy options, Menz and Vachon (2006) used an econometric analysis to determine the relative importance of state policies in attracting wind development across 39 states. Their findings supported previous studies that RPS standards appear to be most effective, and that allowing retail choice could also be influential. In contrast to previous results though, they found public benefits funding was not a significant influence in developing wind generation. Their public benefits fund variable, however, was a catch-all of all state financial incentives programs, and it could not be used to discern the effects of specific state financial incentives.[21] Other authors have also noted that these results were constrained by data limitations and omitted variable bias, and low sample size likely undermined the statistical validity of the results (Carley, 2009).

Hitaj (2013) attempts to address the statistical challenges of identifying the drivers of wind power development using several alternative econometric methods to quantify the relative importance of resource, transmission access, market structure and federal and state renewable energy incentives using a detailed national dataset from 1998 to 2007. Her results identify the most statistically significant effects on wind capacity additions at the county level nationally, and from these results she is able to create

[21] Menz and Vachon admit the insignificance of their public benefits fund variable could be due to the fact it only considered states that have created such funds from levies on consumer electric bills, and that it also excluded California. They also note such funds have been used not only to create supply-side financial incentives for renewable energy, but also have been used for demand-side efforts, and have been used for more than just wind technologies.

estimates regarding the most cost-effective state financial incentive policies. Findings from this work suggest that among the choices a state may have with respect to financial incentives, corporate tax credits (income and business tax) and sales tax incentives, as well as production incentives have positive and significant impact on wind capacity additions, while property tax incentives appear to have no or even negative effects. Her results also indicated that while on average, sales and corporate tax credit had very similar impacts on wind capacity increases per dollar spent nationally, production incentives were approximately 2.5 times more cost-effective.[22] A disadvantage in this paper of the aggregate econometric approach with respect to state policy, is that while it identifies average impacts for generic policy choices on wind development nationally, it does not address how a policy change in one state could affect wind development patterns in a sub-region of states, for example in the WECC area, or among a sub-group of states within the WECC area that may compete for the same wind development.

An alternative approach to aggregate conclusions regarding the impact on wind development outcomes and effectiveness of tax incentives based on case studies or econometric methods is a direct calculation of incentive benefits to wind facilities for different state tax and incentive strategies. This can be referred to as a "bottom-up" approach. Estimates of project cost directly assess how state incentive policies affect the profitability of a wind development for a given state. In the academic literature, Haggerty et al. (2014) develop partial estimates of property tax impacts on an identical wind farm across seventeen counties in the WECC area, with representation from each of the eleven WECC states. While their focus is not on the costs to wind developments for different regimes across counties and states, their results describe how differences in tax policy affect the tax revenues (and therefore tax costs) in each location. The results, however, give an incomplete picture of wind facility profitability for a location choice in any of their seventeen sites. The authors do not attempt to develop full comparative facility cost estimates that include the collective impact of any other incentives, differences in regional construction costs, or wind resource differences on the profitability of any specific location.

To our knowledge, the only effort to develop wind facility costs across the eleven WECC states, including how they vary when state tax policies are included, was conducted by a private firm in 2010 on behalf of the State of Wyoming (see E3, 2010). This study developed levelized cost estimates across all eleven states after state incentives were included. This study, however, is out of date and did not include state policies now in place. Furthermore, the development of the levelized costs in that study were somewhat different from the cost methodologies used by NREL or Lazard for example, and assumptions regarding relative state wind resources and cost differences have changed.

Given the fact that there are no recent studies estimating the impact of state incentive policy changes on wind development, the following describes a modeling effort to address this gap. The approach used attempts to assess how state incentives affect the relative attractiveness of the eleven WECC states by deriving comparative estimates of wind facility cost in each state. The bottom-up approach allows the computation of a levelized cost estimate of wind energy across states for an identical facility across states. The methodology also allows decomposition of the various components of cost at a wind facility, including capital, operating, and financing costs, as well as the cost of federal and state taxes to determine how the

[22] In this work, corporate tax credits were applied per dollar of capital spent as a deduction against taxes owed, while production tax credits were assumed to produce firm revenues (or reduced costs) thus the cost-effectiveness calculation in this paper would be most consistent with a refundable state tax credit or direct production payment incentive.

relative competitiveness of each state is affected by state policy given regional cost differences and resource quality assumptions.

2.2 Modeling Framework

The cost of wind development will clearly be affected by tax and other financial incentives because they affect the costs, profitability and expected returns from any wind project. For this reason, states may wish to be cognizant of the impact state-specific tax policy decisions could have on the comparative cost of wind projects developed within their borders relative to costs in other states. While cost is not the only factor affecting a location decision, it is one that states can influence using incentives.

The most commonly used metric of cost is the computation of the *levelized cost of energy*, or LCOE. In its simplest form, the LCOE combines all costs over the design lifetime of the generator to compute the average cost of each unit of electricity produced as a single number (expressed in dollars per megawatt hour, or $/MWh). Since costs occur at different points in time, a net present value is used for future costs and output, discounting at a given rate.[23] LCOE has historically been used as a proxy for the average revenue a generator must earn over its lifetime to breakeven and has been used and an indicator of the economic competitiveness of alternative generation choices. While LCOE has been the most commonly used metric to evaluate the cost of electricity from different sources for decades, it is not a perfect measure and has been criticized both for being too simple in concept, and because of its sensitivity to specific assumptions. Despite these criticisms, we use a variant of the measure in what follows, making clear the assumptions made to avoid any loss in transparency.[24]

In the analysis that follows we develop a levelized cost estimate, which we refer to as the *average cost of energy* (ACOE) across each of the eleven WECC states for specific wind facility whose characteristics are held constant throughout the analysis.[25] All dollar values are expressed in current dollar terms (unadjusted for inflation). Tax and incentive differences across states, as well as wind resource and regional cost differences are then used to show they affect the computed breakeven cost, and therefore the relative competitiveness of states to attract wind energy. Because estimates of cost across states use common assumptions and identical technology, we argue most criticisms of such levelized cost estimates do not apply.[26] Given the motivation of this work – comparison of state costs - we focus on relative differences between states and not the absolute values of cost presented. Given the difference between our

[23] See https://energyeducation.ca/encyclopedia/Levelized_cost_of_energy for a simple example of the levelized cost calculation. The discount rate used depends on the application. Typically, this will be set at the expected rate of return, or rate of interest paid on debt.

[24] Common criticisms of any levelized cost estimate include the fact that it does not distinguish between capital, fixed and marginal costs, results are sensitive to interest rates used and assumed project lifetimes, such measures ignore project or technology-specific risk factors and externalities, and that the metric usually ignores any integration costs. Joskow (2011) notes that comparisons of intermittent technologies like wind generation to traditional dispatchable technologies, though commonly used, are misleading because the value of electricity produced varies over time as well as for reasons noted above.

[25] We refer to the measures as “average cost of energy” because we do not apply discounting to maximize the transparency of the results. We do not refer to our measure as a the levelized cost to avoid confusion as we discuss in the text.

[26] We admit that cost estimates presented overlook time of day or seasonal generation profiles that could affect the relative value of generation across states or locations.

computation methods and others presented in the literature or by industry, absolute cost estimates are also not directly comparable to those presented elsewhere.

2.3 Computing the Average Cost of Energy across WECC States

The following describes in detail how cost estimates used to compare the impact of state incentives on wind energy costs across western states were computed. An advantage of a detailed cost calculation like that presented below is that it requires a specific description of the financing of a wind development, often referred to as its *capital structure*. As will become clear in the analysis and often overlooked or treated too simply in common measures of LCOE in the literature, the assumed capital structure is critically important in identifying how capital costs change with interest rate assumptions. The capital structure of a wind facility is also affected by the types of incentives states offer. Modeling costs in detail allows an understanding of how potential incentives such as tax credits and exemptions affect costs not only through the direct tax cost, but also potentially through other avenues such as financed costs. A clear description of a project's capital structure is therefore necessary to understand how incentives affect project costs and how different incentives may be preferred to others by wind developers.

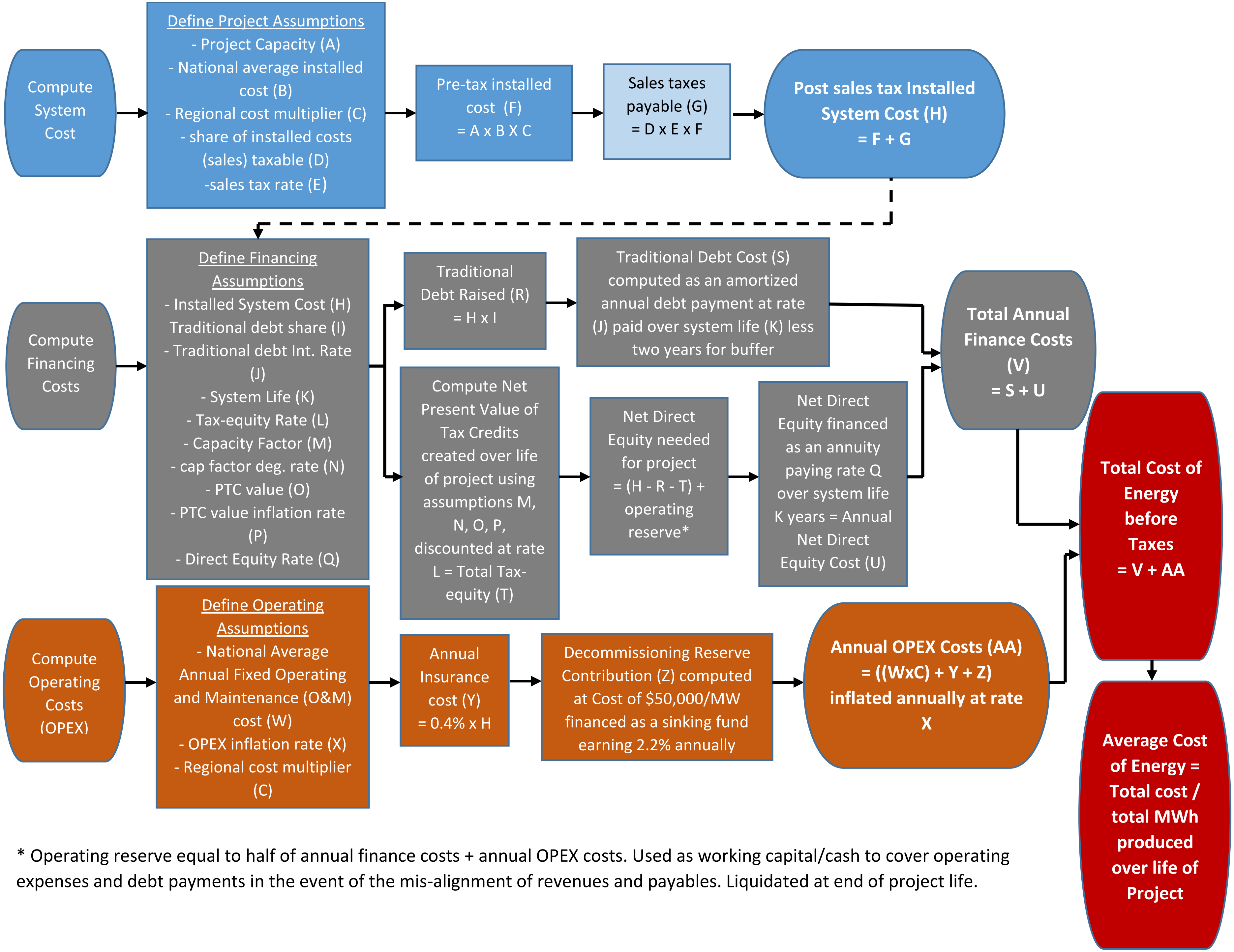
Figure 3 describes how we develop the average costs of energy presented here (ACOE). Developing the ACOE for each state begins with defining the system cost of the assumed project. We assume an identical 300 MW project is considered in each of the eleven states in the WECC. For simplicity, we do not consider costs regarding any additional transmission or integration costs necessary to connect the project to the regional electricity grid, costs that may or may not be the responsibility of the project developer. The system cost of a project is determined by the assumed overnight cost of the project – the cost of capital and its construction and installation costs. For the purposes of the analysis presented, an overnight cost of $1610 per kW is assumed, the average cost of capital nationally in 2017 (DOE, 2018). The overnight cost is then adjusted for any regional cost differences. We use the U.S. Army Corps of Engineers Civil Works Construction Cost index (USACE, 2018) to define WECC differences in overnight costs accounting for regional differences. The USACE state multipliers used are described in Table 3.

Table 3: State Cost Adjustment Factors

State	**Cost Adjustment Factor** (1.00 = National Average)
AZ	0.96
CA	1.22
CO	0.94
ID	0.98
MT	0.96
NM	0.92
NV	1.04
OR	1.05
UT	0.96
WA	1.06
WY	0.94

Source: USACE (2017)

Figure 3: Process of Computing Average Cost of Energy Computation before Income and Wind Taxes



* Operating reserve equal to half of annual finance costs + annual OPEX costs. Used as working capital/cash to cover operating expenses and debt payments in the event of the mis-alignment of revenues and payables. Liquidated at end of project life.

Computation of system costs is also affected by sales taxes, since sales taxes are primarily paid during procurement and construction. Note that the share of system costs taxable will affect the estimated impact of sales taxes on a developer's costs. Hitaj (2013) presumes all system costs are taxable. Not all system costs, however, may be taxable as some purchases may occur in other states or be exempt under state law. Here, a conservative estimate of two thirds of system costs being is used.

Once system costs are known, financing costs are computed. We assume a specific share of total system costs are financed by traditional debt. An amortized payment is then computed based on the assumed traditional debt interest rate. The term on this debt is assumed to be two years less than the assumed system life of the project, allowing for a common industry practice of creating a two-year buffer on such debt. The remaining system costs are then financed by a combination of tax-equity, financed using estimated federal production tax credits the project will earn, and direct equity. The amount of tax-equity sold is computed by calculating the expected production tax credits the plant is expected to create over its lifetime (plant capacity x state-specific capacity factor x any assumed degradation of that capacity factor over time x value of the tax credits). The net present value of these credits is then determined, discounting at the assumed tax-equity rate of return. Tax credits are then assumed sold at this value to raise the tax-equity portion of the project financing. Any remaining project financing (system costs minus traditional debt raised minus tax-equity raised) is then assumed to be funded by direct equity at an assumed internal rate of return.[27] The sum of finance payments on traditional debt and direct equity are then used to define the total annual finance costs of the project. The values assumed describing the share financed costs using traditional debt, rates of return for traditional debt, tax-equity and direct equity, and the life of the project necessary to compute cost estimates are summarized in Table 5

As shown in Figure 3, state-specific annual operating costs (OPEX) costs are computed as the sum of annual O&M costs, the annual costs of financing a sinking fund to cover assumed decommissioning costs, and the annual costs of insurance. The average cost of energy before taxes expressed in $/MWh is then computed by summing total annual operating and finance costs over the life of the project and dividing by the expected lifetime electricity production of the facility using capacity, capacity factor and production degradation assumptions.[28] The resulting computation is the pre-tax breakeven annual cost per MWh of output necessary to create the assumed rate of return on direct equity while covering all other costs.

The cost methodology outlined here is like that used for industry estimates of levelized cost presented in Lazard (2018), however our degree of detail used to model costs is greater. Industry estimates typically do not assume a buffer in the payment of traditional debt nor do they usually include insurance costs, decommissioning costs and tax impacts on financed costs. Furthermore, "unsubsidized" estimates like those in Lazard (2018) ignore the impact of tax-equity financing utilizing the federal PTC. All assumptions used to calculate the cost estimates presented here are described in Table 4. Values were derived using government and industry sources like DoE (2018), and where estimates could not be found we used expert solicitation. Tax rates and practices by state were defined using information summarized in Table 2.

[27] We assume direct equity is financed as an annuity payable over the life of the project and returning the rate of return on direct equity rate assumed.

[28] In a traditional levelized cost computation the costs and production of the facility in each year would be discounted using an assumed discount rate, with the quotient of these net present values defining the project LCOE. We ignore discounting for the sake of transparency and clarity as only comparative costs matter in the analysis presented.

Figure 4: Property and Wind Tax Cost Computation Processes

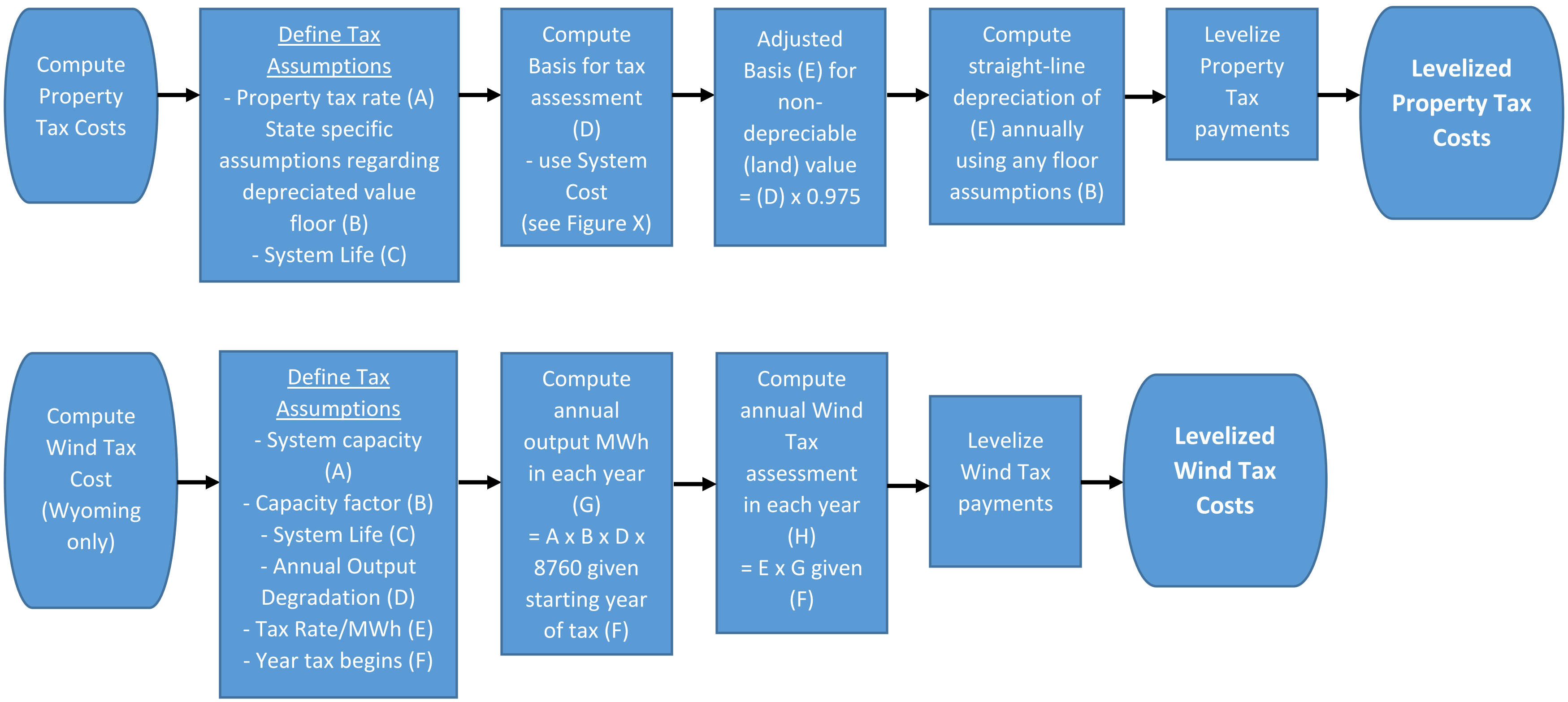


Figure 5: Income Tax Cost (Federal and State) Computation

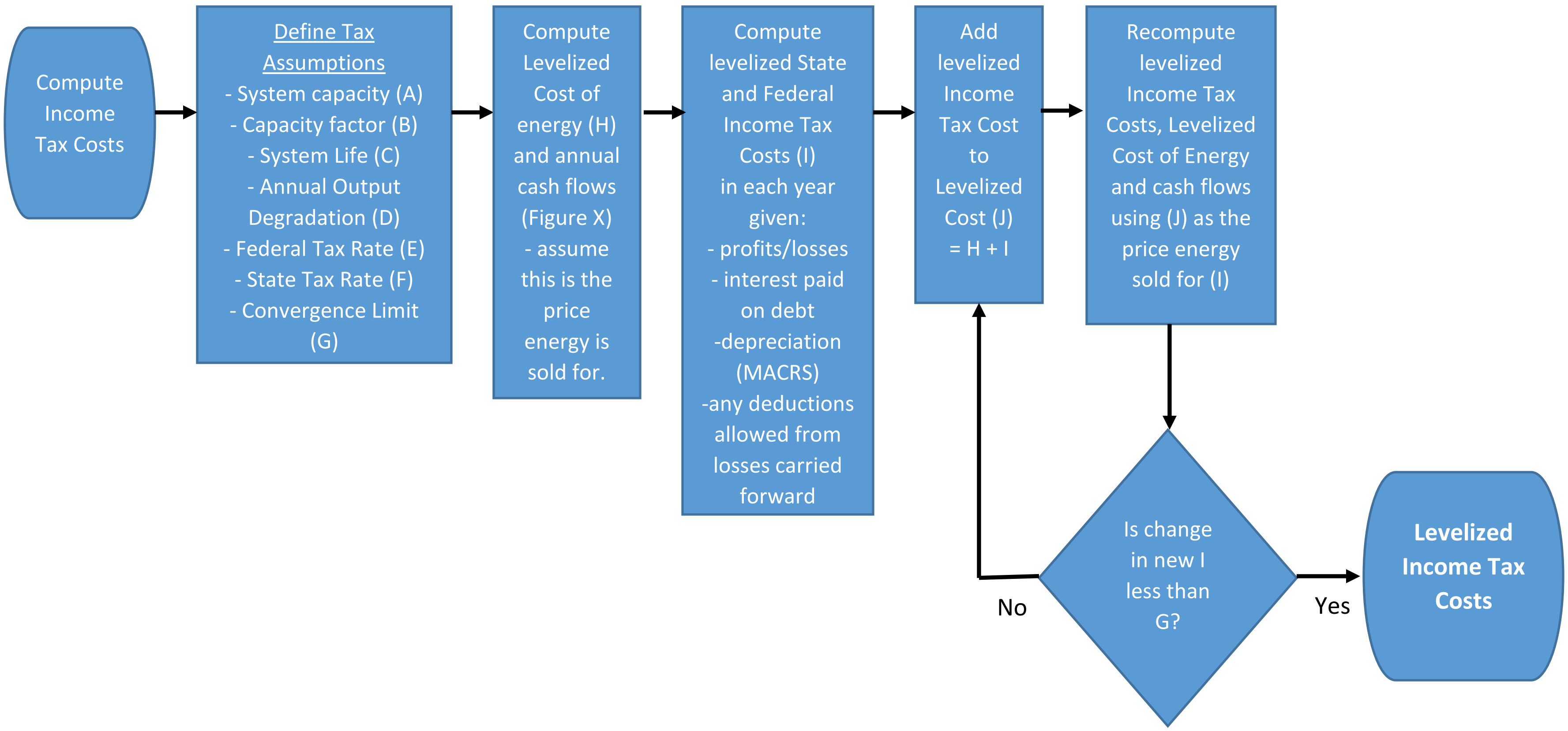


Figure 6: Gross Receipts Tax Cost Computation

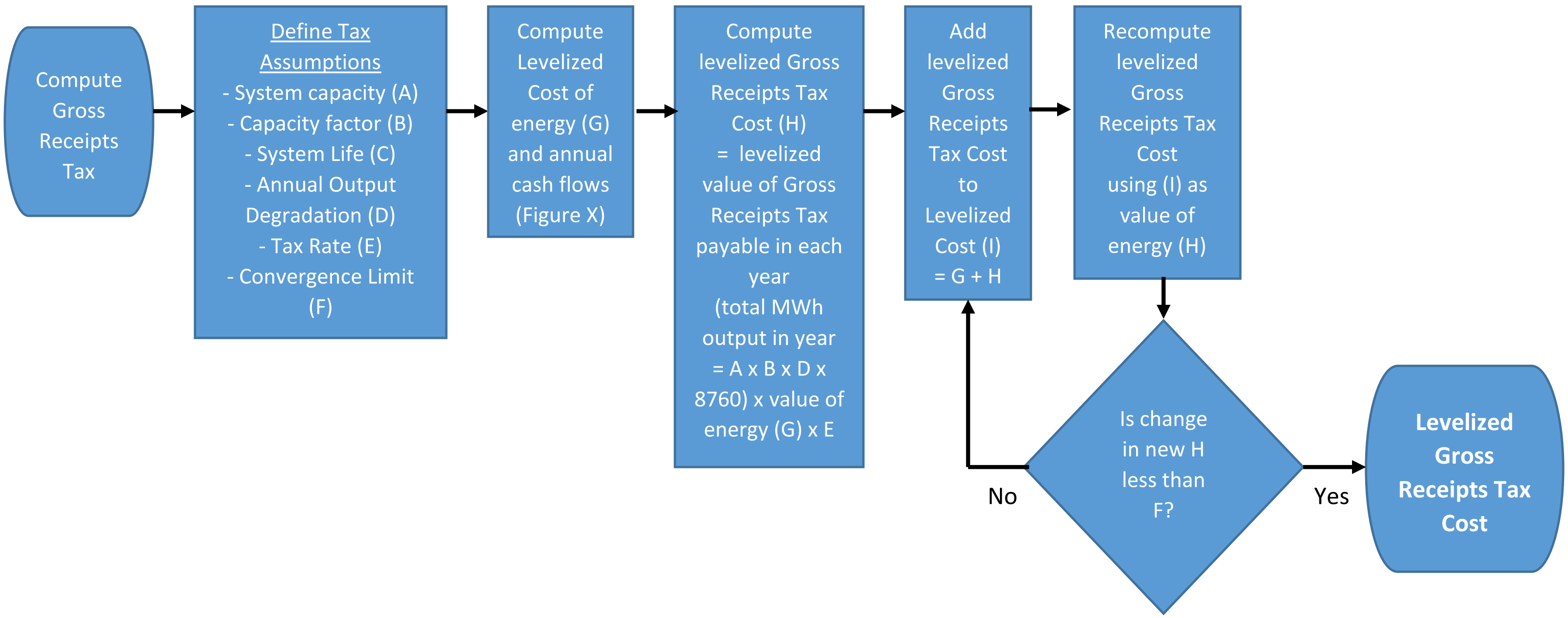


Table 4: Cost of Energy Calculation Assumptions

Cost Factor	Assumed Value
Output Capacity	300 MW
Total Cap costs*	1610 $/MW
Share of System Costs subject to sales tax	67%
Fixed O&M Annual Cost	28 $/kW
Fixed O&M inflation	1.5%
Variable Cost	0
Cap Factor degradation rate	1%
Construction time	12 months
Facility Life	20 years
Share of Financing using traditional debt	50%
Cost of Debt	6%
Cost of Tax-Equity	8.5%
Cost of Direct Equity	10%
Year of construction start	2018
Year of operation start	2019
Federal PTC value	19 $/MWh
PTC inflation	1.1%

Sources: DoE (2018), and expert solicitation. Values are in current dollars.

Once pre-tax ACOE is determined, property and production taxes (Wyoming only) were computed. Annual property taxes were estimated for each state based on the state-specific tax rules summarized in Table 2. Total taxes paid over the life of the project were then computed and converted to a per MWh cost. In the case of Wyoming, the production tax was assessed as a charge per MWh of electricity produced in each year using estimated electricity output in that year derived from the project capacity, state capacity factor, and degradation assumptions. After these taxes were computed, property and production taxes were added to the pre-tax ACOE value. The computations for property and production taxes are described in Figure 4.

Figures 5 and 6 describe the computation of income and gross receipts taxes. To ensure the assumed rate of return payable to direct equity is achieved, we assume all electricity produced is sold at a price equal to post-tax ACOE. To calculate the post-tax ACOE, income and gross receipts taxes and resulting post-tax ACOE must be calculated iteratively. State and federal income taxes are computed using the ACOE as the sales price to compute annual profits, deducting depreciation, interest paid on traditional debt and any other tax-incentive payments.[29] Annual income taxes payable are then added to the pre-tax system costs to determine a new ACOE and the computation of income taxes is repeated until convergence is achieved. Gross receipts taxes are handled similarly, with taxes payable on gross sales computed iteratively until it converges to a constant payment.

[29] Federal depreciation is computed using the MACRS method, and state depreciation and incentives computed as specified in Table 2. For federal taxes, up to 80% of any annual losses recorded are carried forward and deducted against future income, consistent with Federal tax rules.

2.4 Capacity Factors

Table 5 describes the potential gross and net capacity factors used in the analysis. Gross capacity factors (GCF) shown in Column A were determined for the best 5 percent of land areas in each state from the "Cumulative Area vs. Gross Capacity Factor" charts developed by AWS Truepower and NREL, which are publicly available from the U.S. Department of Energy's WindExchange website.[30] Since GCF does not include adjustment for reductions in output due to operational considerations or turbine wake, two types of adjustment were made to estimate potential net capacity factors possible in each state. First, the GCF in each state was adjusted to account for constant fixed factors (those that do not change over time) that reduce facility output. This resulted in a 9.8 percent adjustment to the GCF of each state and these net capacity factors (NCF) are shown in Column B of Table 5.[31] Second, an accumulative degradation factor to account for reduced turbine performance over time such as blade efficiency reductions and increasing maintenance needs was applied using a degradation rate adjustment of 1 percent annually. Over the life of a facility this eventually reduces capacity factor by an additional 17.4 percent over 20 years, or 25.3 percent over 30 years, as shown in the last two columns of Table 5.

Table 5: Capacity Factors Determined for each WECC State

State	**Column A** Estimated Gross Capacity Factor Possible at top 5% of land (2014 Technology)	**Column B** Estimated Net Capacity Factor Possible at top 5% of land (2014 Technology)	**Column C** Net Capacity Factor after 20 years using 1% Degradation Rate	**Column D** Net Capacity Factor after 30 years using 1% Degradation Rate
WY	56%	50.5%	41.7%	37.7%
NM	56%	50.5%	41.7%	37.7%
MT	56%	50.5%	41.7%	37.7%
CO	55%	49.6%	41.0%	37.1%
CA	46%	41.5%	34.3%	31.0%
OR	45%	40.6%	33.5%	30.3%
WA	45%	40.6%	33.5%	30.3%
ID	45%	40.6%	33.5%	30.3%
UT	42%	37.9%	31.3%	28.3%
AZ	41%	37.0%	30.6%	27.6%
NV	38%	34.3%	28.3%	25.6%

As previously described, other factors also determine wind development beyond wind resource. California has the greatest generation capacity in the WECC yet ranks fifth in Table 5. This demonstrates two

[30] See the "Cumulative Area vs. Gross Capacity Factor" charts available for each state at the WindExchange website (Wind Energy Maps and Data section) https://windexchange.energy.gov/maps-data, accessed October 1, 2018).

[31] These include a 4% adjustment factor for wind farm wake effects (turbine wake interference with other wind turbines), a 1% reduction for high winds or extreme temperatures that require turbines to shut down, a 2% reduction for electrical efficiency losses, and 0.5% reduction for consumptive power losses necessary to maintain operation of the wind turbines. These are consistent with losses used in industry. See for example (Vaisala, 2016). The product of the availabilities implied by these factors is 0.901636, and this multiplier was used to reduce GCF to net values.

important facts to note with respect to wind development and wind resource. First, some states have very high potential capacity factors in local regions, even if on average wind potential is lower across the rest of the state. All else equal, such premium sites could be expected to be developed first, and since wind is still a relatively undeveloped resource in the west, the existence of such premium sites can explain some of why a state like California has the greatest wind capacity in the WECC despite its relatively lower rank in Table 1. Secondly, given the long history of wind incentives and the large market and demand for renewable energy in California, that state has a long history of development that contributes to its capacity. With respect to current development though, wind resources as described in Table 5 are quite correlated with current wind development (recent construction + projects under construction and in development) in the west. Using AWEA (2018) data, the states with the greatest current development in order are: Wyoming, New Mexico, Colorado, California and Montana, which is very nearly the order of wind resource quality presented in Table 1.

Again, as previously described, other factors may also affect development of wind generation in a particular state. States that are relatively farther from the largest markets or load centers may incur greater costs to develop necessary transmission and interconnection infrastructure to deliver power to market (Hitaj, 2013 and Godby, Taylor and Coupal, 2016). Several industry transmission planning reports and academic studies have discussed the need for greater transmission development if wind generation in the west is to be developed on much larger scales than seen today (see for example: GE Energy, 2010; and Godby, Torell and Coupal, 2014). These concerns seem validated by some currently proposed wind development projects such as the Power Company of Wyoming's Chokecherry and Sierra Madre project (3000 MW), and the Pathfinder Project (2100 MW). Both proposed projects are located in Wyoming and include costly transmission expansion as part of their proposals to deliver power to California markets.[32] The inclusion of such transmission capacity in wind projects is relatively rare, and can increase the total cost of such development significantly. Given that the wind resource is nearly equal across the top four states, however, this suggests that cost and incentives can be an important determinant of development between the four states with the best wind resources, as has been shown in previous academic studies.

3. Estimated State Cost Differences and Tax Policy Impacts

3.1 Estimated ACOE Results across States

For the computations of ACOE presented, projects were assumed to use current technology and project capacity assumed was 300 MW.[33] None of the cost modeling included transmission development, thus it was presumed that sites had transmission and interconnection infrastructure available to access the

[32] When transmission development is necessary to access markets, the scale of the wind project necessary to justify such development is often very large. For example, the Power Company of Wyoming is developing what would be the largest wind project in the country at 3000 MW, and includes a DC transmission line over 650 miles in length to deliver power to southern California. The 2100 MW Pathfinder project in central Wyoming proposed building a 525-mile transmission line. also to deliver power to southern California. Both projects are significantly larger than most wind developments usually undertaken. When such scale is necessary to make transmission investment cost effective, it can greatly complicate project development and increase the necessary funding required to complete the project, which may reduce the probability such projects are completed.

[33] If such a project was comprised of 130 wind turbines, each with a production capacity of just over 2.3 MW, this would be consistent with the average turbine size of 2.32 MW installed nationally in 2017-18 (DoE, 2018).

western grid. With respect to project details, all sites were assumed to begin construction in 2018, with operations beginning in 2019, allowing access to federal production tax credits (PTC's) worth $19/MWh for the first ten years of operation.[34] Fixed O&M costs were assumed to increase at an annual 1.5 percent rate of inflation. Facility overnight capital costs for all projects were assumed to be $1610/kW, consistent with data reported in DoE (2018). For comparison, two project lifetimes were considered: 20 years, consistent with projects built over the past two decades, and 30 years, the assumed life of new projects now beginning to be built. These and other cost assumptions used in the analysis are summarized in Table 4.

The two most significant determinants of ACOE differences across all eleven WECC states were (i) resource differences, which affect a state's capacity factor and therefore the expected hours and generation output that the costs are expressed in, and (ii) state differences in construction and labor costs that affect the cost of project construction and operation. Using the net state capacity factors presented in Table 5, wind resources are 47 percent greater in the best states (Wyoming, Montana and New Mexico) than the worst state in the west, Nevada; and wind resources in Colorado differ by less than two percent from the top three states. Regional costs differences are only somewhat smaller than resource differences across the west, with the highest cost state (California) having estimated construction costs almost 33 percent greater than the lowest cost state (New Mexico), and 30 percent greater than the next two lowest cost states (Wyoming and Colorado).

Given these large differences in resource quality and construction costs, ACOE for each state was computed under two scenarios. To isolate resource and regional cost differences from the resulting estimates, an ACOE cost calculation was performed across states assuming each had identical labor and construction costs (the regional cost adjustment factor was set to 1.0 across all states), and each state was assumed to have a 35 percent capacity factor in the first year of operation, with the output degrading at a 1 percent rate across all remaining years of a project's life. In these estimates, only state tax and incentive policies differ. The second scenario computed more realistic ACOE estimates across states, applying the regional cost differences shown in Table 3 to determine overnight capital costs and annual O&M costs. This scenario also computed ACOE setting the initial net capacity factors at the values shown for the top 5 percent of locations by state in Column B of Table 5. These were then degraded at a 1 percent annual rate over the life of the project. Two project lifetimes were assumed in each scenario, 20 and 30 years. Because 20-year lifetime estimates are more common in other studies and results are broadly consistent across either assumed project lifespan, 20-year results are presented in the main text, while 30-year results are presented in the Appendix. The resulting ACOE estimates are expressed as a cost range for each state and shown in Figure 7, and the decompositions of these results are presented in detail in Tables 6 and 7.

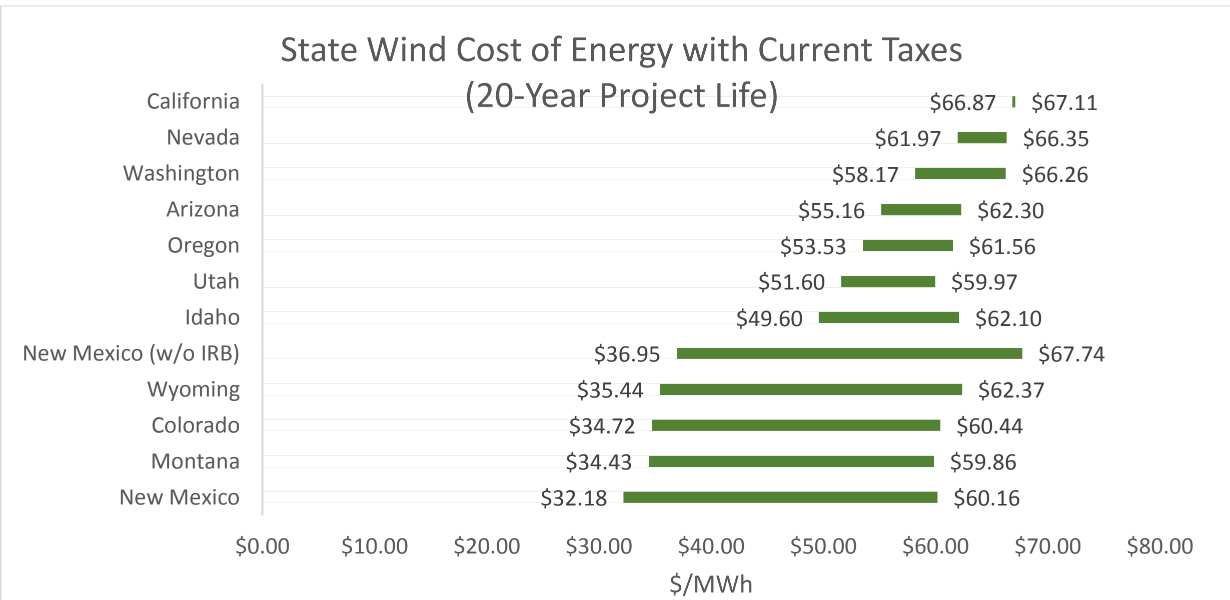
Figure 7 presents the estimated ACOE range by state. Values on the right-hand side of the range are the computed ACOE using constant capacity factor and identical regional cost assumptions. Those on the left of each bar represent the ACOE when state capacity factor and regional cost differences are taken into

[34] This assumes projects broke ground late in 2017 to receive $19/MWh. It was assumed the nominal value of this credit rose at a 1.1% rate of inflation per year based on recent inflation adjustment, to maintain a constant real subsidy value.

account.[35] Both high and low-cost estimates for each state account for specific state incentives and tax differences. New Mexico appears twice in the chart as projects may or may not take advantage of industrial revenue bonding and associated payments in lieu of taxes or tax payments at negotiated rates. When bonding and negotiated rates are not assumed, estimates used current New Mexico tax rates and practices.

Results from Figure 7 verify previous conclusions. First, the relative importance of resource quality is apparent. The low-end of the costs results in Figure 7 reflect not only differences in tax environment, but also resource quality and regional cost differences. Comparison of the results in Figure 7 and the resource quality in Table 5 show the importance of capacity factor. The four states with potential gross capacity factors exceeding 50 percent each have significantly lower costs than all other states where the capacity factors are much lower. The similarity of capacity factors across these four states also suggests that none of the top four states currently has a significant resource advantage given current and future technologies expected.

Figure 7: Estimated ACOE Ranges by WECC State



Among the lowest cost states in Figure 7, results also imply that differences in regional labor costs are very important. The four lowest cost states have regional cost index values varying from 0.96 to 0.92, as shown in Table 3. Given the similarity in resources and regional costs, it may be predictable the four states with lowest computed ACOE are New Mexico, Montana, Colorado and Wyoming.

Closer inspection also suggests the importance of state tax and incentive differences across these states in determining their overall ACOE values and cost competitiveness. This is most apparent with respect to the state of New Mexico. Based on the computations performed here, the availability of industrial revenue bonding, which is now commonly used for wind projects in the state, results in a 14.8 percent reduction

[35] The exception is Nevada. Because the net capacity factor at the top 5% of the land is 34.3 percent, when its state-specific capacity factor and regional costs are considered the ACOE is lower and this value is presented on the right-hand side of the range, while the 35 percent/no regional cost difference value is shown on the left-hand side.

of the ACOE cost.[36] The availability of such incentives gives New Mexico a clear advantage over other low-cost states, allowing the ACOE of the state to be seven percent lower than in Montana, 7.9 percent lower than in Colorado and 10.1 percent lower than Wyoming's ACOE. Each of these states' costs would otherwise be lower than New Mexico's if such bonding were not used.

Tables 6 and 7 describe the impact of incentives and tax reductions in more detail across states. These results all apply to a presumed project built in 2018 using the most current technology available, and in locations that can access capacity factors similar to those assumed.[37] Three states have no incentives available for wind (California, Washington and Wyoming). New Mexico also allows no breaks if bonding is not used. When capacity factor and regional cost differences are included in cost calculations (Table 6), the average reduction in taxes due to incentives is 48.1 percent, with a range of reductions from 19.3 percent (Oregon) to nearly 70 percent in Colorado. Reductions in the resulting cost per MWh of energy range from a low of $0.76 in Oregon, to $4.13 in Idaho, with an average cost reduction of $2.64. The benefit of a low tax environment on keeping taxes low, even without incentives can also be seen. While Wyoming offers no official incentives, the low-cost tax environment in the state results in its tax cost being similar to that of others offering incentives, with a tax cost of $3.05 per MWh of production. This is only slightly less than the $3.14 average cost across states though it includes the unique $1.00 per MWh production tax applied in that state. The result of this production tax is an increase in ACOE over a $20-year period of $0.89.[38] The results in Table 7 identify the value of incentives offered by state if resources and cost differences are not considered. When capacity factors and regional costs are held constant the average reduction in tax costs shown in Table 7 is 46.3 percent across states offering incentives, with a low of 18.8 percent in Oregon, to a high of 68.8 percent in Colorado. Cost reductions resulting from incentives in this scenario range from $0.84 in Oregon to $5.52 in Colorado.

Figure 8 summarizes the state tax burdens on a per MWh basis after incentives are applied across WECC states, both when capacity factor and regional costs are held constant, and when state-specific wind resources and regional costs are considered. As previously described, taxation policies differ markedly among states, and as Figure 8 shows, the resulting tax burdens are similarly different. As might be expected given the previous discussion, Colorado has the lowest tax burden after incentives of any state. Montana follows, primarily due to the lack of a sales tax and incentives. Utah, Idaho and Arizona then follow, again reflecting the high value of incentives in these states. Following these states are New Mexico and Wyoming, which are instructive for different reasons. Both have similar tax burdens when state capacity factors and regional costs are considered. New Mexico, however, has the lowest ACOE across states while Wyoming is fourth. Wyoming has no incentives, and New Mexico's primary incentive is its ability to use bonding. As shown in Figure 7, this policy is the primary reason the state has the lowest ACOE across WECC states, as without it, New Mexico's ACOE would rank fourth.

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[36] The computation of ACOE for New Mexico when industrial revenue bonds are used was based on the 2018 conditions a recent project by Pattern Energy was able to negotiate. See https://www.ruidosonews.com/story/news/local/community/2018/12/20/formula-approved-distribution-wind-farm-payments-lieu-taxes/2379218002/ for a description.

[37] Note that these reductions in cost do not reflect impacts on system financing costs of any sales tax incentives.

[38] The $1.00 per MWh production tax in Wyoming does not increase the calculated average cost of energy by $1.00 per MWh amount for two reasons. First, it is not applied in the first two years of operation. Secondly, because capacity factor is assumed to degrade at a 1 percent rate per year, the cost of the tax is reduced slightly since the years in which the tax is applied are assumed to have a lower output than the years when the tax is not applied.

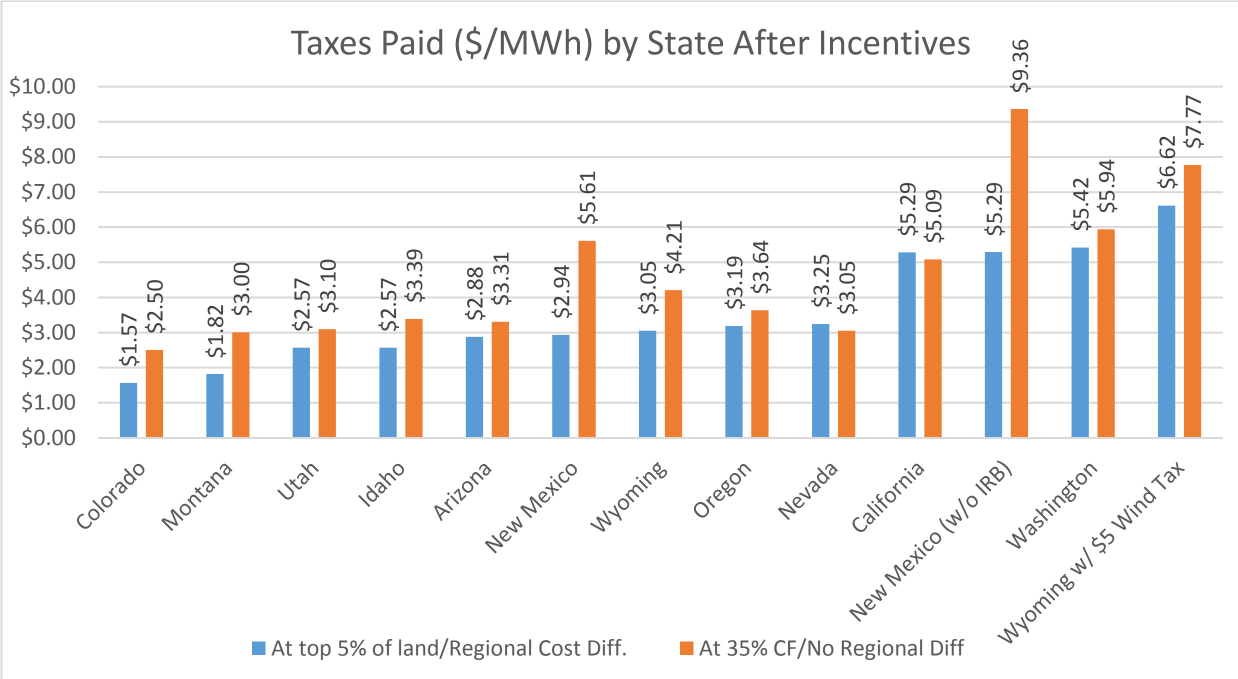
Table 6: State Cost Components at Top 5% Capacity Factor and including Regional Cost Differences

	Arizona	California	Colorado	Idaho	Montana	Nevada	New Mexico	New Mexico (w/o IRB)	Oregon	Utah	Washington	Wyoming	Wyoming w/ $5 Wind Tax
System & Federal Taxes $/MWh													
System Cost	$26.19	$29.66	$19.11	$24.36	$19.17	$30.61	$18.37	$18.37	$26.10	$25.56	$26.34	$18.77	$18.77
Federal Tax Credits	($6.87)	($6.87)	($6.87)	($6.87)	($6.87)	($6.87)	($6.87)	($6.87)	($6.87)	($6.87)	($6.87)	($6.87)	($6.87)
Financing Cost	$18.14	$21.82	$10.27	$15.86	$9.74	$21.84	$7.57	$9.88	$16.61	$16.08	$18.42	$10.02	$10.02
Operating Costs	$13.94	$15.58	$10.15	$12.92	$10.11	$16.13	$9.75	$9.80	$13.69	$13.48	$13.95	$9.98	$9.98
Federal Income Taxes	$0.88	$1.39	$0.48	$0.76	$0.45	$1.39	$0.42	$0.47	$0.82	$0.77	$0.90	$0.48	$0.47
Pre-State Tax Total	**$52.28**	**$61.58**	**$33.15**	**$47.03**	**$32.61**	**$63.11**	**$29.25**	**$31.66**	**$50.34**	**$49.03**	**$52.75**	**$32.39**	**$32.38**
State Taxes Before Incentive $/MWh													
Sales Taxes (financed)	$1.45	$1.69	$0.96	$0.99	$0.00	$1.64	$0.93	$0.93	$0.00	$1.16	$1.57	$0.68	$0.68
Property Taxes	$4.85	$3.06	$4.21	$4.13	$3.12	$5.33	$2.15	$2.22	$3.82	$3.24	$3.59	$1.48	$1.48
Income Tax	$0.22	$0.54	$0.00	$0.11	$0.00	$0.00	$0.00	$0.00	$0.14	$0.08	$0.00	$0.00	$0.00
Gross Receipt Taxes	$0.00	$0.00	$0.00	$1.47	$0.00	$0.08	$1.83	$2.14	$0.00	$0.00	$0.26	$0.00	$0.00
Excise Taxes	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.89	$4.45
State Taxes w/o Incentives	**$6.52**	**$5.29**	**$5.17**	**$6.70**	**$3.12**	**$7.05**	**$4.91**	**$5.29**	**$3.95**	**$4.48**	**$5.42**	**$3.05**	**$6.62**
State Taxes After Incentives $/MWh													
Sales Taxes	$1.45	$1.69	$0.59	$0.99	$0.00	$0.76	$0.30	$0.93	$0.00	$0.00	$1.57	$0.68	$0.68
Property Taxes	$1.21	$3.06	$0.98	$0.00	$1.82	$2.40	$0.81	$2.22	$3.05	$3.24	$3.59	$1.48	$1.48
Income Taxes	$0.22	$0.54	$0.00	$0.11	$0.00	$0.00	$0.00	$0.00	$0.14	($0.67)	$0.00	$0.00	$0.00
Gross Receipt Taxes	$0.00	$0.00	$0.00	$1.47	$0.00	$0.08	$1.83	$2.14	$0.00	$0.00	$0.26	$0.00	$0.00
Excise Taxes	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.89	$4.45
State Taxes w/ Incentives	**$2.88**	**$5.29**	**$1.57**	**$2.57**	**$1.82**	**$3.25**	**$2.94**	**$5.29**	**$3.19**	**$2.57**	**$5.42**	**$3.05**	**$6.62**
Reduction in State Taxes due to Incentives	**$3.64**	**$0.00**	**$3.60**	**$4.13**	**$1.30**	**$3.80**	**$1.97**	**$0.00**	**$0.76**	**$1.91**	**$0.00**	**$0.00**	**$0.00**
% Reduction in State Taxes due to Incentives	**55.8%**	**0.0%**	**69.7%**	**61.6%**	**41.6%**	**53.9%**	**40.2%**	**0.0%**	**19.3%**	**42.7%**	**0.0%**	**0.0%**	**0.0%**
Average Cost of Electricity (ACOE) $/MWh	**$55.16**	**$66.87**	**$34.72**	**$49.60**	**$34.43**	**$66.35**	**$32.18**	**$36.95**	**$53.53**	**$51.60**	**$58.17**	**$35.44**	**$38.99**
Assumed Capacity Factor	37.0%	41.5%	49.6%	40.6%	50.5%	34.3%	50.5%	50.5%	40.6%	37.9%	40.6%	50.5%	50.5%
Assumed Regional Cost Difference	0.96	1.22	0.94	0.98	0.96	1.04	0.92	0.92	1.05	0.96	1.06	0.94	0.94

Table 7: State Cost Components at 35% Capacity Factor and no Regional Cost Differences

	Arizona	California	Colorado	Idaho	Montana	Nevada	New Mexico	New Mexico (w/o IRB)	Oregon	Utah	Washington	Wyoming	Wyoming w/ $5 Wind Tax
System & Federal Taxes $/MWh													
System Cost	$28.81	$28.81	$28.81	$28.81	$28.81	$28.81	$28.81	$28.81	$28.81	$28.81	$28.81	$28.81	$28.81
Federal Tax Credits	($6.87)	($6.87)	($6.87)	($6.87)	($6.87)	($6.87)	($6.87)	($6.87)	($6.87)	($6.87)	($6.87)	($6.87)	($6.87)
Financing Cost	$20.89	$20.90	$20.19	$20.46	$19.30	$20.01	$17.14	$20.76	$19.29	$19.30	$21.00	$20.34	$20.34
Operating Costs	$14.84	$17.85	$14.54	$15.03	$14.69	$15.69	$14.27	$14.36	$15.74	$14.69	$16.01	$14.56	$14.56
Federal Income Taxes	$1.32	$1.32	$1.26	$1.27	$0.91	$1.27	$1.20	$1.32	$0.95	$0.93	$1.36	$1.31	$1.30
Pre-State Tax Total	**$58.99**	**$62.02**	**$57.94**	**$58.71**	**$56.85**	**$58.91**	**$54.55**	**$58.38**	**$57.92**	**$56.87**	**$60.32**	**$58.16**	**$58.14**
State Taxes Before Incentive $/MWh													
Sales Taxes (financed)	$1.59	$1.64	$1.45	$1.17	$0.00	$1.54	$1.46	$1.46	$0.00	$1.30	$1.72	$1.04	$1.04
Property Taxes	$5.33	$2.97	$6.34	$4.88	$4.68	$5.02	$3.37	$3.48	$4.21	$3.65	$3.93	$2.28	$2.28
Income Tax	$0.38	$0.48	$0.23	$0.38	$0.27	$0.00	$0.36	$0.41	$0.26	$0.20	$0.00	$0.00	$0.00
Gross Receipt Taxes	$0.00	$0.00	$0.00	$1.85	$0.00	$0.08	$3.53	$4.01	$0.00	$0.00	$0.29	$0.00	$0.00
Excise Taxes	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.89	$4.45
State Taxes w/o Incentives	**$7.31**	**$5.09**	**$8.02**	**$8.27**	**$4.95**	**$6.63**	**$8.71**	**$9.36**	**$4.48**	**$5.16**	**$5.94**	**$4.21**	**$7.77**
State Taxes After Incentives $/MWh													
Sales Taxes	$1.59	$1.64	$0.89	$1.17	$0.00	$0.72	$0.47	$1.46	$0.00	$0.00	$1.72	$1.04	$1.04
Property Taxes	$1.33	$2.97	$1.39	$0.00	$2.73	$2.26	$1.26	$3.48	$3.37	$3.65	$3.93	$2.28	$2.28
Income Taxes	$0.38	$0.48	$0.23	$0.38	$0.27	$0.00	$0.36	$0.41	$0.26	($0.56)	$0.00	$0.00	$0.00
Gross Receipt Taxes	$0.00	$0.00	$0.00	$1.85	$0.00	$0.08	$3.53	$4.01	$0.00	$0.00	$0.29	$0.00	$0.00
Excise Taxes	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.89	$4.45
State Taxes w/ Incentives	**$3.31**	**$5.09**	**$2.50**	**$3.39**	**$3.00**	**$3.05**	**$5.61**	**$9.36**	**$3.64**	**$3.10**	**$5.94**	**$4.21**	**$7.77**
Reduction in State Taxes due to Incentives	**$4.00**	**$0.00**	**$5.52**	**$4.88**	**$1.95**	**$3.58**	**$3.10**	**$0.00**	**$0.84**	**$2.06**	**$0.00**	**$0.00**	**$0.00**
% Reduction in State Taxes due to Incentives	**54.7%**	**0.0%**	**68.8%**	**59.0%**	**39.4%**	**54.0%**	**35.6%**	**0.0%**	**18.8%**	**40.0%**	**0.0%**	**0.0%**	**0.0%**
Average Cost of Electricity (ACOE) $/MWh	**$62.30**	**$67.11**	**$60.44**	**$62.10**	**$59.86**	**$61.97**	**$60.16**	**$67.74**	**$61.56**	**$59.97**	**$66.26**	**$62.37**	**$65.91**
Assumed Capacity Factor	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Assumed Regional Cost Difference	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Figure 8: Comparative Tax Burdens on Wind development by State



3.2 State Taxation Policy and Development Tradeoffs

The benefit of New Mexico's unique bonding incentive environment occurs for two reasons and is instructive for states considering changes to their tax structure. First, the creation of industrial revenue bonds reduces the interest rate a project can access in financing its project, which reduces overall project. Calculations presented here identify the value of this benefit to be $2.31 per MWh. The second benefit of this tax structure is the potential reduction in negotiated tax costs, which can reduce tax burden and therefore the ACOE of a project. Using reductions in taxes negotiated by recent projects, this results in an additional $2.35+ per MWh in tax reductions, however, even if no reduction in taxes took place, just the financing cost savings estimated for using this bonding program would leave New Mexico with the lowest ACOE among WECC states.

This suggests that one means of avoiding a fiscal tradeoff between tax reductions cost competitiveness is to consider alternative funding mechanisms that allow such cost reductions. Using a county bonding mechanism could allow a state to both lower wind developer's costs and avoid foregoing tax revenue to incentivize wind development. In some circumstances, potentially using bonding to reduce project costs could be used in conjunction with revenue increasing measures, and still result in reduced ACOE, competitively improving a state's wind development costs while increasing tax revenues derived from wind.

From the various forms of taxation that are clearly present across states in the WECC, a logical question arises as to which forms of taxation lead to the least tradeoff with respect to economic development while also increasing revenue. What forms of state taxation seem to make little difference? There is a long literature on how specific taxes affect economic development and whether some taxes are more important than others. The literature on such questions is inconsistent with respect to development generally (see for review and an example Gale et al., 2015). Hitaj (2013) is the only paper that specifically addresses at this question with respect to wind development. We use the Hitaj results to consider which types of taxes may be most important to consider when considering state wind development policies.

From Tables 6 and 7, one tax difference among states that makes little difference to overall costs is the presence or absence of a state income tax for wind developments. In Table 6, income taxes across states that assess them only increase the ACOE by $0.22 per MWh on average. Even when capacity factors and regional costs are equalized, this only rises to $0.33 per MWh.[39] While lower income taxes or a lack of income taxes is often considered a potential economic development advantage for some states, this is not true across industries. In capital intensive ones like wind generation, the income tax burden of such facilities is comparatively small relative to other taxes due to the high interest costs and depreciation that can be deducted. Therefore, states like Nevada, Washington and Wyoming in the WECC see little advantage in attracting wind development for having no income taxes. Overall, given the results shown in the tables, and the reality that large, capital intensive projects like wind developments can often have little income tax liability, using income taxation as a means of deriving state revenue appears to offer little deterrent to wind development, at least with respect to its impact on project costs. The converse argument also applies regarding income taxes and wind development – such projects may create much less income in states more reliant on income than other taxes.[40]

While Nevada and Washington have no income tax, they do assess a gross receipts tax, as do New Mexico and Idaho. This alternative form of tax can potentially capture greater revenues from wind generation than an income tax because such policies usually lack the sorts of deductions against taxes payable that income taxes allow. Such a tax can allow increased revenues for wind development over an income tax, but, as is apparent in Tables 6 and 7, it also does increase the cost of wind generation.

As noted previously, sales taxes affect wind project incentives in two ways. The direct effect comes through the fact that higher sales taxes increase tax costs and therefore increase the overall costs of a project in a state. They also affect a project indirectly, by increasing the after-tax system costs of a project, and therefore financing costs. Given these impacts the benefit of sales tax reductions on wind development may be larger than for exemptions on other taxes. Results in Hitaj (2013) suggest this is true. Given this result, the relative tradeoff between fiscal revenues and economic development may be lower for sales taxes relative to property taxes, the most common form of taxation on wind across WECC states.

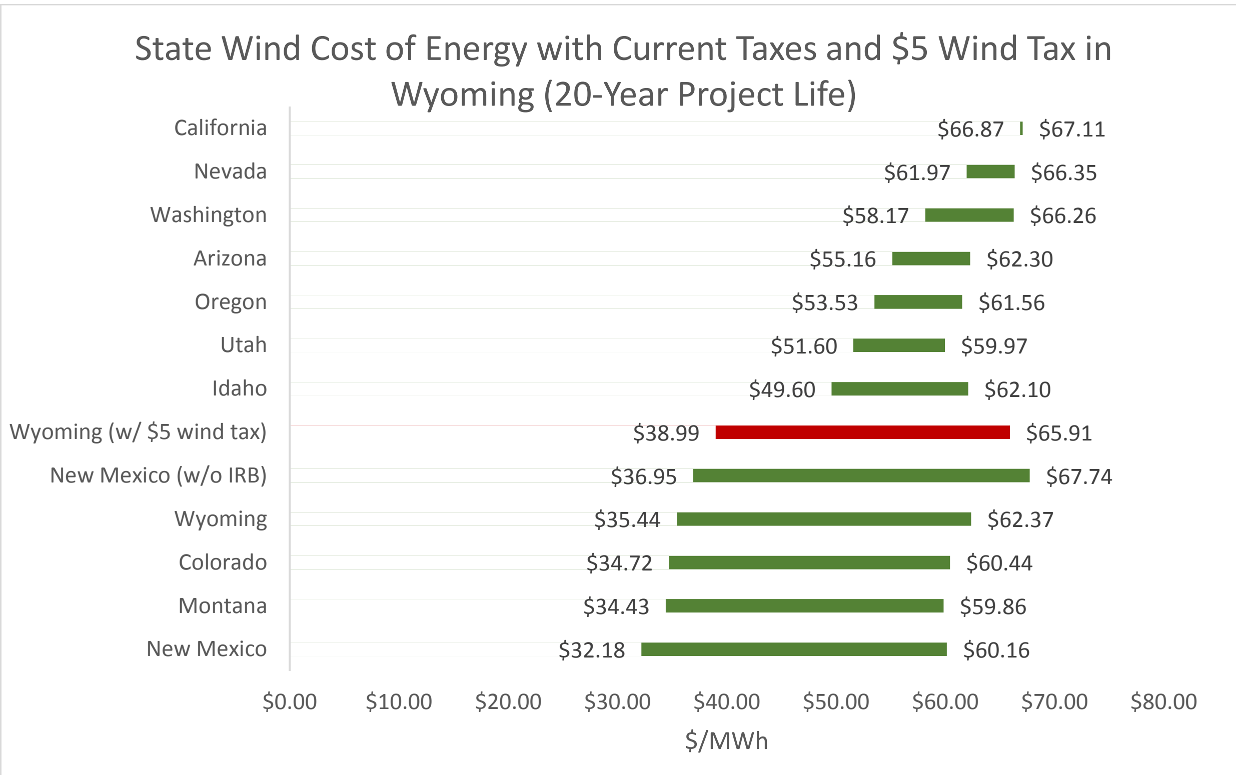
Tables 6 and 7 also show how all WECC states but Idaho charge wind development a property tax. Idaho is the only state that completely exempts wind from such taxes, while all other WECC states except California, Utah, Washington and Wyoming offer a reduction in the property taxes assessed for wind development. After all such exemptions, property taxes add an average of $1.97 to total ACOE across states when state-specific capacity factors and regional cost differences are accounted for. Hitaj (2018)

[39] The income tax costs rise when capacity factors are reduced as in the computation of ACOE, it is presumed the price electricity is sold for also rises. This results in greater revenues and therefore assessed income taxes than when capacity factors are higher as the lower costs that electricity can be sold for in this case result in lower taxable profits while still guaranteeing the rate of return to investors assumed.

[40] This conclusion is consistent with some of the findings in Hitaj (2013), however, she considers only corporate tax credits. She does not consider income taxes specifically, but all corporate taxes. General studies of corporate income and business tax impacts also show little negative impact (see Gale et al., 2015).

finds that of all taxes she considers, property tax exemptions create no statistically significant impact on wind development.[41] This suggests that development policies that rely in property tax exemptions as a means of attracting wind development may have larger tradeoffs than policies that offer exemptions from other taxes.[42] Results in the literature suggest then that using property taxes as a means of encouraging development are not cost-effective. Alternatively, if revenue increases are necessary within a state, it may be more advantageous to apply them to property taxes over other forms of taxation to minimize the effect on wind development, though more research on this is needed.[43]

Figure 9: Estimated ACOE Ranges by WECC State Assuming a $5/MWh Production Tax in Wyoming



The other form of taxation common on wind is a production incentive (or disincentive if taxes are charged on wind generation). In the WECC area, only Wyoming has such a tax structure. Hitaj (2013) finds this is the most powerful tax incentive (or in Wyoming's case, the production tax would act as a disincentive) a state can offer, with her results finding a $10 per MWh incentive could increase wind capacity by 20

[41] For some econometric specifications, this paper even identifies negative effects on development for property tax reductions.

[42] This finding is at odds with the general literature on property taxes and economic development, however, wind is far more capital intensive than general economic development is, and it is unclear such findings should be generalized to wind.

[43] While Hitaj's (2013) findings were robust, the paper uses data over a decade old. Similarly, other tradeoffs would have to be considered before developing such a policy. One problem that may be relevant is the timing of revenues and their impact on communities. Sales taxes generate revenue primarily over the period of wind facility construction, while property taxes provide local communities with a predictable stream of income for over a decade or more depending on depreciation schedules allowed. For this reason, the use of property tax increases may also be appealing to policy-makers as a means of raising revenues.

percent annually.[44] If such results hold true for Wyoming, the $1 per MWh would be responsible for reducing capacity additions by 2 percent annually. Recently, the State of Wyoming has considered increasing its production tax on wind from $1.00 per MWh to as high as $5.00 per MWh (see Godby et al. 2018). Hitaj's results would suggest this would result in a significant decrease in potential wind development in the state. With respect to its impact on the relative cost-competitiveness of Wyoming to attract wind development, the result of imposing such a tax can be seen in Tables 6, and 7, as well as Figures 7 and 8. Figure 9 reproduces Figure 7, but shows how Wyoming's comparative costs change relative to other states after such an increase is implemented. As can be seen in the figure, Wyoming's ACOE would rise by 10 percent assuming state-specific capacity factors and regional costs, though it would remain fourth lowest in the WECC. The cost increase would also cause the cost of wind development in Wyoming to now exceed the cost in New Mexico even if industrial revenue bonding in that state is not pursued. When state specific potential capacity factors and cost differences are considered, the ACOE in Wyoming with the increased tax is now over 21 percent higher than New Mexico's (when industrial revenue bonds are used), and over 13 percent higher than Montana's and 12 percent higher than Colorado's. All else equal, such a cost increase could be expected to have a significant impact on wind development in Wyoming relative to other low-cost states, which would be consistent with earlier estimates like Hitaj's.

Tables 6 and 7 more clearly demonstrate the impact of such a tax increase. The cost of the wind excise tax now increases from $0.89 per MWh previously, to $4.45, and more than doubles the total tax burden per MWh of wind generated electricity when state specific capacity factors and cost differences are considered. An additional disadvantage of such a tax increase in terms of state competitiveness is the fixed nature of the tax burden. Over time, wind costs have been declining on a per MWh basis due to reductions in capital costs that reduced financing burdens, and due to increases in wind productivity as demonstrated by rising capacity factors. This trend is expected to continue. When taxes are assessed on a percentage basis, as is the case with income, gross receipts, property and sales taxes, in a declining-cost environment taxes payable typically decline as well. This is apparent by comparison of the data presented in Tables 6 and 7. A fixed cost tax like that applied in Wyoming, however, has the opposite effect on tax burden, increasing as costs decline. Over time, such a tax structure will make a state more uncompetitive over time if costs are declining, and this problem would only be exacerbated if the state increases its revenue reliance on such taxation policy. This suggests that states looking to possibly increase tax revenues from wind development should consider production taxes very carefully. Previous literature suggests that they are a greater deterrent than any other tax increase to wind development, and results here suggest they can cause a state's cost competitiveness to worsen over time. Other approaches to increasing revenue and combining that with other approaches such bonding as used in New Mexico, could both maintain a state's cost competitiveness to attract wind development, while also allowing the opportunity to increase tax revenues earned per MWh. This would be in addition to attracting new development, which would also increase gross tax revenues (see Godby et al., 2016).

Comparison of tax policies across states can be instructive to identify potential implications of the results presented here and those of past research like that presented in Hitaj (2013). Figure 10 compares the finance and tax costs using data from Table 6 across the three states with the greatest degree of current development occurring to consider how policies in each state may be consistent with maximizing

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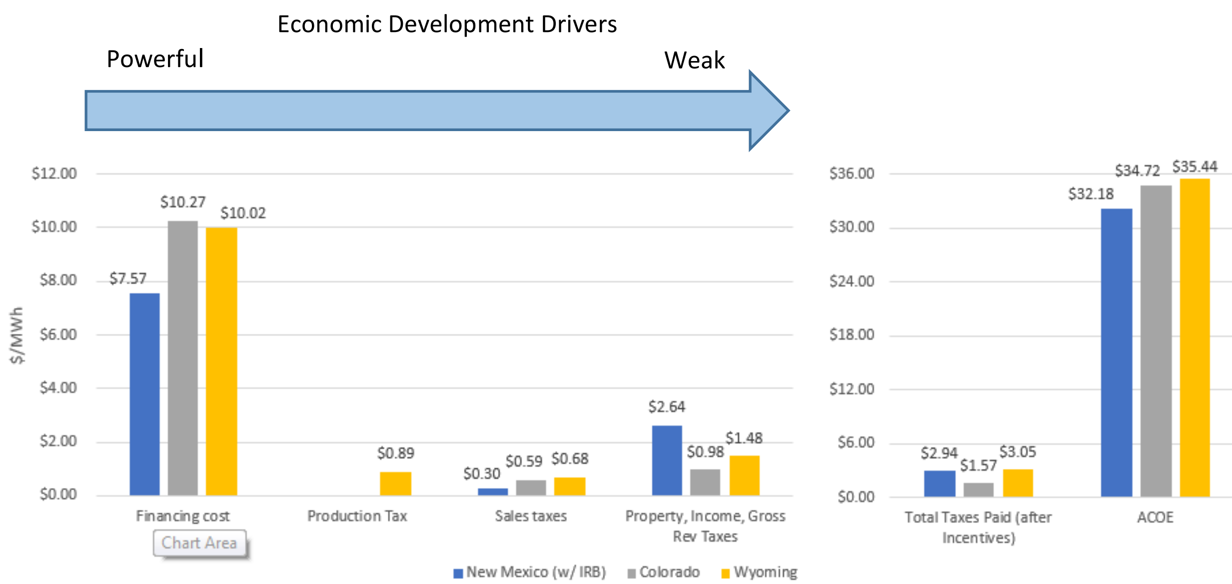
[44] Her data did not include Wyoming, as the tax came into effect after the terminal date of the dataset used in her paper.

economic development. The cost components of ACOE are arranged based on the relative degree to which they affect economic development based on Hitaj's (2013) results. Consideration of her results suggest that tax incentives after project completion are weaker drivers of investment than those that affect initial project financing conditions such as sales taxes, and this insight may be useful in building wealth in rural western communities where wind development could occur.

In Figure 10, the relative tax burden per MWh by state for sales, production and other taxes is shown, as are total tax revenues per MWh of production and overall ACOE by state, assuming state-specific capacity factors and regional costs. From the results presented, the potential impacts of state policies on state ACOE and economic development can be compared. In New Mexico, when industrial revenue bonds are used, New Mexico's total tax revenues per MWh are only 3 percent lower than Wyoming's yet its overall ACOE is 10 percent lower. The primary reason for the cost advantage New Mexico experiences over Wyoming is the impact of their bonding policy on the finance cost portion of ACOE, which three-quarters of Wyoming's financing cost.[45] Additionally, comparison of the two states' tax burdens per MWh indicate that gross receipts and property taxes create most of New Mexico's wind tax revenues, which could be expected to have a lower impact on wind development than sales or production taxes according to previous work. The cumulative effect of New Mexico's tax policies is to reduce the tradeoff between increasing its cost competitiveness to attract wind development and foregone tax revenues.

Figure 10: Cost and Tax Components by State



Alternatively, Wyoming's tax policies are less consistent with understood mechanisms that avoid deterring wind development while also improving state revenues. Over half of Wyoming's tax revenues per MWh rely on production and sales taxes, which have larger negative impacts on economic development per dollar earned from taxes. This suggests that Wyoming could improve its wind development competitiveness while protecting tax revenues by changing the composition of how it

[45] Some of the relative advantage ACOE New Mexico gains over Wyoming is due to the fact that regional costs in New Mexico are 2 percent lower than Wyoming's (capacity factors used here are the same across both states).

charges taxes on the wind industry and such policy may be something policy-makers wish to consider in the future.[46] Similarly, Colorado tax policy may be able to improve that state's wind development-fiscal revenue tradeoff through reconsideration of the composition of taxes on wind energy though the primary source of revenues in that state come from sources thought to have less impact on wind development. Further research is necessary to corroborate these conclusions, but results presented here and review of previous economic literature suggests there could be benefits to states that choose to "tax smarter" when considering how to avoid deterring wind development while also maintaining tax revenues.

3.3 Considering Tax Changes that Both Reduce Wind Development Costs While Increasing Tax Revenue

A simple example demonstrates the point made above. In 2009, Wyoming repealed its sales tax exemption on wind. Currently, the cost of sales tax on new wind development is $0.68 per megawatt hour as shown in Figure 10 and Table 6. Wyoming also charges a wind production tax costing $0.89 per megawatt hour. With existing property taxes, the total cost of taxes for new wind development in Wyoming is $3.05 per megawatt hour. Furthermore, given previous studies, the production and sales taxes Wyoming charges could be expected to create a greater disincentive to develop in Wyoming than using property, gross receipts or income taxes. Given these ideas, a simple policy experiment is performed to demonstrate how the Wyoming could both increase taxes collected per megawatt hour and reduce developer's costs to make the state more attractive to develop in, simply changing how taxes are collected on wind in the state.

We assume the sales tax exemption is reinstated on wind equipment in Wyoming, and the current $1 per megawatt hour production tax is rescinded. In place of these taxes we institute a gross receipts tax on the value of electricity produced, an idea Wyoming considered in 2009.[47] We assume a tax rate of 6 percent, applied to the value of each unit of electricity sold, which we assume occurs at the estimated ACOE value. We also assume the same net capacity factor and regional costs as used to create the Wyoming ACOE estimate under current tax policy shown in Table 6. The estimated ACOE of wind development in Wyoming is then and compared to the results under current Wyoming wind tax policy.

Table 8 presents the results of this comparative analysis. As can be seen from the table, assumed lifetime production, federal tax credits earned, and system cost remain unchanged for the tax change. The effect of the change is to eliminate sales taxes collected during construction, and production taxes paid over the life of the project, replacing these with a royalty fee of 6 percent, assessed on the revenues created from electricity sales, which is shown as a gross receipt tax. Undertaking the suggested policy reduces the ACOE of wind development in Wyoming from $35.44 to $34.93 per megawatt hour, a 1.5 percent reduction. With respect to other states' costs, Wyoming would still place fourth among the least expensive states to develop wind power in the west, however, the new costs are now less than a percent higher than

[46] Note the production tax in Wyoming applies to wind only, while changing property tax rates or imposing a gross receipts tax could potentially impact many more industries than just wind. Furthermore, the example presented is very simple and does not consider other complications such as how distribution formulas work within the state for different types of taxes, and the impacts such changes could have on the funding of particular expenditures that traditionally rely on specific revenue streams.

[47] In 2009, Wyoming considered a royalty fee on wind assessed on the value of electricity generated by wind in the state. This proposal suggested a royalty fee of 3 percent, which at the price of wind electricity at the time would have resulted in a cost of $2.50 to $3.00 per megawatt hour, depending on the value of wind generated electricity at the time of proposed enactment. See House Bill 275 "Wind Turbines Royalty Fee", and Madden (2019) for a description.

Colorado's the difference between Wyoming and Montana falls from 3 percent to 1.5 percent. The difference between Wyoming and New Mexico falls from 10.1 percent to 8.5 percent. The taxes collected per megawatt hour in Wyoming, however, increase from $3.05 to $3.31, an 8.3 percent increase. This is achieved because the reduced sales tax burden lowers the financing costs a project would have to undertake by 6.7 percent as sales taxes no longer have to be paid during construction while the project is not producing electricity. Federal income tax and operating costs are also reduced by 6.4 percent and 0.6 percent respectively. In effect, this change in tax composition has allowed a tax increase to occur without sacrificing economic competitiveness, as it results in a reduction in development cost, and an increase in taxes collected, avoiding any development-tax increase tradeoff.

Table 8: Results from eliminating Sales and Production Taxes in Wyoming and replacing them with a Gross Receipts Tax on Wind Generation.

	Results Assuming 6% Gross Receipts Tax, Sales Tax Exemption, No Pruduction Tax, Current Property Taxes		**Results under Current Wyoming Tax Policy**	
	Total Cost	**Total Cost per MWh**	**Total Cost**	**Total Cost per MWh**
	24,184,449	$34.93	24,184,449	$35.44
System & Federal Taxes				
System Cost	$454,020,000	$18.77	$454,020,000	$18.77
Federal Tax Credits	($166,050,794)	($6.87)	($166,050,794)	($6.87)
Financing Cost	$226,050,473	$9.35	$242,395,825	$10.02
Operating Costs	$239,830,065	$9.92	$241,311,439	$9.98
Federal Income Taxes	$10,878,103	$0.45	$11,623,537	$0.48
Pre-State Tax Total	$764,727,847	$31.62	$783,300,007	$32.39
State Taxes Before Incentive				
Sales Taxes (financed)	$16,426,444	$0.68	$16,426,444	$0.68
Property Taxes	$34,616,755	$1.43	$35,869,189	$1.48
Income Tax	$0	$0.00	$0	$0.00
Gross Receipt Taxes	$45,357,384	$1.88	$0	$0.00
Excise Taxes	$0	$0.00	$21,543,748	$0.89
State Taxes w/o Incentives	$96,400,582	$3.99	$73,839,380	$3.05
State Taxes After Incentives				
Sales Taxes	$0	$0.00	$16,426,444	$0.68
Property Taxes	$34,616,755	$1.43	$35,869,189	$1.48
Income Taxes	$0	$0.00	$0	$0.00
Gross Receipt Taxes	$45,357,384	$1.88	$0	$0.00
Excise Taxes	$0	$0.00	$21,543,748	$0.89
State Taxes w/ Incentives	$79,974,139	$3.31	$73,839,380	$3.05
Total Cost of Electricity /ACOE	$844,701,986	$34.93	$857,139,387	$35.44
Megawatt Hours Produced (20 years)	24,184,449		24,184,449	
Initial Net Capacity Factor	50.5%		50.5%	
Assumed Regional Cost Difference	0.94		0.94	

These are not the only potential advantages such a tax change would create. As noted, sales and production taxes have been shown in previous studies to have much greater effect on economic development than business tax changes. In Wyoming, it is likely the case that developers would prefer a gross receipts tax to the current production tax because if electricity revenues decline over time, the tax burden will similarly fall because it is charged on a percentage basis. This reduces potential risk given the recent trends of declines in generation costs. The reduction in sales tax also reduces the amount a developer must finance and raise funding for.

An additional advantage of a tax change like that shown is the stream of payments a gross receipts tax creates. The annual payments that could be expected would create a reliable income stream for the state and communities affected, lasting the life of the project. Conversely, a sales tax is typically a one-time revenue, and while when paid it is much larger and occurs much sooner than the annual gross receipts revenues that might be received in a given year, a sales tax does not create a sustainable revenue stream. In a community, one could argue the sales tax provides funds to pave roads but not on-going funds to maintain them, while a gross receipts tax can allow community funding of on-going expenses. Total taxes paid over the life of the project are also greater under the proposed gross receipts tax scheme.

4. Conclusions

Wind development has been identified as a potential source of development and economic diversification in the rural western United States. Given the fact that state policy can affect the cost of wind development, states should be cognizant of how tax policy changes can impact on realized wind development. Realized wind development, while not determined by cost alone, can be affected by the total cost of wind development in a state, and changes in tax policy should be undertaken with this in mind. This paper has attempted to create a comparison of wind development costs across western states, and how state taxation policy differences appear to affect these costs. These results can both inform policy-makers of the relative development costs across states currently, and may be useful to identify where changes in taxes can be made to better achieve state goals, while minimizing any negative impacts on wind development they may wish to encourage.

Research on how tax and other incentive policies impact wind generation development is well into its second decade and spans several methodologies. Previous work has relied on case studies, econometric methods or direct calculation of incentive benefits to wind facilities for different state tax and incentive strategies. As far as we are aware, however, only one study has attempted a “bottom-up” calculation and comparison of wind development costs that include taxation impacts across the WECC region states in the western United States. That study is now almost a decade old, and work presented here is intended to update previous findings.

The analysis presented attempts to estimate the impact of local state taxation and incentive policies on the cost to develop wind across the states in the Western Electricity Coordinating Council (WECC) region of the United States. The study was conducted by developing a detailed model describing the financial structure of a typical large utility-scale wind development. We argue that consideration of the capital structure of a wind development is crucial to understand how different taxation and other policies affect wind development incentives. Such an understanding is also necessary to develop taxation strategies that minimize competitive development and fiscal revenue tradeoffs.

Modeling estimates presented here indicate that four states have a significant advantage over the other seven states in the WECC region with respect to the potential cost of wind energy development within their borders. In order, the study identifies New Mexico, Montana, Colorado and Wyoming as having the lowest cost wind resources in the west given current wind resource estimates, regional cost differences and tax policies.

While currently the difference in costs from the highest cost of these states (Wyoming) and the lowest (New Mexico), is approximately 10 percent, and less than 3 percent between Wyoming, Montana and Colorado, potential future wind taxation changes in Wyoming could significantly disadvantage that state with respect to its overall cost competitiveness. Suggested increases in Wyoming's wind production tax could increase the state's wind development costs by an additional 10 percent, more than doubling the cost difference to the lowest cost state in the west. All else equal, this could make a meaningful difference in developer's willingness to consider Wyoming for wind development. This also could have important implications for the use of wind generation as an economic development strategy in the state. Furthermore, the type of tax chosen to raise revenues, a production tax, is computed as a fixed value, and in a declining cost environment would cause the tax burden it imposes on the overall cost of wind development to increase over time, worsening the state's costs relative to other states. This impact could be reduced if tax increases were considered using other types of taxes. Considering alternative forms of additional revenue generation on wind may also lessen the impact such tax choices have on wind development.

Results of this modeling exercise are valuable for several reasons. First, they estimate the relative rankings of states based on their potential wind development costs. These results are important as researchers and policy-makers attempt to understand why wind development patterns occur as they do across states. Secondly, the work identifies how state taxation policies affect these rankings. Understanding how potential policy changes could affect the cost of wind development relative to other states is important to consider to avoid unintended development impacts. This is especially important when the tax elasticity of particular policy changes is unknown. The third benefit of such an exercise is the ability to consider holistically how different taxation and incentive choices may impact the potential tradeoff between wind development and fiscal revenues. Some tax changes affect wind development not only by their direct effect on project tax burdens, but also through their impact on other costs, such as the cost of financing in the case of a sales tax. Given this, it is important to understand the capital, operating and tax structure of wind developments to appreciate how, for a given tax revenue or incentive change, different cost consequences may occur that affect the attractiveness of a state to wind development. Understanding such impacts can allow policy-makers to better understand the potential economic development and fiscal tradeoffs of a given set of policy or incentive choices they may consider. It can also allow lawmakers to maximize the effectiveness of taxation policies and to avoid undermining a state's competitiveness to attract new development.

Acknowledgements:

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Appendix

The following presents ACOE estimates, expressed in $/MWh across the eleven WECC states assuming the same parameterization and model as presented in the text. The only change is the assumption that projects have 30-year lifetimes, which is now becoming the norm with wind developments. Figure A1 compares ACOE estimates across two scenarios – the first assuming all states have the same 35 percent capacity factor and that there are no regional cost differences between states. These estimates correspond to the cost bounds on the right-hand side of the figure. The cost estimates on the left-hand side bounds are estimated assuming state-specific net capacity factors described in Table 5 of the text, and using regional cost factors to weight capital and O&M costs given in Table 3 of the text. Figure A2 shows the same sets of cost estimates as shown in Figure A1, except that Wyoming is now assumed to have a $5 per MWh production tax. Tables A1 and A2 decompose the ACOE estimates into their components to show how specific costs or taxes affect the overall ACOE.

Figure A1: Estimated ACOE Ranges by WECC State Assuming a 30-year Project Life

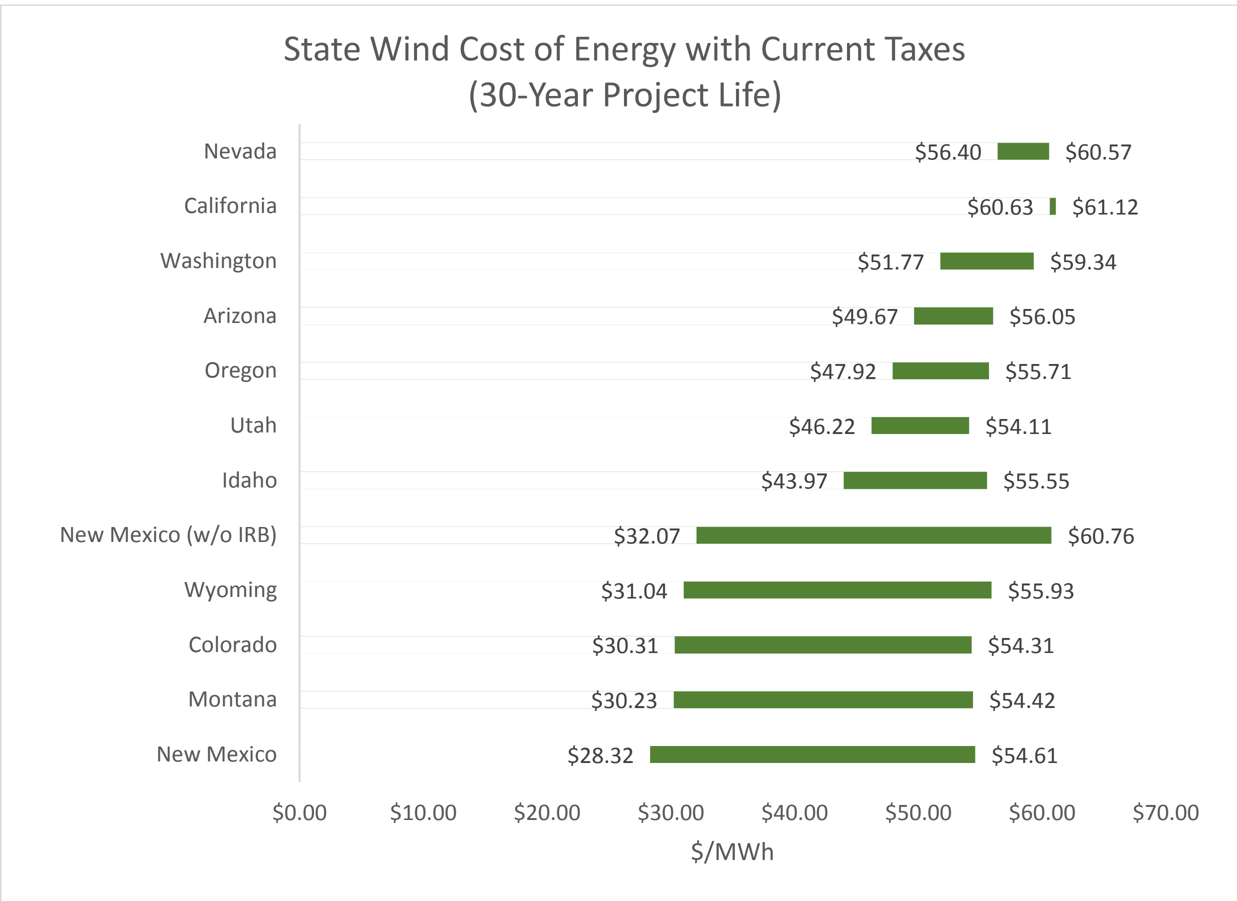

Figure A2: Estimated ACOE Ranges by WECC State Assuming a 30-year Project Life and a $5/MWh Production Tax in Wyoming

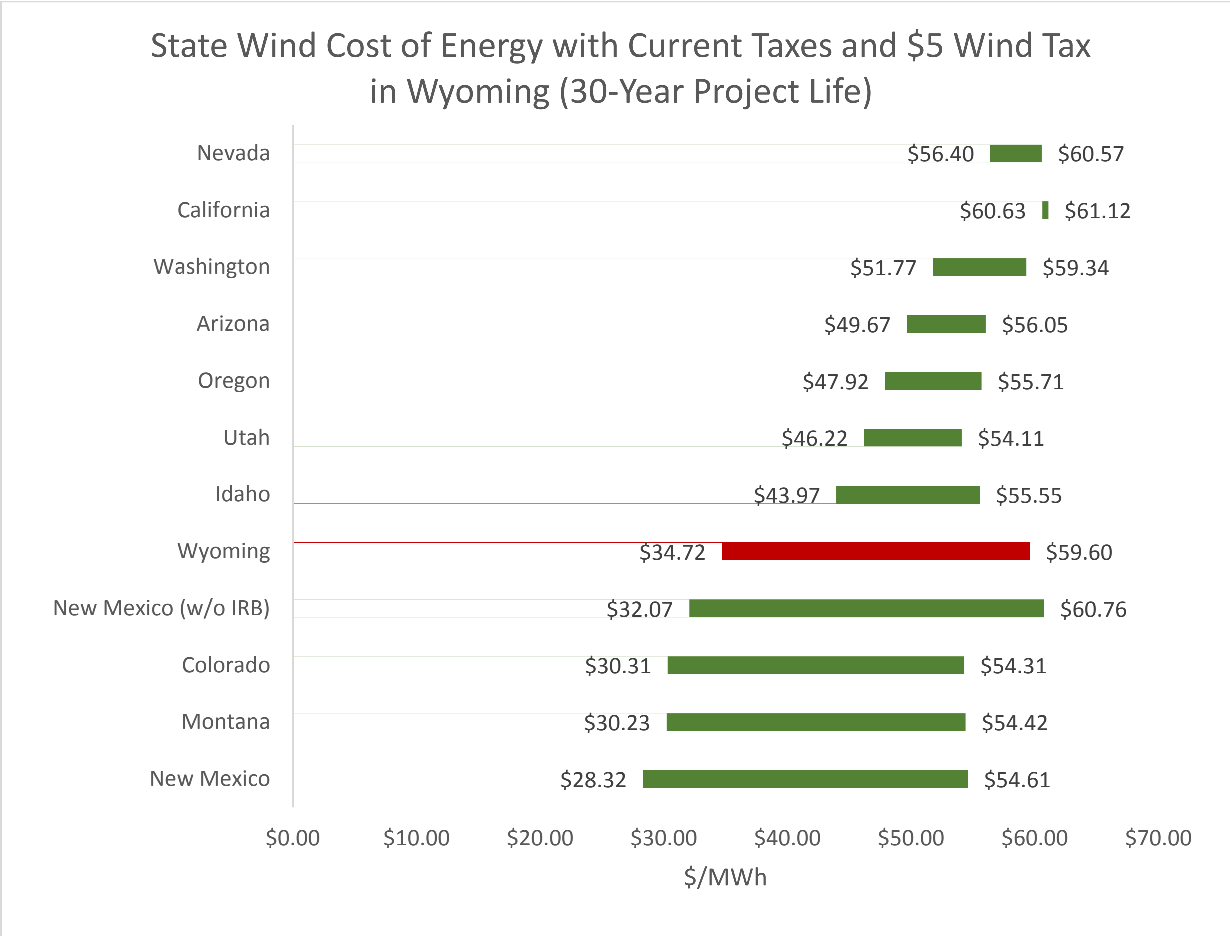

Table A1: State Cost Components assuming a 30-year Project Life at Top 5% Capacity Factor and including Regional Cost Differences

	Arizona	**California**	**Colorado**	**Idaho**	**Montana**	**Nevada**	**New Mexico**	**New Mexico (w/o IRB)**	**Oregon**	**Utah**	**Washington**	**Wyoming**	**Wyoming w/ $5 Wind Tax**
System & Federal Taxes $/MWh													
System Cost	$18.31	$20.74	$13.37	$17.03	$13.41	$21.40	$12.85	$12.85	$18.25	$17.87	$18.42	$13.13	$13.13
Federal Tax Credits	($4.80)	($4.80)	($4.80)	($4.80)	($4.80)	($4.80)	($4.80)	($4.80)	($4.80)	($4.80)	($4.80)	($4.80)	($4.80)
Financing Cost	$16.59	$20.23	$8.82	$14.34	$8.30	$20.25	$6.64	$8.43	$15.08	$14.56	$16.87	$8.57	$8.57
Operating Costs	$15.45	$17.34	$11.24	$14.32	$11.20	$17.90	$10.78	$10.85	$15.19	$14.93	$15.49	$11.05	$11.05
Federal Income Taxes	$1.67	$2.42	$0.45	$1.05	$0.42	$2.40	$0.39	$0.44	$1.27	$1.21	$1.62	$0.45	$0.44
Pre-State Tax Total	**$47.22**	**$55.93**	**$29.07**	$41.94	**$28.53**	$57.15	**$25.86**	**$27.77**	**$44.98**	**$43.77**	$47.60	**$28.40**	**$28.39**
State Taxes Before Incentive $/MWh													
Sales Taxes (financed)	$1.01	$1.18	$0.67	$0.69	$0.00	$1.14	$0.65	$0.65	$0.00	$0.81	$1.10	$0.47	$0.47
Property Taxes	$3.74	$2.56	$3.53	$3.46	$2.61	$4.88	$1.77	$1.82	$3.20	$2.72	$2.94	$1.24	$1.24
Income Tax	$0.51	$0.96	$0.00	$0.37	$0.00	$0.00	$0.00	$0.00	$0.38	$0.26	$0.00	$0.00	$0.00
Gross Receipt Taxes	$0.00	$0.00	$0.00	$1.32	$0.00	$0.08	$1.59	$1.83	$0.00	$0.00	$0.23	$0.00	$0.00
Excise Taxes	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.92	$4.62
State Taxes w/o Incentives	**$5.26**	**$4.70**	**$4.21**	$5.84	**$2.61**	$6.10	**$4.00**	**$4.30**	**$3.58**	**$3.79**	$4.26	**$2.64**	**$6.34**
State Taxes After Incentives $/MWh													
Sales Taxes	$1.01	$1.18	$0.41	$0.69	$0.00	$0.53	$0.21	$0.65	$0.00	$0.00	$1.10	$0.47	$0.47
Property Taxes	$0.94	$2.56	$0.82	$0.00	$1.71	$2.83	$0.66	$1.82	$2.56	$2.72	$2.94	$1.24	$1.24
Income Taxes	$0.51	$0.96	$0.00	$0.37	$0.00	$0.00	$0.00	$0.00	$0.38	($0.27)	$0.00	$0.00	$0.00
Gross Receipt Taxes	$0.00	$0.00	$0.00	$1.32	$0.00	$0.08	$1.59	$1.83	$0.00	$0.00	$0.23	$0.00	$0.00
Excise Taxes	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.92	$4.62
State Taxes w/ Incentives	**$2.46**	**$4.70**	**$1.24**	$2.38	**$1.71**	$3.44	**$2.46**	**$4.30**	**$2.94**	**$2.45**	$4.26	**$2.64**	**$6.34**
Reduction in State Taxes due to Incentives	$2.81	$0.00	$2.97	$3.46	$0.91	$2.66	$1.54	$0.00	$0.64	$1.34	$0.00	$0.00	$0.00
% Reduction in State Taxes due to Incentives	53.3%	0.0%	70.6%	59.3%	34.7%	43.6%	38.6%	0.0%	17.9%	35.3%	0.0%	0.0%	0.0%
Average Cost of Electricity (ACOE) $/MWh	**$49.67**	**$60.63**	**$30.31**	**$44.32**	**$30.23**	**$60.59**	**$28.32**	**$32.07**	**$47.92**	**$46.22**	**$51.86**	**$31.04**	**$34.72**
Assumed Capacity Factor	$0.37	$0.42	$0.50	$0.41	$0.51	$0.34	$0.51	$0.51	$0.41	$0.38	$0.41	$0.51	$0.51
Assumed Regional Cost Difference	$0.96	$1.22	$0.94	$0.98	$0.96	$1.04	$0.92	$0.92	$1.05	$0.96	$1.06	$0.94	$0.94

Table A2: State Cost Components assuming a 30-year Project Life at 35% Capacity Factor and no Regional Cost Differences

	Arizona	California	Colorado	Idaho	Montana	Nevada	New Mexico	New Mexico (w/o IRB)	Oregon	Utah	Washington	Wyoming	Wyoming w/ $5 Wind Tax
System & Federal Taxes $/MWh													
System Cost	$20.15	$20.15	$20.15	$20.15	$20.15	$20.15	$20.15	$20.15	$20.15	$20.15	$20.15	$20.15	$20.15
Federal Tax Credits	($4.80)	($4.80)	($4.80)	-$4.80	($4.80)	-$4.80	($4.80)	($4.80)	($4.80)	($4.80)	-$4.80	($4.80)	($4.80)
Financing Cost	$19.31	$19.32	$18.62	$18.89	$17.74	$18.44	$16.37	$19.18	$17.73	$17.74	$19.42	$18.77	$18.77
Operating Costs	$16.44	$19.86	$16.10	$16.66	$16.28	$17.40	$15.80	$15.90	$17.46	$16.28	$17.77	$16.12	$16.12
Federal Income Taxes	$2.12	$2.09	$2.03	$2.03	$1.92	$2.00	$1.88	$2.15	$1.80	$1.80	$2.23	$2.13	$2.11
Pre-State Tax Total	**$53.22**	**$56.62**	**$52.09**	$52.92	**$51.28**	$53.19	**$49.40**	**$52.57**	**$52.33**	**$51.16**	$54.77	**$52.37**	**$52.35**
State Taxes Before Incentive $/MWh													
Sales Taxes (financed)	$1.11	$1.14	$1.01	$0.82	$0.00	$1.08	$1.02	$1.02	$0.00	$0.91	$1.20	$0.73	$0.73
Property Taxes	$4.12	$2.49	$5.32	$4.10	$3.93	$4.59	$2.77	$2.86	$3.54	$3.06	$3.21	$1.91	$1.91
Income Tax	$0.69	$0.87	$0.43	$0.70	$0.57	$0.00	$0.67	$0.75	$0.55	$0.42	$0.00	$0.00	$0.00
Gross Receipt Taxes	$0.00	$0.00	$0.00	$1.68	$0.00	$0.07	$3.17	$3.57	$0.00	$0.00	$0.26	$0.00	$0.00
Excise Taxes	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.92	$4.62
State Taxes w/o Incentives	**$5.92**	**$4.50**	**$6.76**	$7.29	**$4.50**	$5.74	**$7.63**	**$8.19**	**$4.08**	**$4.39**	$4.68	**$3.56**	**$7.26**
State Taxes After Incentives $/MWh													
Sales Taxes	$1.11	$1.14	$0.62	$0.82	$0.00	$0.50	$0.33	$1.02	$0.00	$0.00	$1.20	$0.73	$0.73
Property Taxes	$1.03	$2.49	$1.16	$0.00	$2.57	$2.67	$1.04	$2.86	$2.83	$3.06	$3.21	$1.91	$1.91
Income Taxes	$0.69	$0.87	$0.43	$0.70	$0.57	$0.00	$0.67	$0.75	$0.55	($0.11)	$0.00	$0.00	$0.00
Gross Receipt Taxes	$0.00	$0.00	$0.00	$1.68	$0.00	$0.07	$3.17	$3.57	$0.00	$0.00	$0.26	$0.00	$0.00
Excise Taxes	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.92	$4.62
State Taxes w/ Incentives	**$2.83**	**$4.50**	**$2.21**	$3.19	**$3.14**	$3.24	**$5.21**	**$8.19**	**$3.38**	**$2.95**	$4.68	**$3.56**	**$7.26**
Reduction in State Taxes due to Incentives	$3.09	$0.00	$4.55	$4.10	$1.36	$2.50	$2.42	$0.00	$0.71	$1.44	$0.00	$0.00	$0.00
% Reduction in State Taxes due to Incentives	52.2%	0.0%	67.3%	56.2%	30.3%	43.6%	31.7%	0.0%	17.3%	32.8%	0.0%	0.0%	0.0%
Average Cost of Electricity (ACOE) $/MWh	**$56.05**	**$61.12**	**$54.31**	**$56.11**	**$54.42**	**$56.43**	**$54.61**	**$60.76**	**$55.71**	**$54.11**	**$59.44**	**$55.93**	**$59.60**
Assumed Capacity Factor	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Assumed Regional Cost Difference	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

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