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

Ben Cook and Robert Godby
Motivation

Many states and local governments have identified wind development as a potential means of diversification and economic growth:

- In the west this is particularly true in rural and energy producing communities impacted by the energy transition.

The development market for wind may be thought of as competitive in the west (Godby, Taylor and Coupal, 2018):

- State and local governments are/have considered incentives and tax policy as a means of affecting development.

No recent estimates in the literature on tax or incentive elasticities:

- Most recent work that may be relevant: Hitaj (2013)
Unsubsidized Wind LCOE

Wind 9-Year Percentage Decrease: \( (69\%)^{(1)} \)

Wind 9-Year CAGR: \( (12\%)^{(2)} \)

$LCOE$ $/\text{MWh}$

$\text{LCOE Version}\
\begin{array}{cccccccccc}
3.0 & 4.0 & 5.0 & 6.0 & 7.0 & 8.0 & 9.0 & 10.0 & 11.0 & 12.0 \\
$169 & $148 & $92 & $95 & $95 & $81 & $77 & $62 & $60 & $56 \\
\end{array}$
Using tax incentives or incentives to attract wind development creates a potential policy tradeoff.

- Pits potential foregone revenue against greater economic activity
- Revenue-strapped communities raising taxes risk losing development

Given the lack of tax elasticity estimates, there is a demand to understand how tax policy affects relative development costs in specific locations.

This project attempts to develop such after-tax cost estimates across states in the western United States.
Contribution

The study documents state tax differences in wind taxation across the western United States WECC region.

Estimates how these differences affect relative wind development costs by state.

Develops a detailed capital structure model to understand how different types of taxes and tax composition affect cost of wind development.

Considers whether it may be possible for states to avoid a tax/development tradeoff by changing the way they tax, and then how much they tax.
Potential Wind Capacity at 140-Meters Hub Height

35% or Higher
Gross Capacity Factor

2014 U.S. Wind Industry Average Turbine

Area (sq km)

- 0
- < 100
- 100 - 200
- 200 - 300
- 300 - 400
- > 400
- Land exclusions

This map illustrates general wind resource potential only and is not suitable as a siting tool. More detailed site and wind speed data, as well as coordination with relevant authorities, are needed to thoroughly evaluate appropriate wind energy development at any given location.

Data sources: AWS Truepower, National Renewable Energy Laboratory

This map was produced by the National Renewable Energy Laboratory for the Department of Energy. February 2015
# State Wind Taxation Treatment and Incentives

<table>
<thead>
<tr>
<th>State</th>
<th>No Sales Taxes/Exempt</th>
<th>No Wind-Specific Taxes</th>
<th>Property Tax Incentives</th>
<th>State Incentives (credits)</th>
<th>No Gross Revenue Tax</th>
<th>No Income Tax/Exempt/Credit</th>
<th>Other Incentives</th>
</tr>
</thead>
<tbody>
<tr>
<td>WY</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
<td>X</td>
<td>X</td>
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<tr>
<td>NM</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>IRBs</td>
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<tr>
<td>MT</td>
<td>X</td>
<td>X</td>
<td>X</td>
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<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>CO</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>CA</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OR</td>
<td>X</td>
<td>X</td>
<td>X</td>
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<td>X</td>
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<td></td>
</tr>
<tr>
<td>WA</td>
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<td></td>
<td></td>
<td></td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>ID</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
<td>X</td>
<td></td>
<td>Financing</td>
</tr>
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<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>AZ</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>NV</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
<td>X</td>
<td></td>
<td>X</td>
</tr>
</tbody>
</table>
Compute the estimated *Levelized Cost of Energy* (LCOE) for a specific wind farm configuration.

Levelized cost of energy: required revenue necessary per MWh to break even over the lifetime of a facility.

The modeling framework estimates the LCOE for a wider variety of factors, including:

- State tax policy,
- Wind resource quality assumed
- Financing and other cost factors.
We assume a competitive market for wind development

We do NOT assume Power Purchasing Agreement (PPA) levels.

Instead – consistent with other methods of LCOE estimation (e.g. Lazard) we assume “cost” of energy in each state achieves industry standard required levels of return to investors.

- Owners receive 10% return on investment
- Tax-equity investors receive 8.5%

=> Modeled LCOE cost outcomes are the prices needed to ensure investors get their required rate of return (but not more).
# Cost Assumptions Across all States

<table>
<thead>
<tr>
<th>Cost Factor</th>
<th>Assumed Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Output Capacity</td>
<td>300 MW</td>
</tr>
<tr>
<td>Total Cap costs*</td>
<td>1610 $/MW</td>
</tr>
<tr>
<td>Share of System Costs subject to sales tax</td>
<td>67%</td>
</tr>
<tr>
<td>Fixed O&amp;M Annual Cost</td>
<td>28 $/kW</td>
</tr>
<tr>
<td>Fixed O&amp;M inflation</td>
<td>1.5%</td>
</tr>
<tr>
<td>Variable Cost</td>
<td>0</td>
</tr>
<tr>
<td>Cap Factor degradation rate</td>
<td>1%</td>
</tr>
<tr>
<td>Construction time</td>
<td>12 months</td>
</tr>
<tr>
<td>Facility Life</td>
<td>20 or 30 years</td>
</tr>
<tr>
<td>Share of Financing using traditional debt</td>
<td>50%</td>
</tr>
<tr>
<td>Cost of Debt</td>
<td>6%</td>
</tr>
<tr>
<td>Cost of Tax-Equity</td>
<td>8.5%</td>
</tr>
<tr>
<td>Cost of Direct Equity</td>
<td>10%</td>
</tr>
<tr>
<td>Year of construction start</td>
<td>2018</td>
</tr>
<tr>
<td>Year of operation start</td>
<td>2019</td>
</tr>
<tr>
<td>Federal PTC value</td>
<td>19 $/MWh</td>
</tr>
<tr>
<td>PTC inflation</td>
<td>1.1%</td>
</tr>
</tbody>
</table>

Sources: DoE (2018), and expert solicitation. Values are in current dollars.
State-Specific cost assumptions:

- Regional costs of construction and Operation (O&M) vary by state –
  - Inflate or deflate equipment, construction, O&M by the following values

<table>
<thead>
<tr>
<th>State</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>AZ</td>
<td>96%</td>
</tr>
<tr>
<td>CA</td>
<td>122%</td>
</tr>
<tr>
<td>CO</td>
<td>94%</td>
</tr>
<tr>
<td>ID</td>
<td>98%</td>
</tr>
<tr>
<td>MT</td>
<td>96%</td>
</tr>
<tr>
<td>NM</td>
<td>92%</td>
</tr>
<tr>
<td>NV</td>
<td>104%</td>
</tr>
<tr>
<td>OR</td>
<td>105%</td>
</tr>
<tr>
<td>UT</td>
<td>96%</td>
</tr>
<tr>
<td>WA</td>
<td>106%</td>
</tr>
<tr>
<td>WY</td>
<td>94%</td>
</tr>
</tbody>
</table>

Source: U.S. Army Corps of Engineers (USACE, 2017)
**State Specific Capacity Factors**

Range: Maximum = modeled value at top 5% of WECC wind sites
Minimum = 35% constant across all states

<table>
<thead>
<tr>
<th>State</th>
<th>Estimated Net CF Possible yr. 1 (top 5% of land)</th>
<th>Net CF Yr. 20 using 1% Degradation Rate</th>
<th>Constant CF Yr. 1</th>
<th>Net CF Yr. 20 using 1% Degradation Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>WY</td>
<td>50.5%</td>
<td>41.7%</td>
<td>35%</td>
<td>28.9%</td>
</tr>
<tr>
<td>NM</td>
<td>50.5%</td>
<td>41.7%</td>
<td>35%</td>
<td>28.9%</td>
</tr>
<tr>
<td>MT</td>
<td>50.5%</td>
<td>41.7%</td>
<td>35%</td>
<td>28.9%</td>
</tr>
<tr>
<td>CO</td>
<td>49.6%</td>
<td>41.0%</td>
<td>35%</td>
<td>28.9%</td>
</tr>
<tr>
<td>CA</td>
<td>41.5%</td>
<td>34.3%</td>
<td>35%</td>
<td>28.9%</td>
</tr>
<tr>
<td>OR</td>
<td>40.6%</td>
<td>33.5%</td>
<td>35%</td>
<td>28.9%</td>
</tr>
<tr>
<td>WA</td>
<td>40.6%</td>
<td>33.5%</td>
<td>35%</td>
<td>28.9%</td>
</tr>
<tr>
<td>ID</td>
<td>40.6%</td>
<td>33.5%</td>
<td>35%</td>
<td>28.9%</td>
</tr>
<tr>
<td>UT</td>
<td>37.9%</td>
<td>31.3%</td>
<td>35%</td>
<td>28.9%</td>
</tr>
<tr>
<td>AZ</td>
<td>37.0%</td>
<td>30.6%</td>
<td>35%</td>
<td>28.9%</td>
</tr>
<tr>
<td>NV</td>
<td>34.3%</td>
<td>28.3%</td>
<td>35%</td>
<td>28.9%</td>
</tr>
</tbody>
</table>

Both degrade at a rate of 1% per year.

Modeling:

- Define Project Assumptions:
  - Project Capacity (A)
  - National average installed cost (B)
  - Regional cost multiplier (C)
  - Share of installed costs (sales) taxable (D)
  - Sales tax rate (E)

- Pre-tax installed cost (F) = A x B x C
- Sales taxes payable (G) = D x E x F
- Post sales tax installed System Cost (H) = F + G

- Define Financing Assumptions:
  - Installed System Cost (H)
  - Traditional debt share (I)
  - Traditional debt int. Rate (J)
  - System life (K)
  - Tax-equity Rate (L)
  - Capacity Factor (M)
  - Cap factor deg. rate (N)
  - PTC value (O)
  - PTC value inflation rate (P)
  - Direct Equity Rate (Q)

- Traditional Debt Cost (S) computed as an amortized annual debt payment at rate (J) paid over system life (K) less two years for buffer

- Total Annual Finance Costs (V) = S + U

- Total Cost of Energy before Taxes = V + AA

- Average Cost of Energy = Total cost / total MWh produced over life of Project

- Compute Operating Costs (OPEX):
  - National Average Annual Fixed Operating and Maintenance (O&M) cost (T)
  - OPEX inflation rate (Y)
  - Regional cost multiplier (C)

- Annual Insurance cost (Y) = 0.4% x H

- Decommissioning Reserve Contribution (Z) computed at cost of $50,000/MW financed as a sinking fund earning 2.2% annually

- Annual OPEX Costs (AA) = [(WAC) + Y + Z] inflated annually at rate X

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

1. **Define Tax Assumptions**
   - Property tax rate (A)
   - State specific assumptions regarding depreciated value floor (B)
   - System Life (C)

2. **Compute Basis for tax assessment**
   - Use System Cost (see Figure X)

3. **Adjusted Basis (E) for non-depreciable (land) value**
   - \( (D) \times 0.975 \)

4. **Compute straight-line depreciation of (E) annually using anyfloor assumptions (B)**

5. **Levelize Property Tax payments**

6. **Levelized Property Tax Costs**

7. **Compute Wind Tax Cost (Wyoming only)**

8. **Define Tax Assumptions**
   - System capacity (A)
   - Capacity factor (B)
   - System Life (C)
   - Annual Output Degradation (D)
   - Tax Rate/MWh (E)
   - Year tax begins (F)

9. **Compute annual output MWh**
   - In each year (G) = \( A \times B \times D \times 8760 \) given starting year of tax (F)

10. **Compute annual Wind Tax assessment in each year (H) = E \times G \) given (F)

11. **Levelize Wind Tax payments**

12. **Levelized Wind Tax Costs**
Tax modeling:

1. Compute Income Tax Costs
   - Define Tax Assumptions:
     - System capacity (A)
     - Capacity factor (B)
     - System Life (C)
     - Annual Output Degradation (D)
     - Federal Tax Rate (E)
     - State Tax Rate (F)
     - Convergence Limit (G)
   - Compute Levelized Cost of energy (H) and annual cash flows (Figure X)
     - Assume this is the price energy is sold for.

2. Compute Levelized Income Tax Costs
   - Add levelized Income Tax Cost to Levelized Cost (J) = H + I

3. Recompute Levelized Income Tax Costs, Levelized Cost of Energy and cash flows using (I) as the price energy sold for (I)

4. Is change in new I less than 0?
   - No
   - Levelized Income Tax Costs
   - Yes

5. Compute Gross Receipts Tax
   - Define Tax Assumptions:
     - System capacity (A)
     - Capacity factor (B)
     - System Life (C)
     - Annual Output Degradation (D)
     - Tariff (E)
     - Convergence Limit (F)
   - Compute Levelized Gross Receipts Tax Cost (M) = levelized value of Gross Receipts Tax payable in each year (total MWh output per year / 8760) x value of energy (G) x C

6. Add levelized Gross Receipts Tax Cost to Levelized Cost (J) = G + K

7. Recompute Levelized Gross Receipts Tax Cost using (I) as value of energy (H)

8. Is change in new M less than 0?
   - No
   - Levelized Gross Receipts Tax Cost
   - Yes

Note on discounting...

Costs presented are not presented as present values

- Consistent with Lazard estimates
- Increases transparency
  - Discounting makes taxes paid earlier in project life more important
    - exaggerates effect of sales tax (Wyoming costs would worsen if this convention observed, MT, CO, NM would not).
    - Implies a time preference exists

Addresses fact that governments often prefer revenue flows over early one-time payments.

- There are political and legal constraints local and state governments face that make dealing with one-time payments difficult.
Presentation
Methodology

Cost estimates presented as a range for each state

Each bar shows cost where only taxes differ (right end of figure)

- state capacity factors are set to 35%
- Regional construction/O&M cost differences ignored.

Each bar shows cost when taxes, wind quality and construction/operations costs included (left end of figure)

- state capacity factors are set to estimated values shown
- Regional construction and O&M cost differences included
Estimated Western Wind Costs with Taxes
(20-year project life)

<table>
<thead>
<tr>
<th>State</th>
<th>$/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>California</td>
<td>$66.87 - $67.11</td>
</tr>
<tr>
<td>Nevada</td>
<td>$61.97 - $66.35</td>
</tr>
<tr>
<td>Washington</td>
<td>$58.17 - $66.26</td>
</tr>
<tr>
<td>Arizona</td>
<td>$55.16 - $62.30</td>
</tr>
<tr>
<td>Oregon</td>
<td>$53.53 - $61.56</td>
</tr>
<tr>
<td>Utah</td>
<td>$51.60 - $59.97</td>
</tr>
<tr>
<td>Idaho</td>
<td>$49.60 - $62.10</td>
</tr>
<tr>
<td>Wyoming (w/ $5 wind tax)</td>
<td>$38.99 - $65.91</td>
</tr>
<tr>
<td>New Mexico (w/o IRB)</td>
<td>$36.95 - $67.74</td>
</tr>
<tr>
<td>Wyoming</td>
<td>$35.44 - $62.37</td>
</tr>
<tr>
<td>Colorado</td>
<td>$34.72 - $60.44</td>
</tr>
<tr>
<td>Montana</td>
<td>$34.43 - $59.86</td>
</tr>
<tr>
<td>New Mexico</td>
<td>$32.18 - $60.16</td>
</tr>
</tbody>
</table>
Comparison of tax costs by state per MWh*

*Assumes 20-year life
Lack of an income tax has little effect on cost of wind

- States without income taxes often argue this creates development advantages.
- Wind facilities have very little income tax liability.

Most important element of costs are those due to financing

- Ability to reduce financing costs creates distinct cost advantages (e.g. bonding programs as used in NM).
- Sales taxes most costly form of tax due to fact these costs often need to be financed as they occur before operation occurs.

Production incentives/disincentives very important also – create potentially large cost and risk impacts

Annual taxes such as property, income, gross receipts or royalties likely less important

- Consistent with previous research (e.g. Hataj, 2013)
Can we Tax “Smarter”?
Reducing the Development/Taxation Tradeoff

1) Use strategies like NM’s that reduce financing costs: lowest cost to develop, high tax revenues

Create industrial revenue bonding similar to NM’s, and allow PILOT negotiations to share resulting cost savings.
2) Tax differently.

- Avoid using taxes that
  - Impose a fixed cost component on developers (production tax)
  - Impose an upfront cost that requires financing (sales taxes).

Use taxes that create a more certain revenue stream

- Use of a royalty on gross receipts could replace sales and production taxes, creating predictable revenue streams that are not subject to economic or energy cycles.
Wind development offers significant development and revenue opportunities to the state.

Increasing taxes could undermine this opportunity significantly.

- Major tax increases could significantly change wind siting decisions.

Tradeoff between development and revenue may be overcome if you change how you tax, then how much you tax.

- There is potential to have your cake and eat it too.
Potential to have your cake and eat it too…

• Evaluated a hypothetical tax change in Wyoming
  • Eliminate of the sales tax
  • Eliminate of the production tax
  • Maintain current property tax rules
  • Impose 6% royalty charged on value of electricity sold (same as state oil and gas severance rate).

• Result:
  • Cost of wind development for a 20-year project falls 1.5%, halving cost differences between Wyoming and MT and CO.
  • Taxes collected per MWh rise by 8.3%.
  • Reliable revenue stream created over life of project.