# State Incentives: Impact on Wind Energy Costs and Policy Development

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**Abstract**

Wind energy presents significant opportunities for states to foster economic growth, generate tax revenue and aid the transition from fossil fuels. Policymakers considering new incentives to attract wind energy projects are challenged by a lack of modern information on the relative cost of wind development and how it is impacted by such policies. Previous research regarding the impact of incentives is limited, dated and often contradictory. This study addresses this information gap by developing a detailed cost model to evaluate wind development costs across the western United States. Despite nearly equivalent wind resources, results indicate New Mexico has costs between 11.7 and 15.9 percent lower than Montana, Colorado and Wyoming, the next lowest-cost states. This advantage occurs due to a unique bonding incentive and despite a tax burden higher than all but Wyoming's. Cost patterns are consistent with observed development patterns over the past decade, suggesting understanding state incentive impacts on relative development costs can aid design of more effective programs to attract development. Findings also suggest understanding the cost structure of wind developments is crucial to resolving contradictions in previous econometric studies. Examples are presented to demonstrate how cost models can serve as testbeds to identify more attractive development policies while avoiding reduced state revenues, and how lesser used programs like bonding can significantly reduce development costs to attract greater wind energy development. The methodology presented can be adapted to other regions, providing a tool for policymakers to increase renewable energy development and aid in achieving sustainable development goals.

**Keywords: Wind energy development, renewable energy, regional economic development policy, incentive design, cost modeling**

**Abbreviations:**

ACOE
Average Cost of Energy
AZ
Arizona
CA
California
CO
Colorado
GCF
Gross Capacity Factor
IRA
Inflation Reduction Act
IRB
Industrial Revenue Bond
ID
Idaho
ITC
Investment Tax Credit
kWh
Kilowatt Hour
MACRS
Modified Accelerated Cost Recovery System
MWh
Megawatt Hour
MT
Montana
NM
New Mexico
NCF
Net Capacity Factor
NV
Nevada
O&M
Operating and Maintenance
OPEX
Operating Expenditures
OR
Oregon
PILOT
Payment in Lieu of Taxes
PTC
Production Tax Credit
RPS

Renewable Portfolio Standards

U.S.
United States

USACE
U.S. Army Corps of Engineers

UT
Utah

WA
Washington

WECC
Western Electricity Coordinating Council

WY
Wyoming

w/o
Without

**Highlights**

- A model of the financial structure of typical utility-scale wind development is defined.
- Incentive policy impacts on developers' costs in western states are identified.
- Results resolve ambiguities in previous wind development incentive policy literature.
- Results are consistent with current development patterns in the western U.S.
- Results suggest comparative development costs are essential drivers of wind location.
- Use of cost modeling is suggested for use to testbed incentive policies under consideration to determine impacts on comparative costs to other states/regions, impact on developers' costs and impacts on state/local revenues.

## 1. Introduction:

Wind energy offers a major economic development opportunity for many rural communities where it can create new economic growth and tax revenue, and aid in the transition from legacy fuels [1]. In fossil energy producing areas, wind development can also promote a more resilient economic base and local government revenues if it unties a community from volatile energy sector commodity prices. In the United States in the post-COVID era, federal programs including the IRA have been implemented to expand renewable energy development both to meet climate goals and to specifically target rural economic development [2]. Federal renewable energy incentives are available to all U.S. states, thus states and communities interested in attracting new wind energy projects have enacted or are actively considering local tax and incentive policies to increase their competitiveness to entice such development [3], [4]. Optimally, such policies would maximize their effectiveness to attract development while minimizing their cost. Designing such policies, however, is complicated by a lack of modern information regarding the relative cost of wind development by state, and because estimates of how various incentive policies can affect a state's cost-competitiveness to attract wind development are lacking.

This study improves the information gap on wind generation tax and incentive policies by demonstrating the implementation of a detailed cost model of wind capacity development to determine which states are most cost competitive and how various incentives may affect this competitiveness. The model is calibrated to U. S. states in the WECC, which spans the western half of the continental United States and where there is significant interest in wind development [5]. The results of this modeling exercise show how various incentives and tax policies currently in place across the WECC change state's average relative costs of new wind generation. Results also are consistent with observed wind development patterns in the region over the past decade, suggesting that understanding state incentive impacts on relative development costs can aid in the design of more effective programs to attract new development.

In addition, results show how cost modeling can be used to inform and design more effective tax and incentive policies to increase a state's development competitiveness. As examples, existing state incentives are compared to determine their impact on development costs. Alternative wind-tax structures are considered, and a specific hypothetical change is constructed for the state of Wyoming to demonstrate how redesigning existing incentive policies can result in lowering the cost of wind development while simultaneously increasing tax revenues, avoiding the traditional tradeoff between incentivizing wind development and creating additional revenue generation. Such cause and effect estimates on costs and revenues for a specific policy change would be very difficult to develop without the use of a cost model as described here. Such modeling is almost unknown in the renewable energy policy literature and the methods and results of this study can be adapted to other regions to give policymakers a tool for exploring how different policies balance the benefits and costs of wind-energy development.

Wind development creates both short- and long-term economic benefits. Short-term benefits accrue to communities during construction through demand for construction materials, labor, and other local goods and services [6]. Long-term, wind facilities create additional local employment and demand for materials, equipment, and services through continued operation and maintenance. Where they displace fossil-fuel plants, they may also create local environmental ([7], [8]) and health benefits [9]. Local public revenues may also be enhanced through new property, sales, income, or other taxes and payments [10], [11]. For this reason, the costs of implementing incentives or foregone revenues used to attract such activity may be seen as an investment in economic development. Wind generation, however, also creates local costs. Expansive land use may lead to ecological, cultural, aesthetic, and resource costs [12]. Wind development may also affect local property values [13]. Increased economic activity caused by wind development may also increase demand for local services, requiring additional revenues to maintain service quality.

Economic benefits and costs and related tax policy pose a tradeoff to communities considering wind development [11]. Reducing the tax burden to encourage wind development may reap economic benefits but such benefits are often private and greatest in the short term. Alternatively, the existence of local public and non-pecuniary costs and externalities may encourage taxing wind generation activities, especially when power is exported, as taxation can transfer local costs to the end-users. Taxing wind generation activities may also create new local revenues, and/or replace others that may decline during the current energy transition. Increased taxes, however, may also harm regional competitiveness in attracting wind investment.

Local taxes and incentives can affect which regions attract wind investment due to their effect on developers' costs. In some cases, by changing tax and incentive policies, it may even be possible for a state to increase its attractiveness for development by reducing project costs, while also increasing fiscal revenues, thereby avoiding any development/taxation tradeoff [11]. Optimally, states considering incentive programs for wind development would understand how different taxation and other incentive decisions create advantages or disadvantages in attracting economic development before they are implemented [14]. Specific estimates of the tax elasticity of wind development are undeveloped and while studies of comparative development costs in the presence of state-specific incentives exist (see [15], [16]), they are now dated.

Past survey and econometric studies in the academic and policy literature have attempted to determine what types of incentives are most effective in attracting development but conclusions from these studies are now dated and sometimes contradictory. To address policymakers' needs to understand the potential impacts of any tax or incentive decisions, this study explores the potential benefits of using a detailed cost model describing the financial structure of typical utility-scale wind development to determine how changes in local and state taxation and incentive policies affect developers' costs across states in the WECC region of the U.S. Though previous results discussed and new ones presented here focus on how incentives have and can affect wind-energy development in the western United States, the principles considered are applicable well beyond the United States and renewable energy development and can be applied anywhere consideration is made to use tax incentives to attract large private economic development projects.

The paper is structured as follows: conclusions from previous seminal studies that attempt to discern the effects of tax and incentive policy on wind development *ex-post*, by observing tax and development outcomes after they occurred, are summarized and potential shortcomings to the approach used in these studies are then considered. These results are then compared to the pattern of wind development that has occurred across WECC states over the past two decades to determine if the data can shed light on the continuing relevance of previous findings, while also describing the landscape any new approach must be able to satisfactorily explain. State incentives in the WECC region are then described, using current state and federal tax laws and wind-development incentives as they were written in Spring 2023. The construction of the cost model employed here is then outlined, focusing on a description of the capital structure of a wind facility to understand how taxation and other policies may affect wind development incentives through costs *ex-ante*, before they occur, and paying particular attention to the potential explanatory advantages of a cost-modeling approach. Results are consistent with recently observed development patterns. A comparative analysis of current state-specific development costs is then conducted, and the effects of different taxes, subsidies, or other financial incentives are evaluated using this model to determine which ones have the greatest influence on developers' costs and therefore a state's cost-competitiveness. Finally, a simple experiment comparing current incentives in the state of Wyoming to an alternative case is described to demonstrate how modeling costs before they occur can be used to affect a state's competitiveness to attract development, optimize tax and incentive decisions and affect the potential tradeoff between attracting local development and total lifetime tax revenues from such project. More generally, by changing tax and incentive assumptions in the model, such an approach can be calibrated to new regions and used to conduct scenario analyses under many different assumptions to improve policy anywhere.

## 2. Previous Literature and Changing Wind Development Patterns in the WECC

Prior work on the determinants of U.S. renewable energy development has often focused on national policy incentive impacts on wind development, finding that federal investment and production tax credits have been effective and impactful [17], [18]. Given these incentives are available in all states, they do not determine individual state competitiveness to attract wind generation. State-specific policy effects have been more challenging to identify and may be of two types. The first type are demand-side mandates that require a certain amount of generation to be from renewable sources, most commonly enacted through the use of RPS. The second form of incentive can affect the supply-side, using tax and/or production incentives to influence the cost of renewable energy, incentivizing construction by reducing developers' costs where they apply. There are a large number of studies that consider demand-side policy effects, but relatively few that consider specific supply-side effects like tax and production incentives.

Summarizing the results of the previous literature, a strong consensus finds demand-side RPS mandates a powerful influence on wind deployment. Many, but not all these studies have controlled for non-policy factors such as local wind resource and transmission access, both of which have also been found to positively influence wind development. The earliest of these papers consider early development up to 2003 [18], [19], while [20] extends the period of consideration to 2006, and [21] considers a period from 1990 to 2011. The most recent study [22] considers a period from 2009 to 2019. Each study finds RPS and similar mandates a significant influence on wind energy deployment.

Less consensus is found for the effects of supply-side policies, where there are very few studies that consider different tax or production incentives and their impact on wind energy development. Attempts to identify the effects of state-specific supply-side incentive policies have shown mixed results and occasional contradictions based on methodology, econometric specification and data definition. For example, considering a comparative survey of policies across twelve U.S. states through 2003, [18] found that property and sales tax exemptions may positively influence wind development, though they conclude that these policies may not stimulate new wind development alone. Using econometric methods [19] finds such incentives did not significantly influence wind generation development in thirty-nine states from 1998 to 2003. Considering the same states and time-period, [20] identified and addressed limitations in the methodology in [19] and found the opposite; that state taxes and subsidies were important in determining wind development. Considering county instead of state-level data, [23] used econometric methods to quantify the impact of incentives on wind capacity additions in the U.S. from 1998 to 2007. Corporate tax credits, sales tax incentives, and production incentives all had positive, significant effects on wind development, but property tax effects could not be identified. Additionally, the study found sales and corporate tax credits had similar impacts per dollar spent, while production incentives were about 2.5 times more cost-effective in stimulating wind development. Considering the period spanning 2009 to 2019, [22] finds financial and production incentives provide weaker incentives for development, while finding contradictory results to [23] with respect to taxes. Sales tax incentives were found not to significantly affect wind capacity additions, but property taxes were found to have a significantly positive impact.

When well-designed, the use of econometric methods can identify statistically significant causal relationships between variables that are crucial for understanding the impact of policy changes or other economic events. For this reason, such methods are used to document causal relationships across a wide range of applications. Such stable causal relationships, however, can be difficult to identify in policy contexts, which may explain why so few studies exist that consider supply-side cost incentive effects on wind deployment. Overall, econometric methods like those employed in [19] through [23] identify mixed results for the impacts of state-specific supply-side incentive policies on renewable energy development. Financial and tax incentives can meaningfully affect wind development location, but previous results are unspecific and sometimes contradictory regarding which types of incentives may be most effective. The lack of a consensus regarding the effects of these incentives may be due to the econometric methodology employed. Observing the differences in findings of various studies attempting to answer the same question - how state incentives affect wind development choices, [24] notes such differences are likely due to the difficulty in capturing necessary comparative detail in state policies using econometric methods to understand the relationships in question:

> *The energy policy literature contains few analyses that explore the effects or effectiveness beyond this general understanding of the pros and cons of state tax incentives. Tax incentives are likely under-researched because of the immense variation in their design across locations, which makes empirical evaluations of their effects difficult. Additionally, tax incentives are often*

> *implemented in conjunction with other instruments, which makes it difficult to tease out the effects of one instrument from the effects of the other in empirical evaluations.* (pg. 277)

Empirical evaluation of the effectiveness of tax or production incentives is challenged through the way many of these studies define the policy variables in their econometric studies. Not only do tax incentives differ in design by location, but tax regimes also differ by state, influencing their potential impact on developers' costs for a given level of incentive. Of the studies considered here, only [23] considers sales, property and corporate tax effects separately as implemented by state, allowing evaluation of the comparative effectiveness of these incentives on wind development across states. The other studies group such incentives together as one binary variable indicating the presence of any such policy ([19], [22]), or create an index value that does not consider such policies separately [20], thus inferences are limited to whether tax incentives may affect wind development generally and which are most effective. The problem of multiple policy instruments being present is also a challenge. Only [21] attempts to consider combined effects of policies, specifically the joint effect of federal PTCs and state specific policies, but again the study does not differentiate between potential types of state-specific incentives. Overall, as [24] notes, the previous econometric literature provides policymakers little guidance regarding how to design incentive programs beyond understanding potential pros and cons of doing so.

Given the dated nature of many of these studies, it may be reasonable to consider whether causal inferences previously identified still hold and whether demand-side policies still appear more effective. To consider these questions, results from past literature are compared to WECC development patterns over the past twenty years to determine and evaluate the applicability of previous conclusions. The WECC comprises the eleven states in the western United States and the Canadian provinces of Alberta and British Columbia that make up the Western Interconnection, one of four separate power grids, each with limited power transfer capacity between them, that span these two countries. While previous studies have been national in scope, they did not control for specific market regions within which states may compete for economic development using incentive policy. Given the construction of the U.S.-Canada grid and the WECC region within it, the WECC region can be assumed to be a single market area that defines a potential set of U.S. states competing with one another for wind development. This makes it a good candidate region to test whether previous conclusions are supported by recent development patterns observed. Canadian provinces within the WECC are not considered because of the limited power transfer capability between them and the rest of the WECC thus they could be considered outside the market area defined by the eleven states considered. Similarly, other states outside the WECC are also not considered due to the limited transfer capability between the WECC and adjacent grid regions [25].

State RPS mandates have unanimously been found in previous econometric studies to be powerful influences on the location of development but may now be an example of how such inferences are no longer be relevant in a more modern context. Most existing literature relies on data that is dated, and results using such data describe time-periods when the cost of wind technology was not competitive with other forms of generation. Figure 1 shows the comparative costs of the three most common forms of generation in the WECC between 2009 and 2022. Lazard [26] estimates median unsubsidized wind generation costs fell by 72 percent between 2009 and 2021. The median estimated cost of new wind generation has been below median new coal and gas generation costs since 2011. Since 2016, even the high estimate of wind generation cost has been below the median estimated cost of new natural gas generation in the U.S., making new wind generation less costly than most new fossil fuel generation and even most existing, fully depreciated coal generation [26], [27]. Such a development would make RPS mandates no longer necessary, as such mandates were originally instituted to force wind development when it was the least preferred source of generation by cost, instigating such development when it would not have been otherwise undertaken.

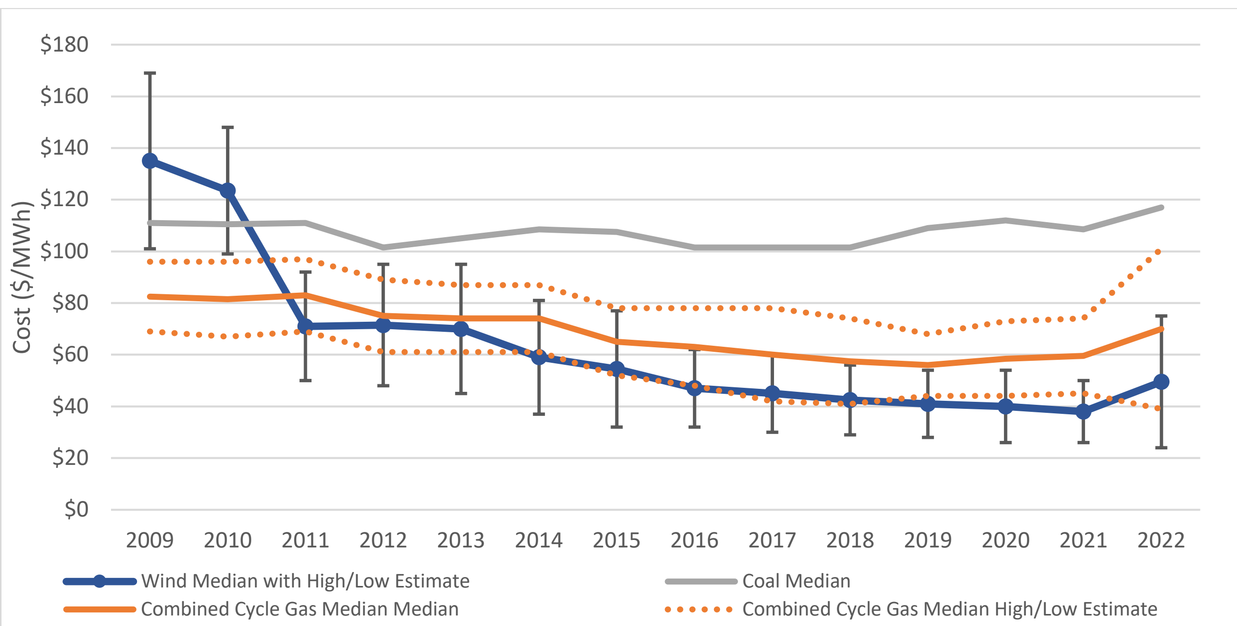


**Figure 1:** Estimated Median and High/Low Unsubsidized Wind Levelized Cost, with Comparison to Traditional Sources (2009 to -2022). Source data: [26]

Reviewing patterns of wind development by WECC state using aggregate development data suggests early wind development patterns (greater than ten years old) were consistent with the finding in previous research that RPS were very important in determining locations of wind projects. Patterns over the past decade, however, also suggest mandates may no longer be as relevant. Figure 2 shows total wind generation capacity for each WECC state by vintage while Figure 3 shows existing and planned wind capacity additions in WECC states. Generation capacity greater than ten years old is concentrated in California (CA), Oregon (OR), Washington (WA) and Colorado (CO) where RPS standards were adopted in the early 2000's, while the newest capacity (four years old or newer in Figure 2) is located in New Mexico, (NM), Colorado, Wyoming (WY) and Montana (MT). New planned development as shown in Figure 3 is concentrated in Wyoming, New Mexico, and Montana. Notably, Wyoming and Montana have no RPS or clean energy standards. Overall, most recent development appears unrelated to whether states have RPS mandates. Given current cost of generation trends over the past decade, this again suggests mandates may no longer be necessary to spur wind development. Instead, developers may now pursue projects based on relative development and production costs by state, which can be influenced by state incentives, along with other factors such as state-specific wind resources and cost of construction.

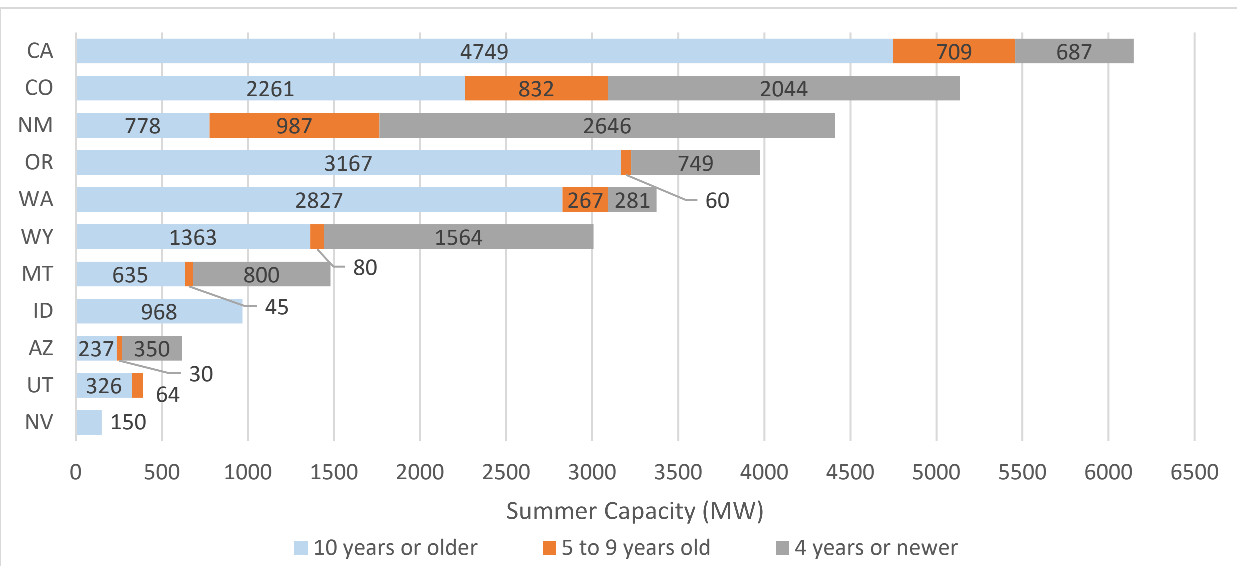


**Figure 2:** Existing Wind Generation Capacity by Vintage across WECC States, Source data: [28].

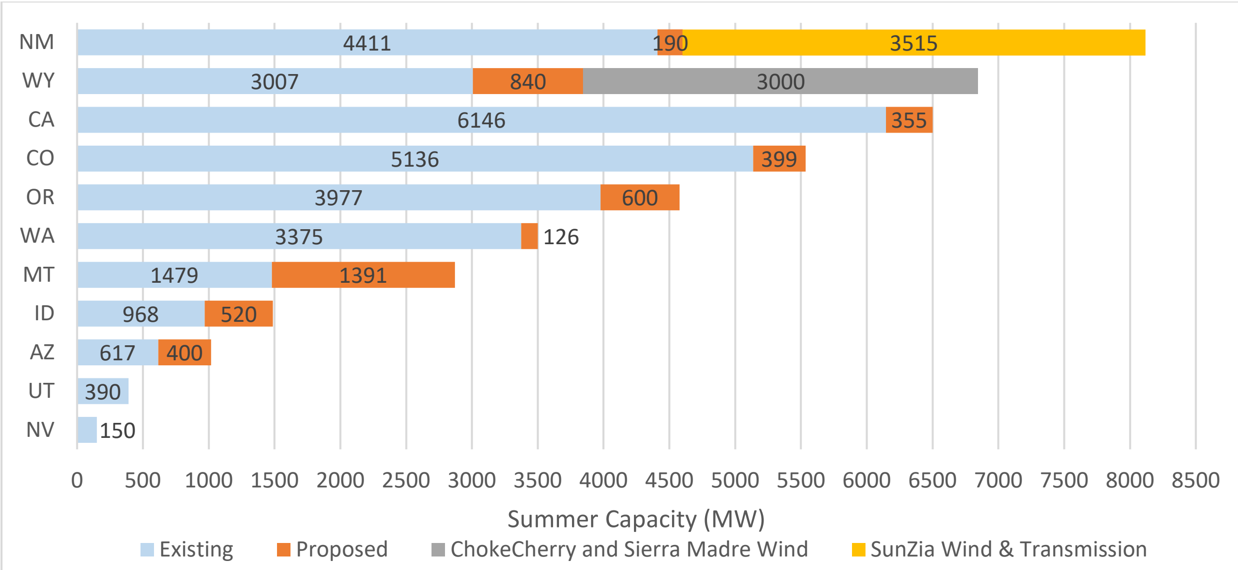


**Figure 3:** Existing and Planned Wind Generation Development across WECC States, Source: [28]

On a per-unit of electricity generated basis, productivity would be a significant influence on cost. Figures 4 and 5 show average capacity factors from 2019 to 2022 for all facilities built since 1998, and for all facilities built since 2018 respectively. Capacity factor is a measure of productivity, describing the percentage of total generation capacity possible that is achieved at a wind generation site. Better wind resources cause higher capacity factors to be achieved for the same quality of technology and therefore lower the cost of generation. Capacity factor outcomes over time across all states have increased due to improvements in technology, which has allowed greater productivity and reduced the cost per unit of electricity generated across all states, as shown in Figure 1. Technology has had less influence in changing the relative capacity factors between states. Relative differences in capacity factor by state in both Figures 4 and 5 are due mainly to differences in state wind resources. Those with better resources will have higher capacity factors and lower cost of production than those states with lesser resources and therefore will be more attractive for development.

Results presented in Figures 4 and 5 clearly indicate regardless of vintage, the top four states for capacity factor have been New Mexico, Colorado, Wyoming and Montana. These are also the four states with the greatest amount of new development over the past four years, and the greatest planned development in the future as shown in Figures 2 and 3. The pattern of production over time has moved from states with relatively lower resource quality but with RPS standards to those with the highest quality wind resources. Again, this suggests that RPS standards have become less relevant and that cost (supply-side) factors, specifically the quality of the wind resource, may now be more important in determining site location, as highlighted in more recent development studies [29].

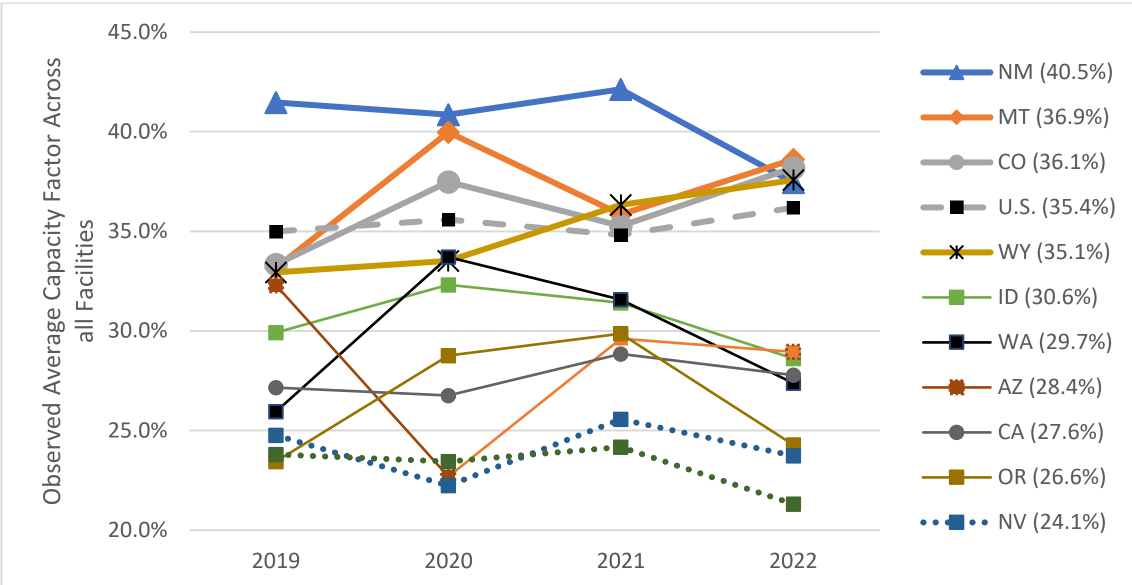


**Figure 4:** Observed Average Capacity Factors by State – all facilities built since 1998. Source data: [30]. Parenthetic values indicate the four-year average annual capacity factor achieved by the state.

Against this background, rural eastern states in the WECC with good wind resources (New Mexico, Colorado, Wyoming and Montana) may now face an opportunity to utilize energy-based economic development by expanding wind generation capacity [31], despite the fact that they are far from major population centers. As shown in Figure 3, two very large projects under construction, the SunZia and ChokeCherry projects in New Mexico and Wyoming will significantly increase the amount of wind generation not only in these two states, but will be among the largest wind facilities in the world and largest in North America. The scale of these two projects has been used to support the costly transmission line projects associated with them to export power to distant markets and are indicative of how wind development has been proceeding in the WECC in recent years. Excellent wind resources located in sparsely populated areas have been developed to export power to more populous regions in the west such as Los Angeles CA, Phoenix AZ, Denver CO, Seattle WA, Portland OR, Boise ID and Salt Lake City UT. Where transmission capacity is limited, as in the cases of the SunZia and ChokeCherry projects, very large project sizes allow economies of scale to reduce the unit cost of adding new transmission infrastructure.

In some cases, capacity factor by state has increased, not due to a change in resource, but because of an increase in available transmission infrastructure and improvements in installed generation technology.

Such changes can lower generation costs by eliminating transmission constraints, which reduce transmission congestion and the need to curtail wind plant generation, increasing productivity. Wyoming demonstrates this in Figure 4, where, after a local utility embarked on a major infrastructure upgrade that included adding transmission capacity and updating older turbines to newer, more productive units, capacity factor increased from older facilities from 2020 to 2022. As federal renewable energy support programs like those found in the U.S. IRA, and new federal programs that target infrastructure development like the U.S. Infrastructure, Investment and Jobs Act are enacted, it could be expected that more transmission and generation development and upgrades will occur. This is likely to incentivize states to compete for such funding as a source of economic development, especially among those states with the best wind resources. When resources are very similar, state and local financial incentives may become very important in determining the location of future wind developments across states.

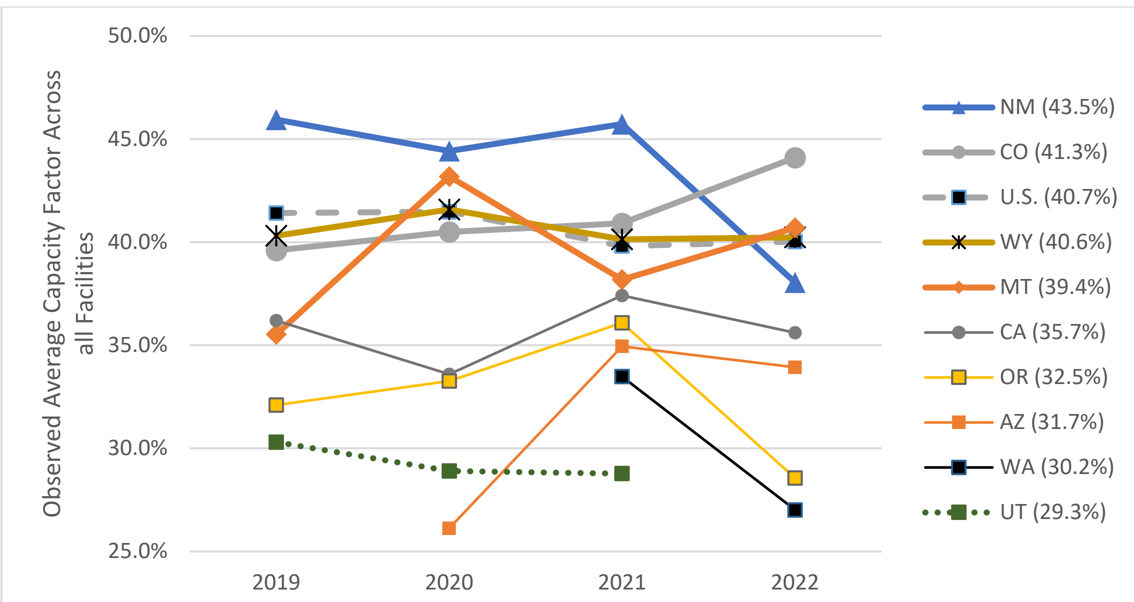


**Figure 5:** Observed Average Capacity Factors by State – all facilities five years old or newer. Source data: [30]. Parenthetic values indicate the four-year average annual capacity factor achieved by the state.

### 3. Federal and State Financial Incentives

A variety of federal and state-specific incentives exist for wind energy in the United States. A federal ITC has been available for wind developers since 1978, while a PTC was created in 1992. For wind development, the most influential of these has historically been the PTC. First instituted as part of the Energy Policy Act of 1992, these inflation-adjusted tax credits were originally worth \$0.015 in 1993 for each kWh of qualifying renewable production (\$15 per MWh). Project eligibility for the tax credit is typically based on the year a project begins construction. Since its inception, the PTC program has been renewed eleven times and has expired six times. These stops and starts have caused yearly wind capacity additions to exhibit a boom-bust cycle over time with the availability or expiration of federal PTCs [5]. The U.S. IRA, enacted in 2022, extended the PTC through 2024, specifying an inflation-adjusted credit of $0.026 per kWh ($26 per MWh) for the first ten years of electricity generation. The IRA also added a potential bonus credit of up to 20 percent for the federal PTC if domestic content thresholds are met or facilities are located in fossil fuel-dependent "energy communities". The PTC program will be replaced by low-carbon electricity generation credits in 2025 as mandated by the U.S. IRA.

The federal PTC program is often misunderstood. The tax credit is non-refundable, and 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. 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 the 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 program's value has primarily been to reduce the cost of project financing for wind developers.

While federal incentives are available to all developers, states have also offered various policies to incentivize wind power development within their borders. Demand-side mandates are present in eight of the eleven WECC states with all but Wyoming, Idaho (ID), Montana and Utah having an RPS mandate. Utah has a voluntary renewable energy standard. Supply-side programs directly affecting a wind facility's cost are also available across states. They 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 as *payment in lieu of taxes* (PILOT) programs. Table 1 summarizes the state-specific tax rates and exemptions available among WECC states for wind development as of 2023. 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 per MWh of wind-generated electricity.

General tax regime differences also can affect wind development location incentives by reducing a project's taxes payable. Table 1 describes how average total state and local sales taxes differ. Three states (Wyoming, Nevada, and Washington) do not have corporate income taxes, while Nevada, Oregon, and Washington instead assess a gross receipts tax. Six states have exemptions from corporate income and business taxes applicable to wind development. Montana and Oregon do not assess sales taxes. Seven additional states have sales tax exemptions available for wind energy, including two that entirely exempt wind from sales taxes (Colorado and Utah). Washington has an exemption from all sales taxes if a project meets specific wage criteria. Additionally, county or local sales taxes can differ from the state level in some states.

WECC property taxes differ by state and county, and are affected by state-specific exemption policies. Calculation of property taxes on wind facilities may differ from other forms of property, 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. 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 gross revenue approach. Idaho has exempted all wind generation property from taxation and has instead instituted a gross receipts tax of 3 percent in lieu of a property tax. Oregon, Nevada, and New Mexico have negotiated property tax relief often unique to the project and location.

Other financial incentives are also available in two WECC states. Utah allows economic development tax credits in defined areas. New Mexico regularly offers financing for large capital-intensive projects including wind facilities, using IRBs to reduce financing costs. This scheme allows the local county to own and finance the project through its bonding authority, leasing the project back to the developer. This allows the developer access to lower cost financing as the bonds issued by county or municipal agencies have lower interest rates. Such a program also makes the county a part owner in the project. Counties are often tax-exempt entities, thus projects utilizing such funding negotiate payments in lieu of property and county sales taxes payable on a case-by-case basis. This form of incentive is referred to as a PILOT program. While technically other states like Wyoming also have the authority to use such bonding, to date New Mexico has been the only WECC state to use such an incentive. New Mexico also allows a community development incentive wherein counties may exempt up to 100 percent of assessed property taxes for twenty years.

**Table 1:** Summary of WECC State-Specific Taxes and Incentives Applicable to Wind Projects

| | 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 | Specific Wind Taxes | Other Incentives/ Subsidies |
|---|---|---|---|---|---|---|---|---|---|---|
| Arizona | 4.9% | N.A. | - None. Two programs for new generators, and self-consumption ended in 2021 and 2018, respectively. | 5.6% (6.5825%) | -exemption on sales and purchase or rental of equipment to build facility over $20 million. | -assessment based on 20% of depreciated facility value | -wind equipment full cash value assessment discounted by 80% | straight-line, 20-year, 10% floor. | No | No |
| California | 8.84% | N.A. | No | 7.25% (7.99%) | -limited to non-generation equipment | - 1% tax rate on depreciated facility value | No | straight line, 20-year, 20% floor. | No | No |
| Colorado | 4.4% | N.A. | No | 2.9% (4.15%) | -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 | straight-line, 20-year, 15% floor. | No | No |
| Idaho | 5.8% | Wind energy Production tax of 3% on gross wind energy earnings | - 3% of federally qualified investments for investment tax credits, up to 50% of tax liability | 6% (6.0%) | - 25% tax rebate of all sales/use taxes paid on property constructed during project period | - Idaho exempts property of wind energy producers from taxation. In lieu of the ad valorem property tax, the Wind Energy Production Tax of 3% of producer's gross earnings is imposed. | | | | |
| Montana | 6.75% | N.A. | No | 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 next 5 years until gone | straight-line, 20-year, 15% floor. | No, but state assesses a 15 cent/MWh generation tax on all generation sources | No |
| Nevada | N.A. | -0.136% of Nevada gross revenue exceeding $4 million | -Revenues from power exported from the state would be exempt | 4.6% (7.725%) | -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 | straight-line, 20-year, 0% floor. | No | No |
| New Mexico** | 5.9% + $24,000 on net income over first $500,000 | State: 4.875% Average across wind counties: 5.73% | - Deduction for receipts from selling facility to a government when combined with Industrial Revenue Bonds | 4.875% (5.73%) | If gross receipts tax paid elsewhere, exempt from taxes applied at point of sale | -assessment based on 33.33% of depreciated facility value, taxed at 2.6666% (state average) | -taxes negotiable if industrial revenue bonding is used. 100% exemption excluding school district fees for 20 years if IRBs not used | straight-line, at 3.2% rate down to 20% floor. | No | -local industrial revenue bonding may be negotiated. |
| Oregon | 6.6%, 7.6% on taxable income above $1 million | 0.57 applied on all state sales, allowed 35% deduction for costs | No | N.A. | -no sales tax in the state | -assessment based on depreciated facility value, taxed at 1.5% | Development in rural renewable energy zones may get 3-year 100% exemption | straight-line, 20-year, 20% floor. | No | |
| Utah | 4.65% | N.A. | - $3.50/MWh refundable production tax credit in first four years | 4.85% (6.26%) | -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 | straight-line, 20-year, 20% floor. | No | Economic development tax credits in enterprise zones or for significant job creation |
| Washington | N.A. | -Public Utility Tax: 3.8734% of gross receipts | - Can deduct sales of electricity for use outside the state | 6.5% (8.1%) | - 50% to 100% exemption on new equipment and labor if project certified by Dept. of Labor and Industries | -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% (5.5%) | No | -assessment based on 11.5% of depreciated facility value, taxed at 6.8% (state average) | No | straight-line, 20-year, 20% floor. | $1/MWh | No |

Some incentives will be more valuable than others due to their impact on overall project costs. For example, wind facilities are highly capital intensive and incentives that reduce total financing costs may be more valuable than other tax reductions. It is therefore essential to understand the capital structure of a renewable energy facility to understand how financing incentives and different types of tax exemptions affect the overall lifetime cost of the project, especially if the goal in designing tax policy is to attract such development. The following section describes a modeling framework that decomposes the various components of cost at a wind facility to determine the relative cost competitiveness of wind generation in each WECC state. Optimally, states considering incentive programs for wind development will understand how different incentives affect costs and impact location decisions. No comprehensive studies of comparative state development costs in the presence of state incentives exist in the academic literature, and the use of such a cost model and resulting estimates could be very beneficial to policymakers.

**4. Cost Modeling Framework: Cost Model Inputs and Logic**

An alternative approach to using econometric studies to consider the potential effect of state financial incentives on wind development is directly modeling the comparative cost of wind development across states, specifically describing how tax incentives affect the specific costs of a wind project in a particular location. While an advantage of econometric modeling is the ability to isolate and identify statistically the specific causal effects for the change of one variable on another, to be effective such studies should first model how costs are determined and how they affect choice of a project location. Previous econometric studies have not developed such models and are therefore silent on how such policies affect wind project cost structures beyond broad inferences. Additional to that, as previous studies have noted [24], capturing the variations in design of state incentives, and how they interact with other incentives makes empirical evaluation of the effectiveness of state incentives very difficult. Both of these criticisms can be addressed if costs are modeled directly. Cost models allow better precision in the description of state policies and how such policies affect the cost of generation. Cost models also directly identify how such policies interact with other incentives to describe directly how such programs can affect the cost of wind development and the relative costs of development across states.

The most used energy development cost metric is the levelized cost of energy. This measure sums all expected costs over the lifetime of a generator and compares them to expected lifetime energy output to compute the average cost of each unit of electricity produced, expressed in dollars per MWh. The levelized cost measure developed here is referred to as the average cost of energy (ACOE) for each of the eleven

WECC states assuming an identical wind facility. Tax and incentive differences across states, as well as wind resource and regional construction cost differences are then used to show how they affect the computed relative cost competitiveness of each state to attract wind energy. 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.

**Table 2:** State Cost Adjustment Factors

| **State** | **2023 Cost Adjustment Factor** (1.00 = National Average) |
|---|---|
| **AZ** | 0.95 |
| **CA** | 1.23 |
| **CO** | 0.93 |
| **ID** | 0.97 |
| **MT** | 0.94 |
| **NM** | 0.90 |
| **NV** | 1.08 |
| **OR** | 1.07 |
| **UT** | 0.96 |
| **WA** | 1.07 |
| **WY** | 0.93 |

Source: [32]

Modeling costs in detail allows an understanding of how incentives such as tax credits and exemptions affect costs not only through the direct tax cost reduction, but also through their impact on financed costs. To show the effect on financed costs requires a specific description of the financing of a wind development, often referred to as a project's capital structure. This allows a description of how cost results change with wind resource quality, construction and equipment costs, interest rate assumptions, and due to any financial incentives states may offer. To develop specific state cost estimates requires background information as summarized in Tables 2, 3, and 4 in addition to state financial incentives described in Table 1. In addition to these costs, operating and finance cost assumptions must be identified. These include fixed and variable operating costs of the project once in operation, often referred to as O&M costs, and the assumed inflation rate of these costs over the operating life of the facility being modeled. All of these types of assumptions are described in Tables 2 and 3. Finally, resource quality assumptions are needed, as described in Table 4.

**Table 3:** Facility Cost Calculation Assumptions

| Cost Factor | Assumed Value |
|---|---|
| **Output capacity**[a] | 300 MW |
| **Total capital costs**[a] | 1511 $/kW |
| **Share of system costs subject to sales tax**[c] | 67% |
| **Fixed O&M annual cost**[a] | 26 $/kW |
| **Fixed O&M inflation**[a] | 4.5% |
| **Variable cost**[a] | 0 |
| **Capacity factor degradation rate**[a] | 0.75% |
| **Construction time**[b] | 12 months |
| **Facility life**[b] | 20 years |
| **Share of Financing using traditional debt**[b] | 60% |
| **Cost of debt**[b] | 8% |
| **Cost of tax-equity**[b] | 10% |
| **Cost of direct equity**[b] | 12% |
| **Year of construction start** | 2022 |
| **Year of operation start** | 2023 |
| **Federal PTC value**[d] | 27.50 $/MWh |
| **PTC inflation**[e] | 1.8909% |
| **Insurance cost**[f] | 0.4% |
| **Decommissioning cost**[g] | $50,000/MW |

Data Sources: a: [30]. Values used from the report or calculated from data within the report.
b: [26]. c: Expert solicitation. d: [33] assuming wage and labor criteria met. e: Federal Register, 88 FR 40400, 21/06/2023. f: [34]. g: [35]. All values are in current dollars.

To describe relative construction cost differences by state requires two sets of information. USACE Civil Works Construction Cost index values [32] are used to identify relative construction costs for every state in the U.S. compared to the national average. WECC state index values are shown in Table 2. Assumed facility characteristics, interest rate and national equipment cost estimates as of 2023 necessary to compute the ACOE are described in Table 3 and come from government and industry sources. Information in Tables 2 and 3 are used to create state specific total construction and operating cost estimates.

To create estimates of cost per unit of energy produced requires estimates of the wind energy produced at an average site in each state accounting for differences in wind resources. It is assumed wind projects will only be built in the best locations for wind production in each state. GCF shown in Column A of Table 4 was estimated for the best 5 percent of land areas in each state using data from [36]. GCF does not include adjustments for reductions in output due to operational considerations such as turbine wake interference with other wind turbines, reductions for high winds or extreme temperatures that require turbines to shut down, reductions for electrical efficiency losses, and reductions for consumptive power losses necessary to maintain operation of the wind turbines. Assuming such reductions to GCF are constant across states, GCF in each state was reduced by 9.8 percent to account for equipment factors consistent with estimates found in [37], resulting in the NCF values shown in Table 4, Column B. A cumulative annual degradation factor of 0.75 percent derived from [30] was then applied to account for reduced turbine performance over time due to blade efficiency reductions and increasing maintenance needs. As shown in Table 4, Column C, this eventually reduces the capacity factor by an additional 13.3% percent over twenty years. Annual capacity factors were used to estimate energy output in each year of a facility's life.

**Table 4:** Capacity Factors Determined for each WECC State

| **State** | **Column A** Estimated GCF possible at top 5% of land | **Column B** Estimated NCF possible at top 5% of land | **Column C** NCF after 20 years using 0.75% degradation rate |
|---|---|---|---|
| **WY** | 56% | 50.5% | 43.8% |
| **NM** | 56% | 50.5% | 43.8% |
| **MT** | 56% | 50.5% | 43.8% |
| **CO** | 55% | 49.6% | 43.0% |
| **CA** | 46% | 41.5% | 36.0% |
| **OR** | 45% | 40.6% | 35.2% |
| **WA** | 45% | 40.6% | 35.2% |
| **ID** | 45% | 40.6% | 35.2% |
| **UT** | 42% | 37.9% | 32.8% |
| **AZ** | 41% | 37.0% | 32.1% |
| **NV** | 38% | 34.3% | 29.7% |

Using this information, developing the ACOE for each state occurs in four stages: defining facility construction costs, defining financing costs, defining annual operating costs and identifying tax costs. To define the facility or system cost, an identical 300 MW project is considered in each of the eleven states in the WECC by defining the cost of construction and installation costs. Installed project cost is assumed to be $1511 per kW, the average cost observed in western states in 2022 [30]. This cost is then adjusted for regional cost differences using the index values in Table 2. The computation of the total cost to construct a wind facility is also affected by sales taxes, where the majority of sales taxes over the life of a facility are paid during procurement and construction. It is assumed that two-thirds (67 percent) of system costs are taxed using rates defined in Table 1. The logic used to compute system costs is shown in Figure 6.

Once system costs are defined, financing costs to construct the facility are computed. The values assumed for the share of total system costs financed using traditional debt versus equity, the necessary rates of return payable for traditional debt, tax equity, and direct equity, and the life of the project needed to compute total finance cost estimates are summarized in Table 3. It is assumed a specific share (60 percent) of total system costs are financed by traditional debt. An amortized payment is 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 the sale of federal production tax credits the project will earn (tax equity), and the remainder is financed by direct equity. The amount of tax-equity sold is computed by calculating the production tax credits the plant is expected to create over its lifetime (plant capacity x annual state-specific capacity factor adjusted for degradation of that capacity factor over time x $27.50, the value of the tax credits as of 2023 paid per MWh of electricity produced). The net present value of these credits is then determined, discounted at the assumed tax-equity rate of return. Tax credits are assumed to be 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 the assumed required internal of return rate. The sum of financing payments on traditional debt and direct equity are then used to define the total annual finance costs of the project. The process used to compute financing costs is shown in Figure 6.

State-specific annual OPEX are computed using assumptions summarized in Table 3. The logic of this computation is also shown in Figure 6. O&M costs to run the facility over its lifetime are computed using national average annual fixed O&M costs adjusted to reflect state-specific cost differences using the values in Table 2 and estimated annually at the assumed inflation rate. Annual O&M costs are then added to the total facility annual insurance costs paid over the lifetime of the project, computed as 0.4 percent of the installed system cost. Lifetime O&M and insurance costs are then added to the costs of financing a sinking fund to cover required decommissioning costs. The assumed component costs necessary to perform this calculation are identified in Table 3, and the resulting calculation defines total OPEX costs over the life of the project.

The ACOE before taxes expressed in $/MWh is then computed by summing total annual OPEX and finance costs over the project's life and dividing that total by the expected lifetime electricity production of the facility using the assumed facility capacity, its state-specific annual capacity factor as described in Table 4.

This is the final step in Figure 6. The resulting ACOE computation is the pre-tax annual cost per MWh of output necessary to create the assumed rate of return on direct equity while covering all other costs.

The pre-tax cost methodology outlined here is similar to that used for industry estimates of levelized cost presented in [26]; however, the degree of detail in modeling costs modeled here 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 [26] ignore the impact of tax-equity financing utilizing the federal PTC.

Once pre-tax ACOE is determined for each state, property and production taxes are computed. The computations for property and production (wind) taxes are described in Figure 7. Annual property taxes are estimated for each state using the state-specific tax rules summarized in Table 1. Total taxes paid over the project's life are computed and converted to a per MWh cost. In the case of Wyoming, a production tax (referred to there as a "wind tax") is assessed per MWh of electricity produced each year using estimated electricity output derived from the project capacity, state capacity factor, and capacity factor degradation assumptions. After these taxes are computed, property and production taxes are added to the pre-tax ACOE value.

Figures 8 and 9 describe the computation of income and gross receipts taxes. To ensure the assumed rate of return payable to direct equity is achieved, 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 using the MACRS method, interest paid on traditional debt, and other tax-incentive payments. For federal taxes, up to 80 percent of any annual losses recorded are carried forward and deducted against future income, consistent with federal tax rules. Annual income taxes payable are then added to the pre-tax system costs to determine a new ACOE. 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 convergence to a constant payment. All computations are made using Microsoft Excel using the Solver Add-in. Spreadsheet estimates and detailed methodology of all cost computations are available upon request. Cost estimates presented overlook time of day or seasonal generation profiles that could affect the relative value of generation across states or locations.

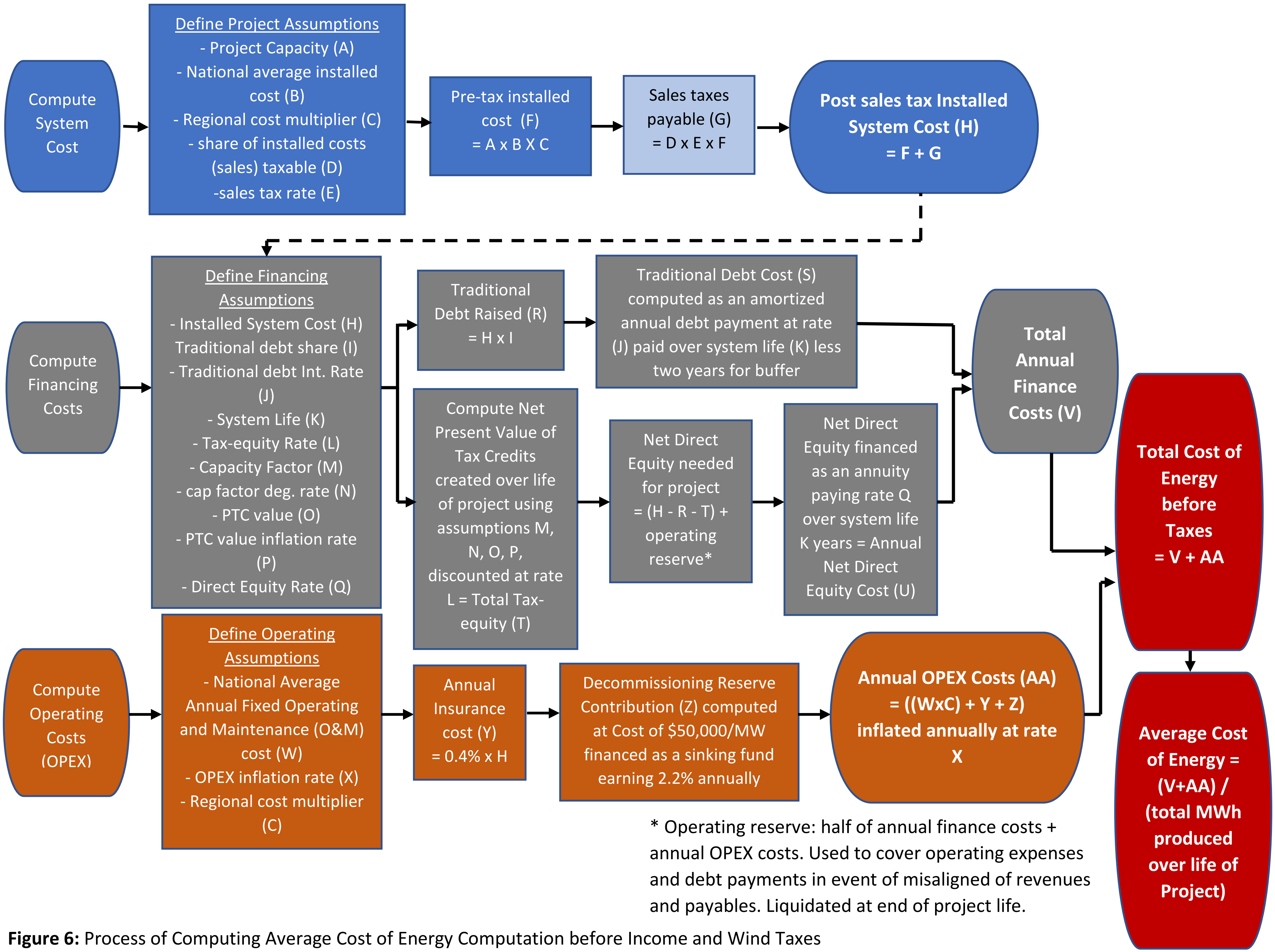


**Figure 6:** Process of Computing Average Cost of Energy Computation before Income and Wind Taxes

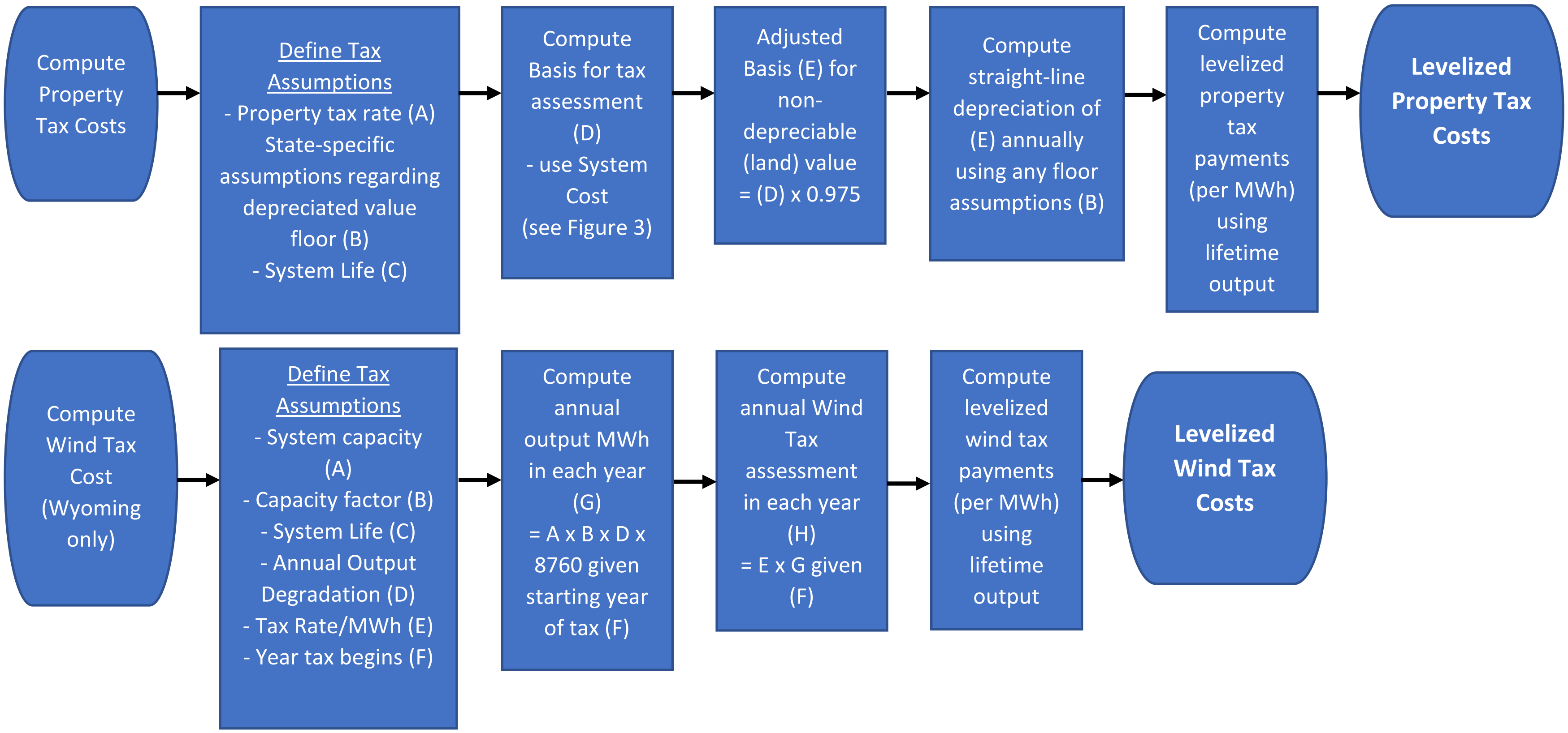


**Figure 7:** Property and Wind Tax Cost Computation Processes

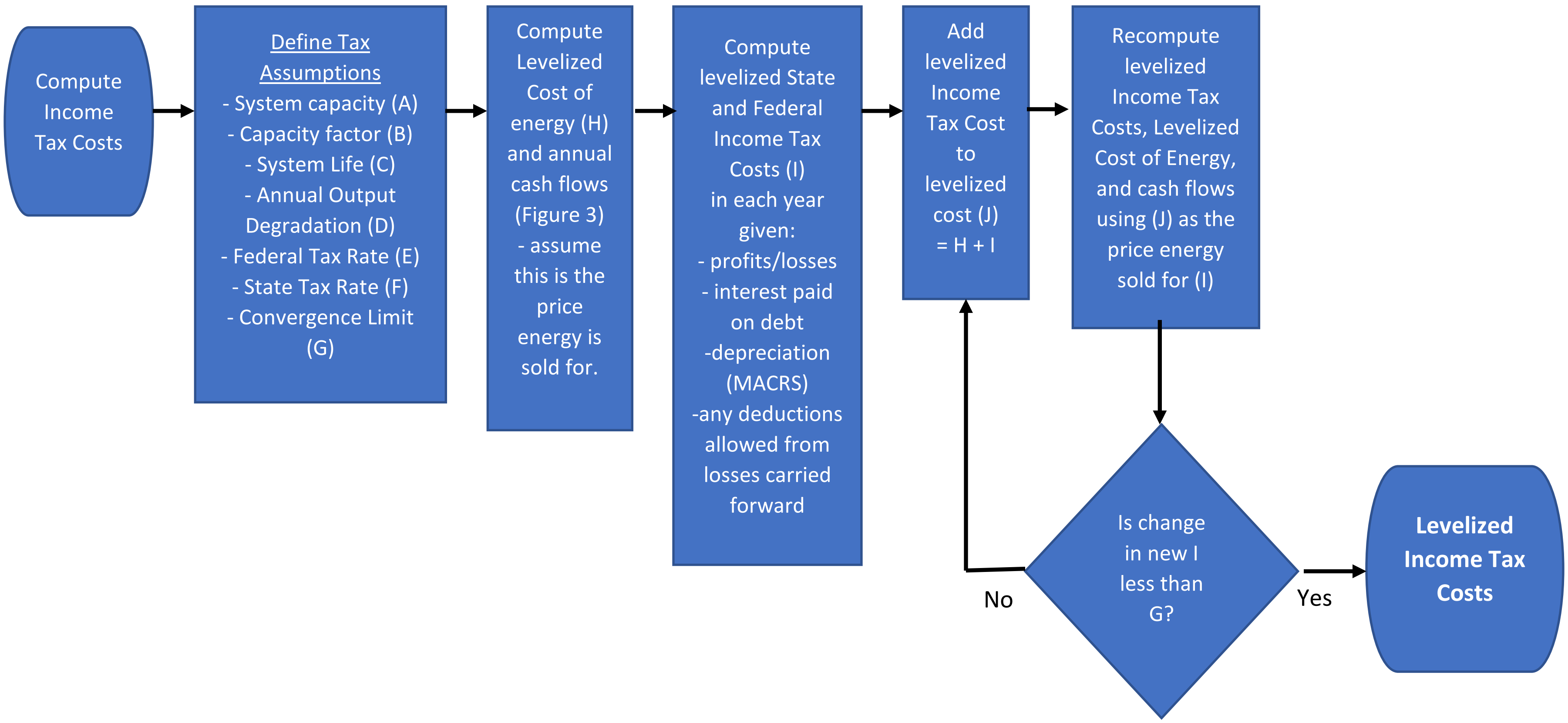


**Figure 8:** Income Tax Cost (Federal and State) Computation

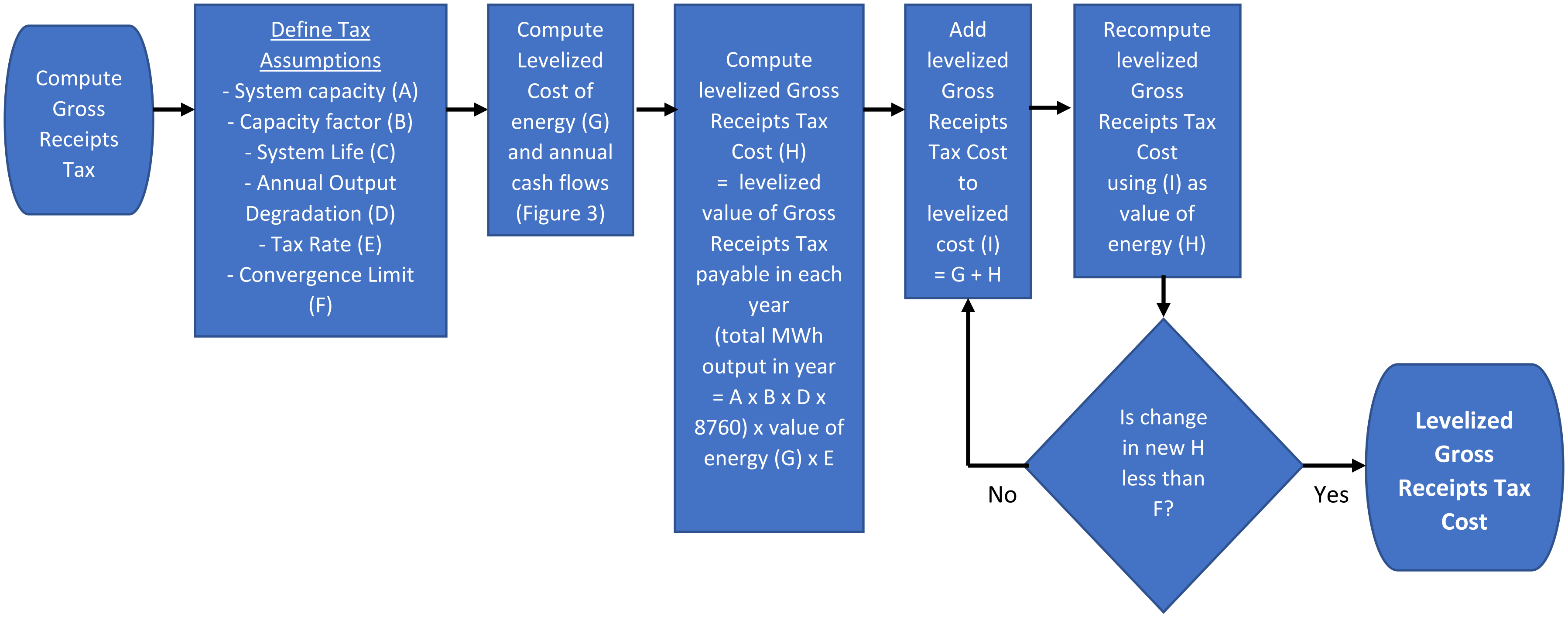


**Figure 9:** Gross Receipts Tax Cost Computation

While the ACOE estimates developed here are specific to the WECC region of the U.S., the same methods could be applied to any region. To develop such cost estimates requires several types of data. First the characteristics of the project to be constructed must be identified – the generation capacity and type of technology assumed to be used at the facility, and the construction time of the project. Then cost estimates have to be identified for the equipment, installation and construction, including how such costs differ by state. A limitation of such modeling is the need for such very specific data, which may not be easily identified. The deterministic nature of the cost methodology proposed here implies results will be very dependent upon the accuracy of any data estimates needed. Where such data is not available, a useful first step for policymakers may be an effort to create such data and distributing it publicly in a format like that found in [30]. The relative cost results among states are especially dependent on state-specific wind resource estimates, construction and installation cost differences. Lack of availability of such data would also be a challenge for policymakers considering using ACOE estimates like those presented here as they are necessary to compute differences in relative state ACOE values. Without such data, however, ACOE estimates can still be made for the cost of development within a state and therefore are useful in understanding how within-state costs are affected by state incentives. Financing assumptions must also be identified to compute ACOE estimates, specifically how such projects are typically financed and the cost of borrowing for each type of financing used. This may require consultation with industry to understand specific practices used by developers. Estimates here are consistent with how projects in the United States are financed.

Since the ACOE computed for each state results when total costs are divided by potential output, ACOE will be inversely proportional to state-specific capacity factor. There is little difference in either observed capacity factors or estimated potential capacity factors between the top four states in Table 4 (New Mexico, Wyoming, Montana, and Colorado) and this suggests that other aspects affecting cost could have significant influence for any developer making a location decision in one of the four states, specifically state-specific construction costs and incentives. for states with similar wind resources and construction costs, ACOE results could be very useful to policymakers when considering state incentives and their potential impact on a state's cost-competitiveness and its ability to attract development. Note that the estimates developed here do not include any additional costs necessary to complete local permitting or transmission development that may also affect such decisions. Such considerations could also be included in the computation if data were available and are also likely to affect developers' location decisions for development. Consideration of such costs could also be an important policy consideration.

## 5. Results: Estimated State Tax Policy Impacts

Using the methodology, cost, and state policy assumptions described previously, ACOE estimates for WECC states are presented in Figure 10. ACOE values are presented as a range for each state bracketed by values under two different sets of assumptions. Values for each state's ACOE are presented ignoring differences in cost due to regional construction cost (index values for regional cost are set equal to 1.0) and wind resources (by assuming identical 35 percent capacity factors in each state). Under these conditions, the only causes of cost variation by state are the differences in incentives and taxes. This computation typically defines the high end of the range of ACOE for each state. Nevada and California are the exceptions where they represent low-end cost estimates for different reasons. For Nevada, the NCF at the top 5 percent of the land is less than 35 percent (Table 5, Column B) thus using a 35 percent capacity factor results in the lowest cost estimate for this state. For California, though the state-specific capacity factor of 41.3 percent (Table 5, Column B) is greater than 35 percent, because the state-specific California's construction cost is so much higher than the other WECC states, as shown in Table 2, the lowest ACOE estimate for this state is defined when state-specific cost factors are ignored. At the other end of each state range presented in Figure 10 are the state ACOE estimates computed when state-specific capacity factors and regional construction cost differences are considered along with state-specific incentive and tax policies.

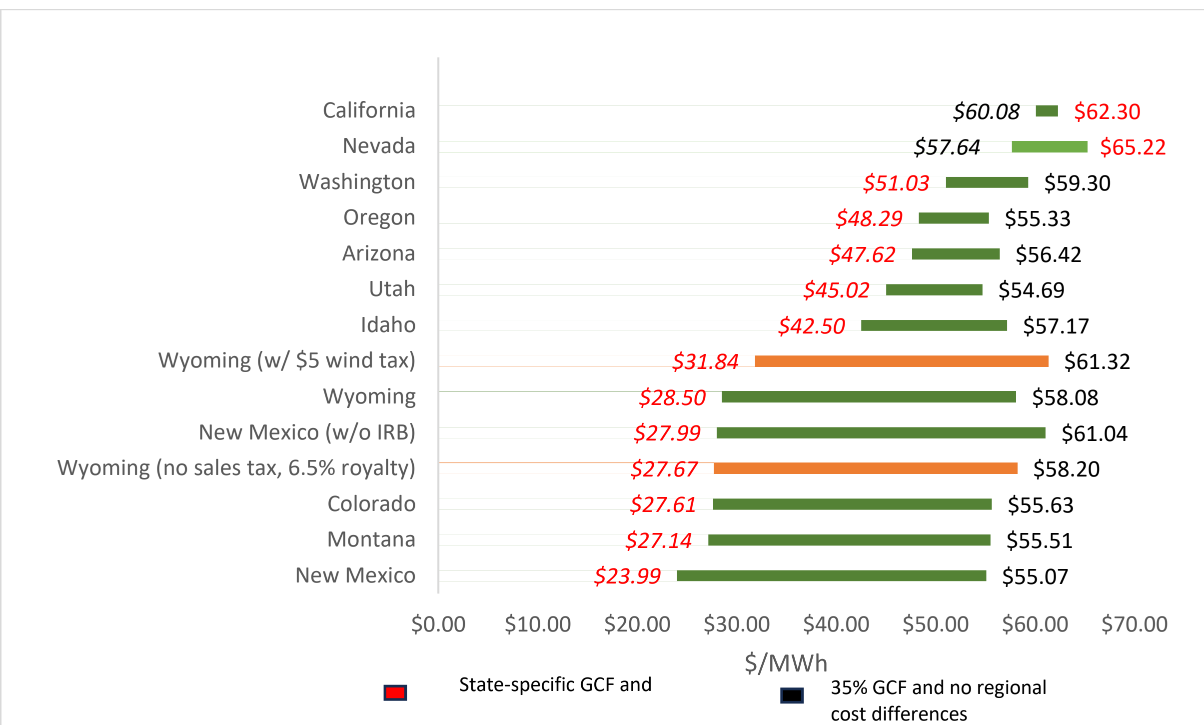


**Figure 10:** State Estimates of Wind Generation Average Cost of Energy with Current Taxes/Incentives

Two states in Figure 10 have multiple entries. The estimated range of ACOE for Wyoming is shown for current tax and incentive policies, and for two alternative tax policies: one that considers a $5 per MWh wind generation tax considered by the state legislature between 2016 and 2020, and one that considers a sales tax and royalty change. Both are shown in an alternative colour to indicate they are not current policy. New Mexico appears twice in the chart as, under current state policy, projects may or may not take advantage of IRBs and associated PILOT payments at negotiated rates. IRB's have been used for all wind projects in New Mexico over the past decade, but the non-IRB alternative is shown for completeness. Comparing states, the lowest ACOE occurs for New Mexico when IRBs are used. The next three lowest-cost states are estimated to be Montana, Colorado, and Wyoming, with only a 4 percent difference between Montana and Wyoming when current taxes and incentives are considered. The next lowest state is Idaho, where costs are almost 50 percent higher than Wyoming, and ACOE estimates of the remaining states are even higher.

Cost estimates presented verify an inference suggested previously from patterns of more recent and proposed development - the importance of resource quality. The four lowest-cost states represent the four states with the highest capacity factors as defined in Table 4. New insights are also suggested. Previous literature has not considered regional labor and construction costs as an important determinant of location decisions. The four lowest-cost states also have the lowest regional cost index values in the region, varying from 0.94 to 0.90, as shown in Table 2. These two factors – resource quality and comparative construction costs – therefore drive the cost results in New Mexico, Montana, Colorado and Wyoming, which have the lowest estimated development costs when all factors are considered. Overall, cost results make a compelling argument for understanding development patterns over the past decade in Figure 2, and patterns of future development shown in Figure 3.

Results also suggest how certain tax and incentive differences across these states can determine a state's cost competitiveness. Tables 5 and 6 detail the decomposition of overall ACOE estimates by state when wind resources and regional costs are considered and when capacity factor and regional costs are held constant, respectively. Figure 11 summarizes these state tax burden outcomes. When ranked considering potential resource and construction cost differences, Colorado has the lowest tax burden after incentives of any state. Utah and Arizona rank second and fourth, respectively, reflecting the higher value of incentives in these states. Montana ranks third, primarily due to incentives and the lack of a sales tax, while Oregon ranks fifth due to the low taxes and moderate incentives.

Following these states are New Mexico and Wyoming, which are instructive for different reasons. Both assume identical wind resources as defined by capacity factors on the top 5% of land, while New Mexico has regional construction costs estimated to be 3.2 percent lower than Wyoming's. New Mexico's tax burden is $0.58 less than Wyoming's but its estimated ACOE is $4.51 (15.8 percent) less. Results demonstrate that New Mexico's primary incentive is not a direct tax incentive policy, but rather the ability to use bonding to reduce developers' financing costs. The importance of this incentive on comparative costs is clear in Figure 10 when New Mexico's computed ACOE without IRBs is considered. If IRBs were not used the state would fall below Colorado and Montana in the cost rankings. These results suggest the potential of an incentive not previously considered in the literature: IRB programs. As shown, they can have a powerful influence on developer's costs.

From the various forms of taxation across states in the WECC, a logical question arises as to which forms of taxation lead to the least tradeoff between economic development and revenue. 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 concerning development is generally inconsistent [38].

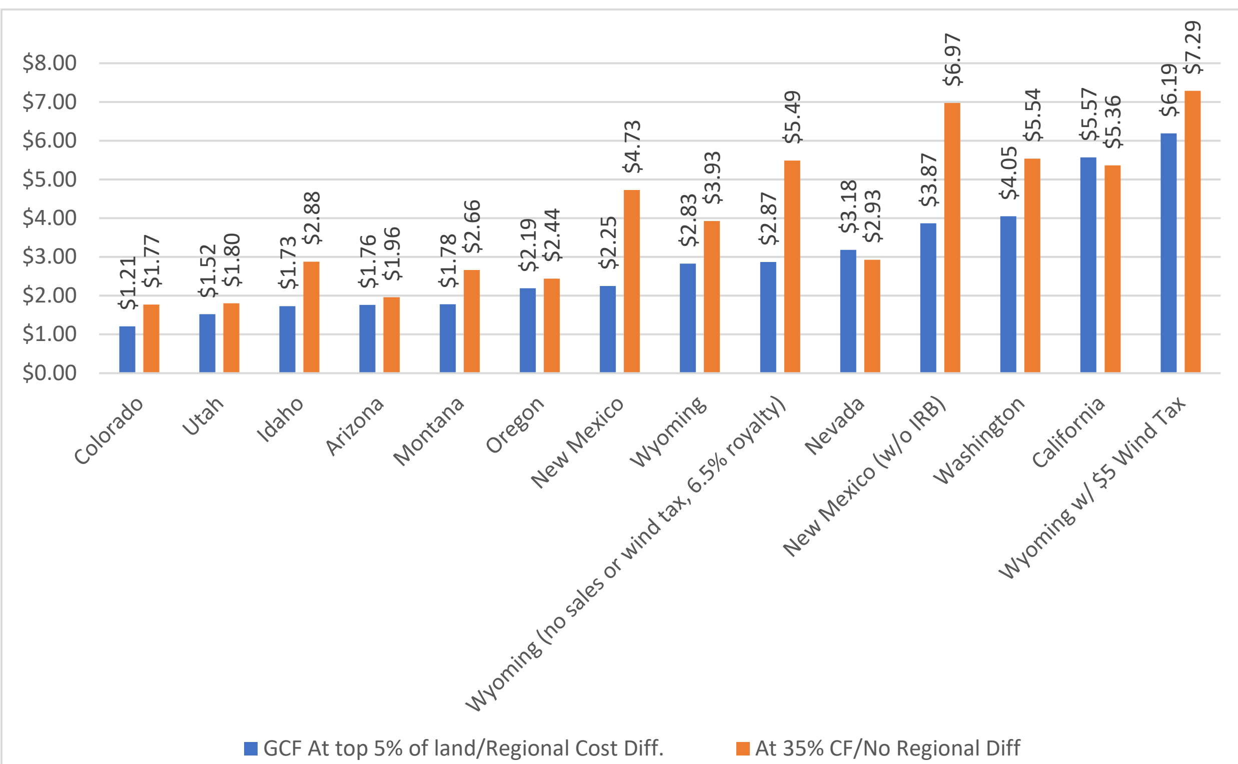


**Figure 11:** Comparative State Tax Burdens on Wind Development by State

As shown in Tables 5 and 6, 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. While lower income taxes are often assumed an economic development advantage for some states [38], this is actually an inaccurate generalization and depends on the industry considered. In capital-intensive ones like wind generation, the income tax burden of such facilities is comparatively small relative to other taxes due to high interest and depreciation costs that can be deducted, lowering or eliminating such tax liabilities. Therefore, states like Nevada, Washington, and Wyoming in the WECC see little advantage in attracting wind development by having no income taxes. This conclusion is consistent with general studies of corporate income and business tax impacts on economic development, where little negative impact of such taxes is identified [38].

While Nevada and Washington have no income tax, they, New Mexico, and Idaho do assess a gross receipts tax. 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. While such a tax can increase revenues for wind development over an income tax, as is apparent in Tables 5 and 6, it also increases the cost of wind generation, potentially deterring such development.

As noted previously, sales taxes are primarily paid during procurement and construction, which are assumed to be financed, and therefore affect the after-tax system costs of a project directly and through additional finance costs. Given these impacts, the benefit of sales tax reductions on wind development may be larger than exemptions on other taxes, specifically property taxes, the most common form of taxation on wind across WECC states. Explicitly modeling sales tax effects and separating them from other taxation effects may explain why property tax incentive effects were more difficult to identify than sales tax effects in previous literature. Results in Tables 5 and 6, however, do not allow for any generalizations regarding whether sales or property taxes are more important to developers' costs. What matters most is the total cost from a developer's perspective, and how relative costs change across states for any given change in tax policy. This may explain the results of previous econometric literature where the suggested importance of different taxes often varied by study.

**Table 5:** 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 ($5 Wind Tax) | Wyoming (6.5% Royalty, No Sales or Wind Tax) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **System & Federal Taxes** | | | | | | | | | | | | | | |
| System Cost | $23.77 | $27.43 | $17.35 | $22.11 | $17.22 | $29.16 | $16.49 | $16.49 | $24.39 | $23.45 | $24.39 | $17.04 | $17.04 | $17.04 |
| Federal Tax Credits | -$9.45 | -$9.45 | -$9.45 | -$9.45 | -$9.45 | -$9.45 | -$9.45 | -$9.45 | -$9.45 | -$9.45 | -$9.45 | -$9.45 | -$9.45 | -$9.45 |
| Financing Cost | $14.06 | $18.98 | $5.62 | $11.87 | $4.89 | $21.10 | $2.39 | $4.81 | $13.54 | $12.40 | $14.34 | $5.43 | $5.43 | $4.67 |
| Operating Costs | $17.48 | $19.78 | $12.75 | $16.22 | $12.58 | $21.23 | $12.13 | $12.18 | $17.62 | $17.10 | $17.70 | $12.54 | $12.54 | $12.46 |
| Federal Income Taxes | $0.01 | $0.00 | $0.14 | $0.02 | $0.12 | $0.00 | $0.18 | $0.10 | $0.00 | $0.01 | $0.00 | $0.11 | $0.09 | $0.08 |
| **Pre-State Tax Total** | **$45.86** | **$56.74** | **$26.40** | **$40.76** | **$25.36** | **$62.04** | **$21.74** | **$24.12** | **$46.10** | **$43.50** | **$46.98** | **$25.66** | **$25.65** | **$24.80** |
| **State Taxes Before Incentive** | | | | | | | | | | | | | | |
| Sales Taxes (financed) | $1.05 | $1.47 | $0.47 | $0.89 | $0.00 | $1.51 | $0.66 | $0.66 | $0.00 | $0.76 | $1.32 | $0.63 | $0.63 | $0.00 |
| Property Taxes | $2.86 | $4.10 | $3.73 | $0.00 | $2.80 | $3.64 | $1.69 | $1.73 | $2.74 | $2.26 | $2.45 | $1.36 | $1.36 | $1.31 |
| State Income Tax | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| Gross Receipt Taxes | $0.00 | $0.00 | $0.00 | $0.84 | $0.00 | $0.03 | $1.48 | $1.48 | $0.00 | $0.00 | $0.94 | $0.00 | $0.00 | $1.56 |
| Excise Taxes | $0.00 | $0.00 | $0.00 | $0.00 | $0.15 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.84 | $4.20 | $0.00 |
| **State Taxes w/o Incentives** | **$3.91** | **$5.57** | **$4.20** | **$1.73** | **$2.95** | **$5.18** | **$3.83** | **$3.87** | **$2.74** | **$3.02** | **$4.71** | **$2.83** | **$6.19** | **$2.87** |
| **State Taxes After Incentives** | | | | | | | | | | | | | | |
| Sales Taxes | $1.05 | $1.47 | $0.47 | $0.89 | $0.00 | $1.51 | $0.27 | $0.66 | $0.00 | $0.00 | $0.66 | $0.63 | $0.63 | $0.00 |
| Property Taxes | $0.72 | $4.10 | $0.74 | $0.00 | $1.63 | $1.64 | $0.51 | $1.73 | $2.19 | $2.26 | $2.45 | $1.36 | $1.36 | $1.31 |
| Income Taxes | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | -$0.74 | $0.00 | $0.00 | $0.00 | $0.00 |
| Gross Receipt Taxes | $0.00 | $0.00 | $0.00 | $0.84 | $0.00 | $0.03 | $1.48 | $1.48 | $0.00 | $0.00 | $0.94 | $0.00 | $0.00 | $1.87 |
| Excise Taxes | $0.00 | $0.00 | $0.00 | $0.00 | $0.15 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.84 | $4.20 | $0.00 |
| **State Taxes w/ Incentives** | **$1.76** | **$5.57** | **$1.21** | **$1.73** | **$1.78** | **$3.18** | **$2.25** | **$3.87** | **$2.19** | **$1.52** | **$4.05** | **$2.83** | **$6.19** | **$2.87** |
| Reduction in State Taxes due to Incentives | $2.15 | $0.00 | $2.99 | $0.00 | $1.16 | $2.00 | $1.57 | $0.00 | $0.55 | $1.50 | $0.66 | $0.00 | $0.00 | $0.00 |
| % Reduction in State Taxes due to Incentives | 54.9% | 0.0% | 71.1% | 0.0% | 39.5% | 38.6% | 41.2% | 0.0% | 20.0% | 49.8% | 14.1% | 0.0% | 0.0% | 0.0% |
| **Average Cost of Electricity (ACOE) $/MWh** | **$47.62** | **$62.30** | **$27.61** | **$42.50** | **$27.14** | **$65.22** | **$23.99** | **$27.99** | **$48.29** | **$45.02** | **$51.03** | **$28.50** | **$31.84** | **$27.67** |
| 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% | 50.5% |
| Assumed Regional Cost Difference | 0.95 | 1.23 | 0.93 | 0.97 | 0.94 | 1.08 | 0.90 | 0.90 | 1.07 | 0.96 | 1.07 | 0.93 | 0.93 | 0.93 |

Column totals and subtotals may not sum exactly due to rounding.

**Table 6:** 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 ($5 Wind Tax) | Wyoming (6.5% Royalty, No Sales or Wind Tax) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **System & Federal Taxes** | | | | | | | | | | | | | | |
| System Cost | $26.43 | $26.43 | $26.43 | $26.43 | $26.43 | $26.43 | $26.43 | $26.43 | $26.43 | $26.43 | $26.43 | $26.43 | $26.43 | $26.43 |
| Federal Tax Credits | -$9.45 | -$9.45 | -$9.45 | -$9.45 | -$9.45 | -$9.45 | -$9.45 | -$9.45 | -$9.45 | -$9.45 | -$9.45 | -$9.45 | -$9.45 | -$9.45 |
| Financing Cost | $17.40 | $17.70 | $16.86 | $17.28 | $15.99 | $17.64 | $13.40 | $17.27 | $15.99 | $15.99 | $16.86 | $17.17 | $17.17 | $15.99 |
| Operating Costs | $19.34 | $19.38 | $19.29 | $19.33 | $19.20 | $19.37 | $19.25 | $19.33 | $19.20 | $19.20 | $19.29 | $19.32 | $19.32 | $19.20 |
| Federal Income Taxes | $0.74 | $0.67 | $0.73 | $0.70 | $0.69 | $0.72 | $0.71 | $0.50 | $0.72 | $0.72 | $0.64 | $0.68 | $0.57 | $0.54 |
| **Pre-State Tax Total** | **$54.46** | **$54.72** | **$53.86** | **$54.29** | **$52.86** | **$54.71** | **$50.34** | **$54.07** | **$52.89** | **$52.89** | **$53.76** | **$54.15** | **$54.03** | **$52.71** |
| **State Taxes Before Incentive** | | | | | | | | | | | | | | |
| Sales Taxes (financed) | $1.17 | $1.42 | $0.72 | $1.06 | $0.00 | $1.37 | $1.05 | $1.05 | $0.00 | $0.86 | $1.43 | $0.97 | $0.97 | $0.00 |
| Property Taxes | $3.18 | $3.95 | $5.68 | $0.00 | $4.29 | $3.30 | $2.71 | $2.78 | $2.96 | $2.55 | $2.65 | $2.11 | $2.11 | $2.04 |
| State Income Tax | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.15 | $0.00 | $0.07 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| Gross Receipt Taxes | $0.00 | $0.00 | $0.00 | $1.82 | $0.00 | $0.08 | $3.33 | $3.14 | $0.00 | $0.00 | $2.17 | $0.00 | $0.00 | $3.45 |
| Excise Taxes | $0.00 | $0.00 | $0.00 | $0.00 | $0.15 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.84 | $4.20 | $0.00 |
| **State Taxes w/o Incentives** | **$4.35** | **$5.36** | **$6.41** | **$2.88** | **$4.44** | **$4.74** | **$7.25** | **$6.97** | **$3.04** | **$3.40** | **$6.26** | **$3.93** | **$7.29** | **$5.49** |
| **State Taxes After Incentives** | | | | | | | | | | | | | | |
| Sales Taxes | $1.17 | $1.42 | $0.72 | $1.06 | $0.00 | $1.37 | $0.43 | $1.05 | $0.00 | $0.00 | $0.72 | $0.97 | $0.97 | $0.00 |
| Property Taxes | $0.80 | $3.95 | $1.05 | $0.00 | $2.51 | $1.48 | $0.81 | $2.78 | $2.37 | $2.55 | $2.65 | $2.11 | $2.11 | $2.04 |
| Income Taxes | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.15 | $0.00 | $0.07 | -$0.74 | $0.00 | $0.00 | $0.00 | $0.00 |
| Gross Receipt Taxes | $0.00 | $0.00 | $0.00 | $1.82 | $0.00 | $0.08 | $3.33 | $3.14 | $0.00 | $0.00 | $2.17 | $0.00 | $0.00 | $3.45 |
| Excise Taxes | $0.00 | $0.00 | $0.00 | $0.00 | $0.15 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.84 | $4.20 | $0.00 |
| **State Taxes w/ Incentives** | **$1.96** | **$5.36** | **$1.77** | **$2.88** | **$2.66** | **$2.93** | **$4.73** | **$6.97** | **$2.44** | **$1.80** | **$5.54** | **$3.93** | **$7.29** | **$5.49** |
| Reduction in State Taxes due to Incentives | $2.39 | $0.00 | $4.63 | $0.00 | $1.79 | $1.81 | $2.52 | $0.00 | $0.59 | $1.60 | $0.72 | $0.00 | $0.00 | $0.00 |
| % Reduction in State Taxes due to Incentives | 54.9% | 0.0% | 72.3% | 0.0% | 40.2% | 38.3% | 34.8% | 0.0% | 19.5% | 47.0% | 11.5% | 0.0% | 0.0% | 0.0% |
| **Average Cost of Electricity (ACOE) $/MWh** | **$56.42** | **$60.08** | **$55.63** | **$57.17** | **$55.51** | **$57.64** | **$55.07** | **$61.04** | **$55.33** | **$54.69** | **$59.30** | **$58.08** | **$61.32** | **$58.20.** |
| Assumed Capacity Factor | 35% | 35% | 35% | 35% | 35% | 35% | 35% | 35% | 35% | 35% | 35% | 35% | 35% | 35% |
| 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 | 1.00 |

Column totals and subtotals may not sum exactly due to rounding.

Production incentives (subsidies) or production taxes have previously been found to be a powerful incentive to encourage wind development [23]. Wyoming has considered increasing its production tax on wind from $1 per MWh to as high as $5 per MWh (see [11]). In the WECC area, production subsidies are not offered by states, and Wyoming is unique in using a wind production tax to raise revenue, charging $1 per MWh of production under current policy. ACOE results suggest increasing the state's wind production tax to $5 per MWh would have a significant impact on development costs in Wyoming. The impact of such a tax increase on Wyoming's relative cost-competitiveness can be seen in Tables 5 and 6, as well as Figures 10 and 11. While the state's overall cost ranking, as shown in Figure 10 would remain fourth lowest in the WECC when state-specific potential capacity factors and cost differences are considered, Wyoming's ACOE would rise by 11.7 percent and results in Figure 10 show this would more than double the state's overall tax burden. The ACOE in Wyoming with the increased tax would rise to almost 33 percent more than New Mexico's (when IRBs are used) and over 17 percent higher than Montana's and 15 percent higher than Colorado's.

Such a cost increase may be expected to have an observable effect on wind development in the state as it decreases the state's cost-competitiveness significantly. Tables 5 and 6 more clearly demonstrate the impact of such a tax increase. The cost of the wind excise tax now increases from $0.84 per MWh to $4.20 and more than doubles the total tax burden per MWh of wind-generated electricity in Wyoming as shown in Figure 10, reducing its competitiveness significantly with other low-cost states in the region. Overall, such a change in costs could be expected to potentially incentivize reconsideration of currently planned development and possible relocation to other more affordable states. When the tax increase was considered in the Wyoming legislature, developers of the ChokeCherry project indicated such an increase would lead to reconsideration or cancellation of the project. The foregone economic impacts of such a change would have been significant, as described in [11]. ACOE results developed here could have been informative to policymakers when the change was considered, as there was little information regarding how the proposal would have changed developers' costs or the state's relative cost-competitiveness.

Given these results, states looking to increase tax revenues from wind development should consider production taxes very carefully, taking into consideration the relative costs already present for wind producers, and how changes in taxation or incentives may impact those relative costs if they wish to attract development or raise revenue. It is not necessarily the type of tax that matters as the impact on overall development cost. Managing the tradeoff between tax revenue and development impact requires consideration of how specific taxes affect total relative costs among states for developers. This is where cost-modeling could be most useful in policy – in allowing design of tax systems that minimize cost impacts and revenues, using the model as a laboratory to experiment with various tax designs before implementation to determine their potential impacts on a state's attractiveness for development.

### 5.1 Using a Cost Model to Improve Tax Revenues and Cost-Competitiveness in Wyoming: A Case Study

Wyoming is an instructive example of how modeling local state incentive and tax impacts on ACOE could be useful in designing state policies that improve cost-competitiveness to attract wind development while protecting fiscal revenue. Given the on-going energy transition, protecting fiscal revenue may be an important consideration, especially for fossil producing states. As [39] estimate, four states (Wyoming, New Mexico, Montana, and Colorado) in the WECC rank among the top fossil-fuel revenue-dependent states nationally and may be most fiscally impacted by the ongoing energy transition. Of the four, Wyoming's dependence is the highest in the country at 54 percent. For this reason, states like Wyoming may face a tradeoff, wishing to raise revenues from wind to offset losses elsewhere, but also recognizing that doing so could reduce a state's competitiveness to attract new activity in the state to offset that lost by the decline in fossil fuel production. The previously shown example describing how an increased wind tax affects developers' costs demonstrates this potential tradeoff.

To protect tax revenues from wind, in 2009, Wyoming repealed its sales tax exemption on wind equipment. The resulting cost impact of this action on new wind development is estimated to be $0.63 per MWh, as shown in Table 5. This does not include the financing cost required to pay these taxes during construction and before operations begin. Wyoming also implemented its wind production tax of $1/MWh in 2011, which is imposed after a project has operated for three years. This increases ACOE by $0.84 per MWh over the life of the project. Over half of Wyoming's tax revenues per MWh rely on production and sales taxes, which have been argued in some previous research to have larger negative impacts on economic development [23]. When existing property taxes are considered, the total cost of taxes for new wind development in Wyoming is $2.83 per MWh. After these tax changes were implemented, wind development in the state, which had been booming, stopped and only one 80 MW facility was built during the following eight years, as shown in Figure 2. Construction did not slow in Colorado or New Mexico during this time, and therefore the sudden reduction in wind development in Wyoming may be attributable, at least in part, to this tax change.

Consider how the tradeoff between tax revenues and developer costs might have been managed differently. Specifically, as an alternative tax policy experiment, consider how the state's estimated ACOE would be affected if the state's sales tax exemption were reinstated on wind equipment, and the current

$1 per MWh production tax was rescinded. To replace the lost revenue from these changes, suppose a royalty on the value of electricity produced was assessed, an idea Wyoming also considered in 2009 ([40] and [41]). Assume the royalty rate was set at 6.5 percent, consistent with the level Wyoming charges as a royalty on surface coal mining in the state.

**Table 7:** Wyoming ACOE Composition Under Alternative Tax Scenario and Current Tax Policy.

| | **Results Assuming 6.5% Royalty, Sales Tax Exemption, No Production Tax, Current Property Taxes.** | | **Results under Current Wyoming Tax Policy** | |
|---|---|---|---|---|
| | **Total Cost** | **Total Cost per MWh** | **Total Cost** | **Total Cost per MWh** |
| **System & Federal Taxes** | | | | |
| **System Cost** | $421,569,000 | $17.04 | $421,569,000 | $17.04 |
| **Federal Tax Credits** | ($233,932,524) | ($9.45) | ($233,932,524) | ($9.45) |
| **Financing Cost** | $115,615,580 | $4.67 | $134,394,748 | $5.43 |
| **Operating Costs** | $308,335,693 | $12.46 | $310,236,355 | $12.54 |
| **Federal Income Taxes** | $2,072,934 | $0.08 | $2,753,348 | $0.11 |
| **Pre-State Tax Total** | **$613,660,683** | **$24.80** | **$635,020,927** | **$25.67** |
| **State Taxes After Incentives** | | | | |
| **Sales Taxes** | $0 | $0.00 | $15,534,818 | $0.63 |
| **Property Taxes** | $32,509,646 | $1.31 | $33,707,627 | $1.36 |
| **Income Taxes** | $0 | $0.00 | $0 | $0.00 |
| **Royalties** | $38,647,154 | $1.56 | $0 | $0.00 |
| **Excise Taxes** | $0 | $0.00 | $20,791,646 | $0.84 |
| **State Taxes w/ Incentives** | **$71,156,800** | **$2.87** | **$70,034,091** | **$2.83** |
| **Total Cost of Electricity/ACOE** | **$684,817,483** | **27.67** | **$705,055,018** | **$28.50** |
| **Megawatt Hours Produced (20 years)** | | 24,742,845 | | 24,742,845 |

Results in Table 7 suggest that with these changes, Wyoming could increase state competitiveness to attract wind development by lowering ACOE while increasing total revenues from wind facility taxation. The elimination of sales and production taxes paid over the project's life and replacing them with a royalty fee of 6.5 percent assessed on the revenues created from electricity sales would reduce the ACOE of wind development in Wyoming from $28.50 to $27.67, a reduction of 2.9 percent. The tax change reduces the total cost of electricity over the project's life by over $20.2 million or, on average, over $1 million per year. Wyoming's ACOE would fall to a level nearly equal to Colorado's among WECC states. Given previous findings on the drivers of wind development, this change would potentially improve the state's attractiveness to developers. From the cost modeling exercise, we can see this would occur because of the reduction in financing costs this creates as sales taxes payable no longer require financing, while changes in the taxes paid on generation as production taxes from generation would be replaced by royalties. When taxes collected per megawatt hour in Wyoming are considered as shown in Figure 11, the total taxes collected rise by over $1.1 million over the project's life, and on a per MWh basis, increasing from $2.83 to $2.87 per MWh, or nearly 1.5 percent. Relative ACOE competitiveness improves because the reduced sales tax burden lowers financing costs by 14 percent. Federal income tax and operating costs are also reduced by 24.7 percent and 3.4 percent, respectively.

While undiscounted total tax revenues over the project's life are greater under the proposed tax scheme, consideration should also be given to the impact of alternative tax policies on the stream of tax revenues a state receives. The annual payments created by a royalty would create a reliable income stream for the state and communities affected, lasting the life of the project. Conversely, a sales tax like that currently levied in Wyoming results in a very large short-term windfall that requires management and can be problematic due to its one-time nature. Often it may be preferable for one-time revenues to be spent over time. In some cases, however, local governments have budgetary rules that make banking unspent sales tax revenues for use later difficult, and even when such banking is possible, this tax structure can result in very real political consequences. For example, a municipal leader banking unspent revenues invites political challenges from anti-tax opponents who may argue for a lower-tax platform based on the premise that such savings prove that taxes are higher than necessary. In preliminary research for this work, public leaders were consulted regarding preferences over public revenues and several admitted they value streams of payments over much larger one-time lump sum payments because they make sustainable budgeting easier to plan.

## 6. Conclusions

Wind generation is a significant potential source of development and economic diversification in the rural western United States, especially given newly offered federal clean energy incentives. Since state policy can affect the cost of wind development, states and communities should be cognizant of how tax and incentive policy changes can impact their relative development costs with those of other states. To address policymakers' needs to understand the potential impacts of any tax or incentive decisions.

This study explores the potential benefits of using a detailed cost model describing the financial structure of typical utility-scale wind development to determine how changes in local and state taxation and incentive policies affect developers' costs across states in the WECC region of the U.S. The methods and results presented here can inform policymakers of relative development cost conditions across states and may help identify where tax changes can better achieve state goals. Methods developed here can also be adapted to areas outside the United States by applying relevant local assumptions, as wind development often represents an opportunity for many rural areas worldwide. Where such regions are also fossil-fuel producing areas, wind and renewable development can create opportunities for alternative economic activity to offset the effects of energy transitions away from traditional fuels. Wind and renewable development can also create important new fiscal revenues for communities.

Using a detailed model describing the cost structure of a utility-scale wind development, it is argued that considering a wind development's capital structure is crucial to understanding how different taxation and other policies affect wind development location choices. It can also resolve some contradictions and ambiguities in previous econometric efforts that attempted to determine the impacts of state tax and incentive policies on wind development outcomes. The analysis presented here estimates the impact of local state taxation and incentive policies on the cost of developing wind across the western United States. Cost estimates derived are consistent with current development patterns in these states, and results are consistent with the argument that comparative development costs across states are important drivers of developers' location choices.

Understanding how policy changes could affect the cost of wind development relative to other states is essential to avoid unintended development impacts. Taxation and incentive program changes could have significant effects on developers' costs and location choices. Economic development tradeoffs may also exist when policy incentives used to attract wind development lead to foregone fiscal revenues, as is commonly the case with tax incentives. A benefit of specifically modeling developers' costs is the ability to consider holistically how different taxation and incentive choices, or combinations of such changes may impact the cost-competitiveness of states and regions competing for wind projects as a form of economic development, while also considering tax revenue implications.

Some tax incentives affect wind development not only by their direct effect on project tax burdens but also by their impact on other costs, such as financing. Given this, it is important to consider the capital, operating, and tax structure of wind developments together to understand how tax policies and incentive changes may impact project costs and a state's attractiveness for wind development. Such considerations also suggest alternative or non-tax incentives that may be promising avenue to attract wind development. This study has identified IRBs as one such example of lesser-used incentives that could be considered to attract greater investment in regions desiring wind energy development. There is little research regarding such incentives and their impact on renewable energy development, and considering such programs could be a fruitful area for future research efforts. Wider use of such incentives may not only improve states' ability to attract wind development, but they could also increase the development of renewables and aid policymakers in achieving sustainable development targets more quickly.

The modeling presented also allows an additional insight for policymakers. Cost competitiveness need not occur as a tradeoff with state revenues. Careful design of state tax policies, including altering the composition of taxes, combined with offering other creative policies such as alternative financing in the form of IRBs or similar, may lower the cost of wind development, incentivizing greater economic development and allow other opportunities to simultaneously increase revenues. Such opportunities could be particularly appealing to states competing to attract development while facing revenue declines from fossil fuels in the ongoing energy transition. These ideas are demonstrated through consideration of tax policies in New Mexico and Wyoming as examples. As shown in the case of Wyoming, it may be possible to identify a policy that limits or even avoids such tradeoffs using a cost model as a means of testbedding the potential effects of a policy change before implementation, and as a means of optimizing combinations of policy incentives and tax choices.

Use of such cost modeling is not without challenges. It requires forms of expertise that may not be readily available to policymakers, specifically the development of financial models that describe how large renewable energy projects are financed. Such models also require specific data that may not be easily accessed regarding specific equipment costs, relative construction cost differences across regions, specific knowledge of state and local tax structures and how they affect development costs, and wind resource data. As this study demonstrates, such data can be identified, and where it is not available, this suggests an area where the provision of such data could create public benefits.

Future considerations and extensions of this work are possible. The methodology can be applied to other regions of the United States and other countries to examine differences in how wind and renewable energy projects are incentivized and financed, and the impact of incentive policies on location decisions elsewhere. Inferences regarding recent patterns of development in the WECC and other regions could also be more rigorously examined to understand how and why such patterns of development are changing. Future work could also extend the framework presented here to estimate and assess the impact of indirect support policies taken to ease the efforts necessary to expand renewable energy development, such as reductions in regulatory burdens or simplified permitting processes on project cost and location decisions.

The use of cost modeling as presented can be applied beyond wind or renewable-energy development. Principles developed here could also be useful when applied to other areas and other types of economic development where incentive policies that affect development costs and fiscal revenue choices are considered. Though methods presented here are applied to wind-energy development in the western United States, they can be applicable beyond the United States and the renewable energy sector to any situation where tax and other financial incentives are used to attract large private economic development projects. Understanding such impacts using cost-modeling can allow policymakers to better weigh the tradeoffs of policy or incentive choices, and to better achieve economic development goals.

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