November 8, 2017

Comments of Brian Fadie
Clean Energy Program Director
Montana Environmental Information Center

Commissioners,

Thank you for the opportunity to comment on the Avista Corp 2017 Integrated Resource
Plan. Utilities and states in the Pacific Northwest are inexorably tied together and I
appreciate the commission holding this hearing in a location more accessible to those
who reside on the eastern side of the BPA service territory.

After reviewing the IRP, I would like to present information to the commission that may
help paint a more complete picture about resource options available in the region that
may not have been fully explored. Specifically, I will touch on the low cost, high value
wind and energy storage options available in Montana.

First, a big picture update. Just this week the respected financial asset management firm
Lazard released its 11th annual report on domestic energy cost trends.[1] I will provide a
copy of the report to the commission. It shows another year of continued cost declines for
wind energy across the country, with the resource dropping to as low as $30 per
megawatt hour in high wind areas. Put simply: wind energy is cheap and getting cheaper.

Utilities like Avista can benefit from access to this low cost, high capacity factor wind.
Specifically, Figure 3.15 on page 3-22 of the IRP demonstrates that Avista is a winter
peaking utility and is predicted to remain so through the planning horizon, making winter
peaking wind the most valuable. This is precisely the type of wind Montana has in
abundance, however the IRP may not have fully considered this potential resource.

In regards to the IRP's evaluation of wind energy resources, page 10-7 states, "The first
[data set used for wind evaluation] is BPA balancing area wind data. The second is
NREL-modeled data between 2004 and 2006." However, Montana's best wind resources
are just outside of BPA's balancing area on the eastern side of the state. It would also
seem prudent to evaluate wind resource information more recent than a decade old.

The IRP states on page 9-6 that "Wind capacity factors in the Northwest range between
25 and 40 percent depending on location. This plan assumes Northwest wind has a 37
percent average capacity factor." Speaking specifically to Montana wind, on page 10-10,
the IRP gives Montana wind a capacity factor of 37%. While this would be a good
capacity factor nationally, Montana wind actually beats this and by a wide margin.
Multiple recent analyses and those that included central and eastern Montana wind have
shown much higher capacity factors, particularly in winter peaking hours.

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[1] https://www.lazard.com/perspective/levelized-cost-of-energy-2017/

In 2016, the Northwest Power and Conservation Council conducted an analysis comparing central Montana wind with that of Columbia River Gorge wind. The council found that central Montana wind had a 48% capacity factor during winter high load hours and concluded, "Montana wind correlates better with timing of regional winter peak load." [2,3]

Also in 2016, the consultant firm Energy Strategies conducted an analysis of Montana wind in the context of comparing it to Oregon and Washington wind resources. Energy Strategies concluded Montana wind has capacity factors in the 50% to 66% range, with winter peak hours reaching as high as 70%.[4] This was significantly higher than the 45% capacity factors found for Washington and Oregon wind.[5] The study concluded, "Montana wind is more plentiful and generally of higher quality than Washington or Oregon wind."[6]

The geographic diversity Montana wind can bring to utilities like Avista is also of considerable value, both decreasing integration needs and increasing the resource's ability to meet peak demand. The IRP rightfully acknowledges this on page 9-6, noting "Adding Montana wind will be less costly to integrate due to its different generation profile as compared to Palouse Wind, and it may add up to a 7.5 percent capacity contribution when combined with Palouse Wind's expected output on to meet the single-hour winter peak."

In addition to cheap, clean, and valuable wind energy found in Montana, I would also like to highlight for commissioners the existence a noteworthy energy storage opportunity that the IRP makes only passing reference to. The Gordon Butte Pumped Hydro storage facility would be located in central Montana just a handful of miles from the Colstrip transmission lines.[7] Pumped hydro energy storage is a mature technology that can bring significant value to a utility, including providing emissions free on-demand capacity, avoiding curtailment, and increasing transmission utilization. The biggest barrier to these projects is usually the fact that they require specific geologic formations to operate. Luckily, central Montana has such a formation. This 400-megawatt project has already received its FERC license and is ready to begin talks with utilities.

In sum, Avista customers would benefit from a wider and more comprehensive analysis of low cost resource options available in the region. Specifically, Montana wind and energy storage needs to be more fully evaluated. I encourage the commission to consider this information when providing guidance to Avista for its next IRP.

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[2] Page 8, https://www.nwcouncil.org/media/7150484/3.pdf
[3] Page 13, Id.
[4] Page 8-9, "Assessment Of The Cost Competitiveness of Montana Wind Energy," Energy Strategies, 2016.
[5] Page 8, Id.
[6] Page 28, Id.
[7] Page 21, https://www.nwcouncil.org/media/7491042/p3.pdf

PPC Results

- With the high-level assumptions and the understanding that this study did not constitute an interconnection request, transmission service request or path rating, there was nothing to suggest that replacing coal with wind/gas will significantly harm the transmission system
- Any new generation will be fully analyzed

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NorthWestern Energy

- NWE currently has 36 active projects
  - Hydro, 1 project: 450 MW
  - Solar, 25 projects: 1161 MW
  - Wind, 10 projects: 1774 MW
- Total of 3385 MW in the GIA queue

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ublic Policy Consideration Study

- PPC study submitted to study the transmission impact of closing down Colstrip Units 1, 2 and 3 and replacing with either wind alone or a combination of wind and gas

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PPC Study

- Started with a case that had heavy Path 8 westbound transfers
- Modeled in all the possible combinations of coal-fired generation, wind and gas
  - The new wind was analyzed at three different dispatch levels, 0%, 35% and 100%
- Ran steady state and transient stability

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NTTG TWG Update

NTTG Planning Committee Meeting

April 12, 2017

NORTHERN TIER
TRANSMISSION GROUP

Public Policy Consideration Study Update

NTTG Planning Committee Meeting

April 12, 2017

NORTHERN TIER
TRANSMISSION GROUP

PPC Update: Purpose

- To understand the transmission implications of replacing approximately 1500 MW of Coal with Wind; of particular concern are the west-bound flows from Montana to the Northwest on Path 8

PPC Update: Process

- Retire Colstrip unit 3 in addition to the already retired Colstrip units 1 and 2

- Model in 1494 MW of wind at the Broadview 500 kV bus using generic Type 4 machines

- Dispatch the new wind at Broadview at 0%, 35% and 100%

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PPC Update: Process

- Run steady-state analysis on the three cases

- Determine if voltage violations inhibit flows on Path 8; if so, then model in a synchronous condenser

- Run dynamics analysis on the appropriate cases
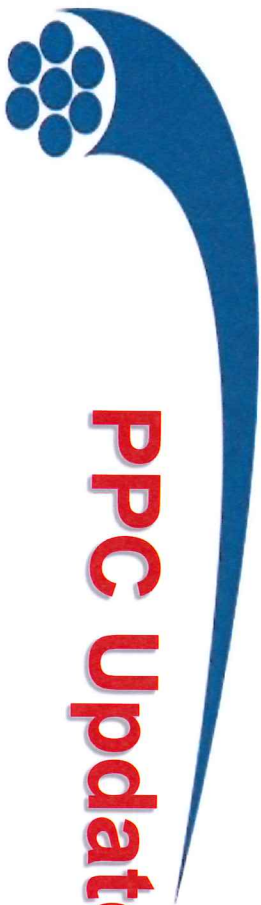
PPC Update: Process

- Reduce the wind from 1494 MW to 1244 MW and add in 250 MW natural gas generation plant in Billings

- Dispatch the wind at Broadview at 0%, 35%, 100%

- Run dynamics on this new case

PPC Update: Process

- Choose the "best" case from the studied cases and run PCM
  - The "best" case has the fewest violations and the highest exports on Path 8

PPC Update
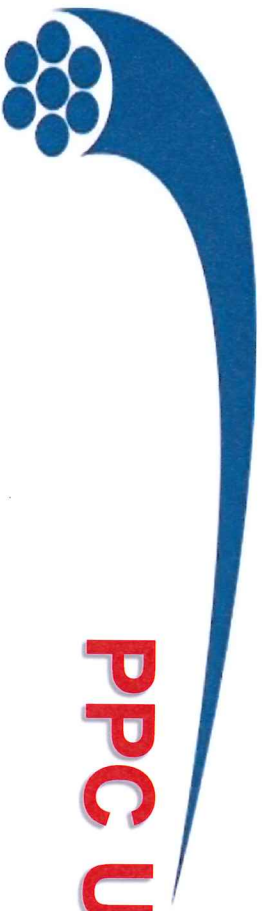
- Started with the Montana Maximum Path 8 case, turned off Colstrip Unit 3 and modeled in 1494 MW of wind on the Broadview 500 kV bus

- Dynamics were of particular concern; we were able to successfully apply the DYD file from the Summer Peak case to the PPC case with the new wind at Broadview
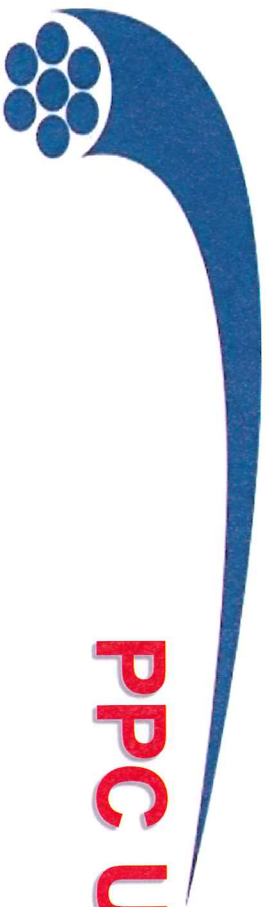
PPC Update

- Discussion Topic: Flows on Path 8

- When the proposal originally came in, the "Path 8" case would have had all 4 units on at Colstrip

- With all 4 units on at Colstrip, it is very easy to replace coal with wind and obtain like flows on Path 8

PPC Update
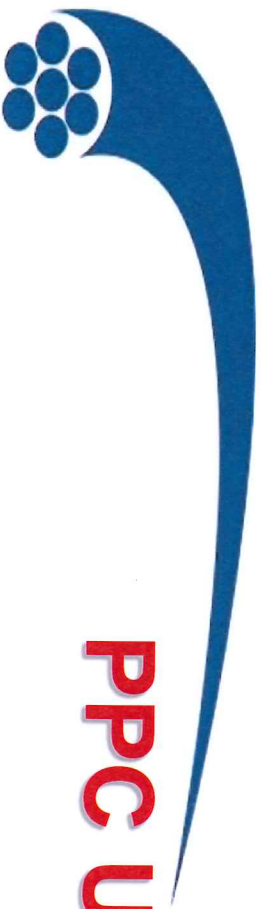
- Discussion Topic: Flows on Path 8

  - There is approximately 2200 MW exporting on Path 8 in case without Colstrip Units 1 and 2

  - It was decided to keep approximately 2200 MW exporting on Path 8 with the retirement of Colstrip Unit 3 and the addition of the wind at Broadview

  - Historically, it is the MW flow on Path 8 that governs the response to outages

PPC Update: Path 8 MW

Case Description	Montana to the Northwest (MW)
Case for Plan (Case "C")	2189
CS units 1, 2 and 3 offline, new BV wind at 100%	2203
CS units 1, 2 and 3 offline, new BV wind at 35%	1382
CS units 1, 2 and 3 offline, new BV wind at 0%	926
CS units 1, 2 and 3 offline, new BV wind at 100%, with the gas plant	2194
CS units 1, 2 and 3 offline, new BV wind at 35%, with the gas plant	1522
CS units 1, 2 and 3 offline, new BV wind at 0%, with the gas plant	1136
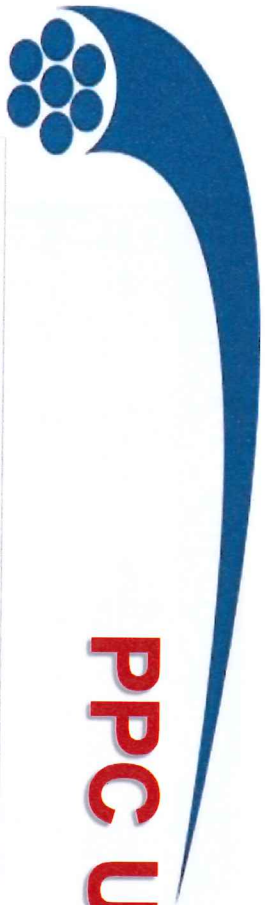
Broadview 500 kV Bus Voltage After Double Broadview Garrison Outage

PPC Update

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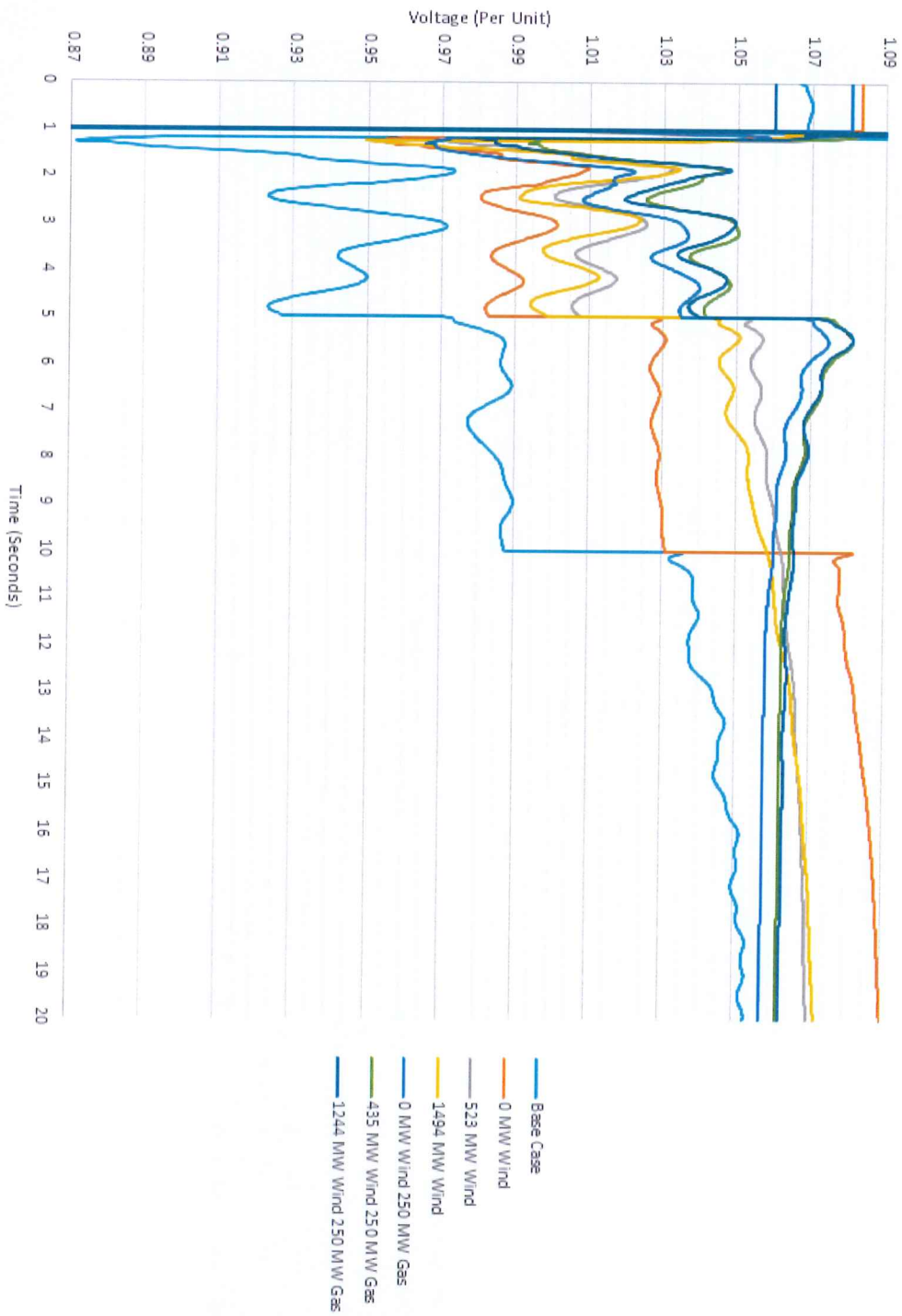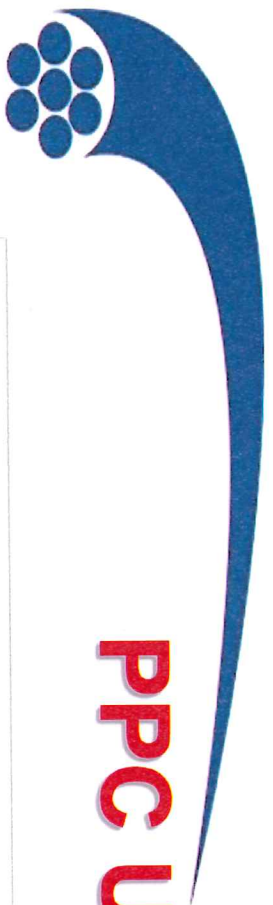
Broadview 500 kV Bus Frequency After Double Broadview Garrison Outage

PPC Update

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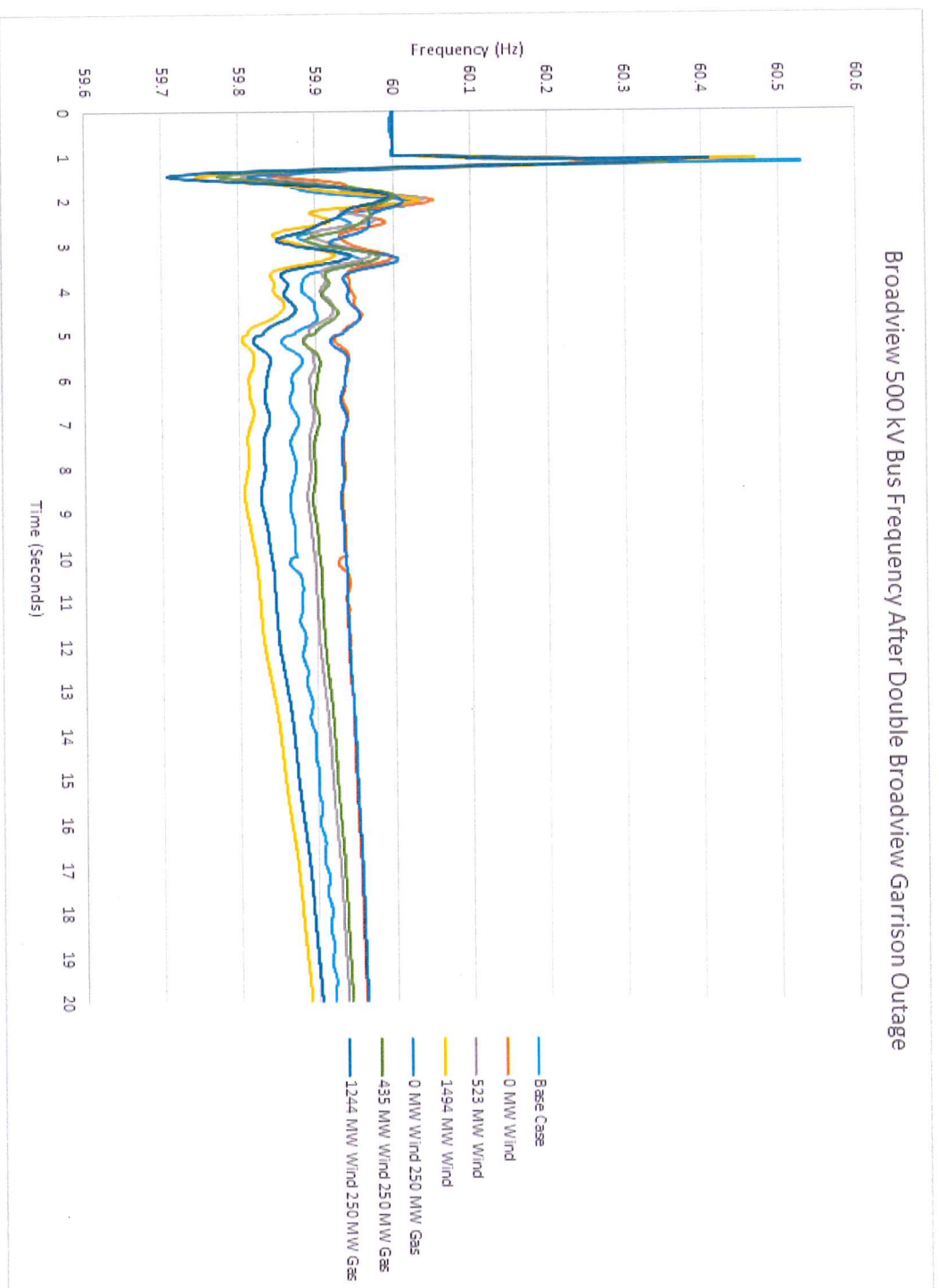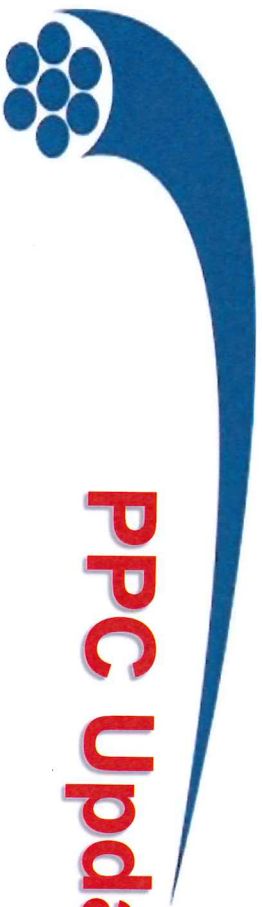
PPC Update: PCM

- Production Cost Modeling was run on the case that had both wind and gas to replace the coal

- There was no congestion observed as a result of the change in generation

PPC Update: Considerations

- This analysis does not constitute a GIA/TSR/Path Rating study and as such, does not guarantee that future studies will yield different results

- The new wind at Broadview was assumed to meet all voltage requirements of an interconnection, however, there may be equipment needed to meet those requirements in a request. The collector system was not modeled
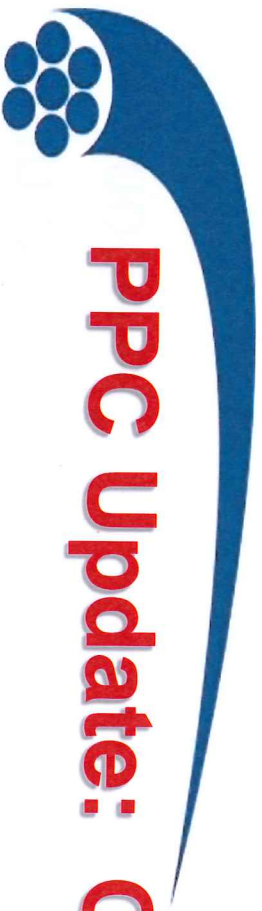
PPC Update: Considerations

- SSR (subsynchronous resonance) was not considered

- The RAS for the new wind at Broadview was confirmed to be necessary, however, the timing/communications/interplay with the ATR would have to be fully analyzed in a GIA study

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PPC Update: Conclusions

- This high-level analysis suggests that it may be feasible to replace coal with wind or a combination of wind/gas

- The PCM suggests that replacing coal with wind/gas results in dispatch patterns that favor wind and hydro given the assumptions that went into this PCM run, but doesn't account for capital or other non-operational costs
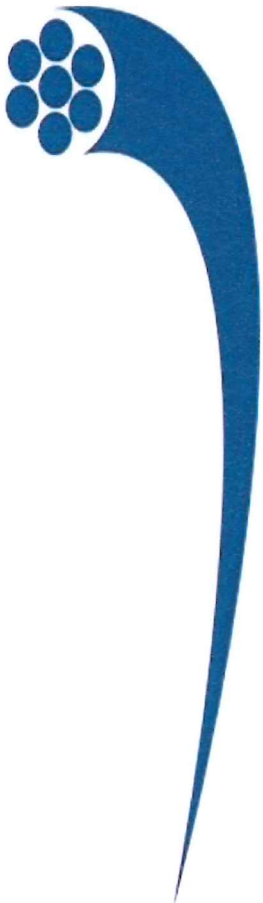
Questions

Montana vs. Pacific Northwest Wind
Cost Comparison

Prepared by:

Bill Pascoe, Pascoe Energy Consulting

December 2016

Biographical Information:

Bill Pascoe

Bill Pascoe is President of Pascoe Energy Consulting, a firm located in Absarokee, Montana and specializing in electricity supply and transmission issues. His clients include companies developing generation and transmission projects in Montana and surrounding states.

Mr. Pascoe was employed by The Montana Power Company and NorthWestern Energy for 25 years and served in key leadership positions including Vice President of Energy Supply and Sr. Vice President of Transmission.

Mr. Pascoe has been active in regional utility organizations and served terms as Chairman of the Pacific Northwest Utilities Conference Committee (PNUCC), Western Electricity Coordinating Council (WECC) and RTO West Board of Directors.

Mr. Pascoe is a Montana native and holds degrees in electrical and civil engineering from Montana State University.

John Leland

John Leland is a technical consultant for the Northern Tier Transmission Group ("NTTG") regional and interregional transmission planning processes. He retired from NorthWestern Energy in 2014 after 35 plus years of resource and transmission planning for the electric utility. John was a key player in the developing the policy and compliance responses to FERC Orders 890 and 1000 local, regional and interregional planning processes for NorthWestern Energy and NTTG.

He is an accomplished professional with successful experience in policy and regulatory compliance as well as analyzing and identifying solutions to complex technical problems.

This report summarizes findings of an analysis that compares the cost of Montana wind and Pacific Northwest wind delivered to utilities in Washington and Oregon.

Background

For many years, Montana wind advocates have been touting the advantages of Montana wind to potential utility purchasers in Washington and Oregon. The primary advantages of Montana wind are:

- Higher capacity factors due to the more robust wind resource in Montana.
- Wind shapes that provide relatively more output during winter daytime hours when Pacific Northwest demand for electricity is highest.
- Diversity that reduces the cost of integrating additional wind energy into Pacific Northwest power systems.

These advantages have historically been offset by the cost and uncertainty of securing transmission service between Montana wind projects and utilities in Washington and Oregon. As described later in this report, reasonable transmission solutions are available.

Recent developments have increased interest in Montana wind by Washington and Oregon utilities that will create market opportunities in the near future. These developments include:

- An agreement reached by the owners of Colstrip 1&2 (Puget Sound Energy (PSE) and Talen Energy) and environmental groups that commits to the closure of Colstrip 1&2 no later than 2022. In addition to creating a need for power to replace 600 MW of retired baseload generation, this agreement frees up 300 MW of firm transmission rights between Colstrip and the PSE system.

- Enactment of the Oregon Clean Electricity and Coal Transition Plan (SB1547) in the 2016 Oregon legislative session that increases the renewable portfolio standard for Portland General Electric (PGE) to 50% by 2040. This requirement coupled with the recent phased-out extension of the federal production tax credit (PTC) has created an incentive for early action by PGE.

These developments have led PSE and PGE to give serious consideration to Montana wind in their recent Integrated Resource Plan (IRP) processes. This may lead to a once-in-a-decade opportunity for these utilities to acquire Montana wind resources.

Models, Data Sources and Assumptions

For this analysis, delivered costs were determined using the PowerFin levelized cost model maintained by the Northwest Power and Conservation Council (NPCC)[1]. As explained below, basic inputs to the model were taken from the NPCC's Seventh Power Plan with certain assumptions specified by the author.

Resource Costs

Capital and operating costs for wind generators ($2,240/kw CapEx) and aeroderivative CTs ($1,111/kw CapEx) were taken from the Seventh Power Plan.

The capital cost of wind generation has fallen since the Seventh Power Plan with costs in the range of $1,800 to $2,000/kw commonly cited. Using lower current costs for wind generation would lower the costs for both Montana wind and Pacific Northwest wind, but would not have a significant impact on the relative cost comparisons which are the focus of this analysis.

Wind costs were developed with and without federal PTCs. Assumptions about PTCs effect the costs for Montana wind and Pacific Northwest wind, but did not have a significant impact on the relative cost comparisons which are the focus of this analysis.

The cost of capacity from aeroderivative CTs is used to calculate the capacity value of the Montana wind and Pacific Northwest wind, as discussed further below.

Wind Capacity Factors

The capacity factor for Pacific Northwest wind was assumed to be 34%. This is the capacity factor used in PSE's 2015 IRP[2] and in PGE's 2016 IRP.

Two capacity factors were tested for Montana wind – 40% and 45%. These values were selected to represent a reasonable range for fair (40%) to good (45%) Montana wind sites and to evaluate the sensitivity of the results to this important parameter.

Wind Capacity Value

Capacity value is the capability of a wind farm to contribute toward a utility system's resource adequacy or effective load carrying capability. In simple terms, increased capacity value from wind generation reduces the need for a utility to develop conventional peaking resources. For this analysis, capacity value from wind resources was assumed to reduce capacity needed from new aeroderivative CTs which is a logical choice to provide new capacity with flexibility to complement wind and other intermittent resources.

The capacity value for Pacific Northwest wind was assumed to be 10%. This is similar to the values in PSE's 2015 IRP, PGE's 2016 IRP and a recent NPCC study[3].

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[1] NPCC staff provided the PowerFin results that are the foundation of this analysis.
[2] PSE's 2017 IRP will use a 37% capacity factor to reflect improved efficiency from newer wind turbine technology. A similar improvement in capacity factor would be expected from applying new technology to Montana wind sites.
[3] System Capacity Contribution of Montana Wind Resources, presented at August 9, 2016 NPCC meeting.

A range of capacity values for Montana wind – 10%, 30% and 50% - were tested in this analysis to evaluate the sensitivity of the results to this important parameter.

- 10% was selected as a lower bookend assuming Montana wind and Pacific Northwest wind have similar capacity values.
- 30% was selected as a midrange value and is similar to the value for the first 300 MW of Montana wind in PGE's 2016 IRP.
- 50% was selected as an upper bookend and is similar to the values found in PSE's 2015 IRP and the recent NPCC study[4].

Capacity value is treated as a credit against wind generation costs in this analysis.

Transmission

Securing affordable transmission is key to making the delivered cost of Montana wind competitive with Pacific Northwest wind. It is generally understood that Montana wind delivered over newly constructed long-distance transmission lines in Montana and/or on the BPA system is too expensive to compete with Pacific Northwest wind delivered over existing BPA transmission facilities. Fortunately, lower cost transmission alternatives exist for several hundred MW of Montana wind.

For this analysis, Pacific Northwest wind is assumed to be delivered over BPA's existing transmission facilities at the current BPA Main Grid rate ($21.48/kw-year).

For Montana wind, three transmission options were considered:

Option #1 – One wheel on the NorthWestern Energy (NWE) transmission system at current rates ($39.96/kw-year)[5] and one wheel on the BPA Main Grid ($21.48/kw-year)[6].

Option #2 – A generator tie line (at a cost of $80/kw)[7] interconnecting at Broadview or Colstrip followed by three wheels on transmission rights currently used to deliver PSE's share of Colstrip 1&2 – PSE Colstrip transmission ($31.82/kw-year), BPA Montana Intertie ($7.18/kw-year) and BPA Main Grid ($21.48/kw-year).

Option #3 - A generator tie line (at a cost of $80/kw)[8] interconnecting at Broadview followed by wheeling on upgraded facilities between Broadview and Garrison ($160/kw)[9] and on the BPA Main Grid ($300/kw)[10]. Note that using the financing assumptions in the NPCC levelized cost model, the annual costs of the upgrades are less

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[4] See footnote 3.

[5] Transmission service studies performed by NWE for Gaelectric indicate that approximately 330 MW of transmission capacity is available between the Harlowton, MT area and the BPA Main Grid with modest upgrades that would be rolled into NWE's current transmission rate.

[6] Recent conversations with BPA staff indicate that 200 MW of transmission is available for new Montana exports with the installation of a generator tripping scheme for certain contingencies.

[7] 70 miles of 230 kV wood H-frame transmission at $500,000/mile = $35 million, 450 MW capacity

[8] See footnote 7.

[9] $73 million in upgrades from Gaelectric transmission service study, 450 MW capacity

[10] $137 million in upgrades ($115 million from BPA 2010 NOS ROD escalated 3% per year), 450 MW capacity

than the current transmission rates used in Option #2. Under current FERC and BPA pricing policies these upgrades would be rolled into current rates and Montana wind exports would pay the same transmission costs as in Option #2.

Transmission losses were applied to each option based on current tariffs:

- Gen Tie – 3% (estimated)
- NWE – 4%
- PSE Colstrip / BPA MT Intertie – 3%
- BPA Main Grid – 1.9%

Integration Costs

BPA wind integration costs from the Seventh Power Plan ($14.76/kw-year) were included for all options.

Results

Results of the analysis are summarized in the following tables. In these tables, a positive value (blue shading) indicates the percentage by which the delivered cost for Montana wind exceeds Pacific Northwest wind. A negative value (green shading) indicates the percentage by which the delivered cost for Montana wind is less than Pacific Northwest wind.

Graphical depictions of the results for different assumptions for Montana wind capacity factors, Montana and Pacific Northwest wind capacity values, PTCs and transmission costs are provided in the Appendix.

Table 1A. MT Wind vs WA/OR Wind, Delivered Cost Comparison MT 40% CF, Full PTC

WA CV	MT CV	Tx Option		
		#1	#2	#3
0%	0%	0%	4%	-5%
10%	10%	0%	5%	-4%
10%	30%	-10%	-6%	-15%
10%	50%	-20%	-16%	-25%

Table 1B. MT Wind vs WA/OR Wind, Delivered Cost Comparison MT 40% CF, No PTC

WA CV	MT CV	Tx Option		
		#1	#2	#3
0%	0%	0%	4%	-3%
10%	10%	1%	5%	-3%
10%	30%	-8%	-4%	-12%
10%	50%	-17%	-13%	-21%

Table 2A. MT Wind vs WA/OR Wind, Delivered Cost Comparison MT 45% CF, Full PTC

WA CV	MT CV	Tx Option		
		#1	#2	#3
0%	0%	-13%	-9%	-17%
10%	10%	-12%	-8%	-16%
10%	30%	-21%	-17%	-26%
10%	50%	-30%	-27%	-35%

Table 2B. MT Wind vs WA/OR Wind, Delivered Cost Comparison MT 45% CF, Full PTC

WA CV	MT CV	Tx Option		
		#1	#2	#3
0%	0%	-11%	-7%	-14%
10%	10%	-10%	-6%	-13%
10%	30%	-18%	-14%	-22%
10%	50%	-26%	-23%	-30%

High level conclusions are as follows:

For Montana Wind with 40% CF and Full PTCs:

- Assuming no capacity value or 10% capacity value for Pacific Northwest wind and Montana wind, delivered costs for Montana wind range from 5% higher to 5% lower than Pacific Northwest wind depending on the transmission option selected.

- Assuming 10% capacity value for Pacific Northwest wind and 30% capacity value for Montana wind, delivered costs for Montana wind range from 6% to 15% lower than Pacific Northwest wind depending on the transmission option selected.

- Assuming 10% capacity value for Pacific Northwest wind and 50% capacity value for Montana wind, delivered costs for Montana wind range from 16% to 25% lower than Pacific Northwest wind depending on the transmission option selected.

For Montana Wind with 45% CF and Full PTCs:

- Assuming no capacity value or 10% capacity value for Pacific Northwest wind and Montana wind, delivered costs for Montana wind range from 8% to 17% lower than Pacific Northwest wind depending on the transmission option selected.

- Assuming 10% capacity value for Pacific Northwest wind and 30% capacity value for Montana wind, delivered costs for Montana wind range from 17% to 26% lower than Pacific Northwest wind depending on the transmission option selected.

- Assuming 10% capacity value for Pacific Northwest wind and 50% capacity value for Montana wind, delivered costs for Montana wind range from 27% to 35% lower than Pacific Northwest wind depending on the transmission option selected.

Assuming no PTCs, the cost advantage of Montana wind is reduced slightly (from 2% to 5%) depending on the particular case being considered.

These estimates of the cost advantage of Montana wind are conservative for the following reasons:

- This analysis calculates the capacity value difference between Pacific Northwest wind and Montana wind. However, it does not capture the difference in energy value from seasonal and diurnal shapes. Relatively more Montana wind is produced during the high-value winter season and relatively more Pacific Northwest wind is produced during the low-value spring season.

- This analysis assumes wind integration costs are the same for Pacific Northwest wind and Montana wind. However, due to diversity, Montana wind will be less costly to integrate into the Pacific Northwest system, especially for the first Montana wind to be integrated.

- This analysis assumes a relatively long (70 mile) generator tie line for Transmission Options #2 and #3. Montana wind projects located nearer to Broadview or Colstrip would reduce or eliminate the tie line costs and losses which make up about 5% to 6% of the total delivered costs. These costs would also be avoided if the Gordon Butte pumped hydro project is successfully developed and the very high quality wind resources in that area access the Colstrip transmission lines through the Gordon Butte interconnection.

- Transmission Option #2 includes transmission rates for PSE Colstrip transmission and the BPA Montana Intertie. Closure of Colstrip 1&2 will free up 300 MW of transmission capacity on these facilities. The cost of this capacity will continue to be borne by PSE ratepayers unless this capacity is used for some other purpose such as delivering Montana wind. Treating these as sunk costs reduces total delivered costs for Montana wind by between 11% and 17%.

APPENDIX

Chart 1. PNW Capacity Value – 0%, MT Capacity Value – 0%, Full PTCs

Chart 2. PNW Capacity Value – 10%, MT Capacity Value – 10%, Full PTCs

Chart 3. PNW Capacity Value – 10%, MT Capacity Value – 30%, Full PTCs

Chart 4. PNW Capacity Value – 10%, MT Capacity Value – 50%, Full PTCs

Chart 5. PNW Capacity Value – 0%, MT Capacity Value – 0%, No PTCs

Chart 6. PNW Capacity Value – 10%, MT Capacity Value – 10%, No PTCs

Chart 7. PNW Capacity Value – 10%, MT Capacity Value – 30%, No PTCs

Chart 8. PNW Capacity Value – 10%, MT Capacity Value – 50%, No PTCs

Chart 1

MT vs WA/OR Wind Comparison
Capacity Credit: WA/OR - None, MT - None
Full PTC

Chart 2

MT vs WA/OR Wind Comparison
Capacity Credit: WA/OR - 10%, MT - 10%
Full PTC

Chart 3

MT vs WA/OR Wind Comparison
Capacity Credit: WA/OR - 10%, MT - 30%
Full PTC
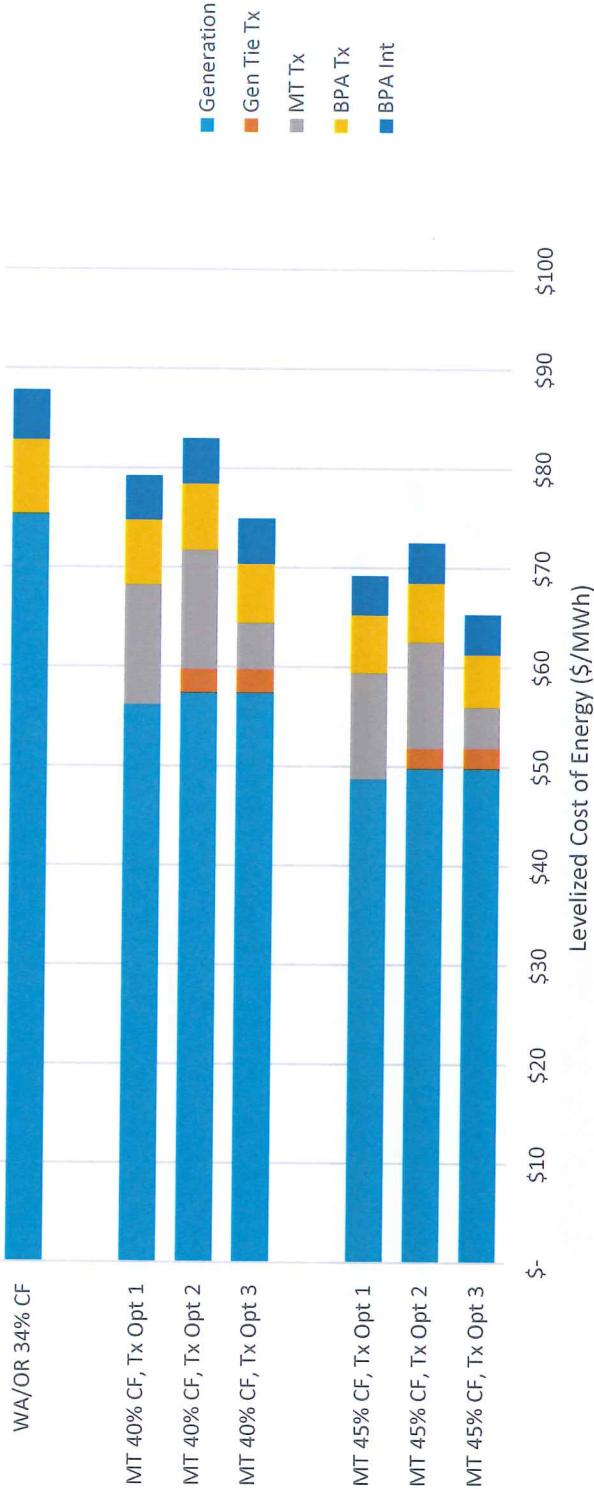
Chart 4

MT vs WA/OR Wind Comparison
Capacity Credit: WA/OR - 10%, MT - 50%
Full PTC
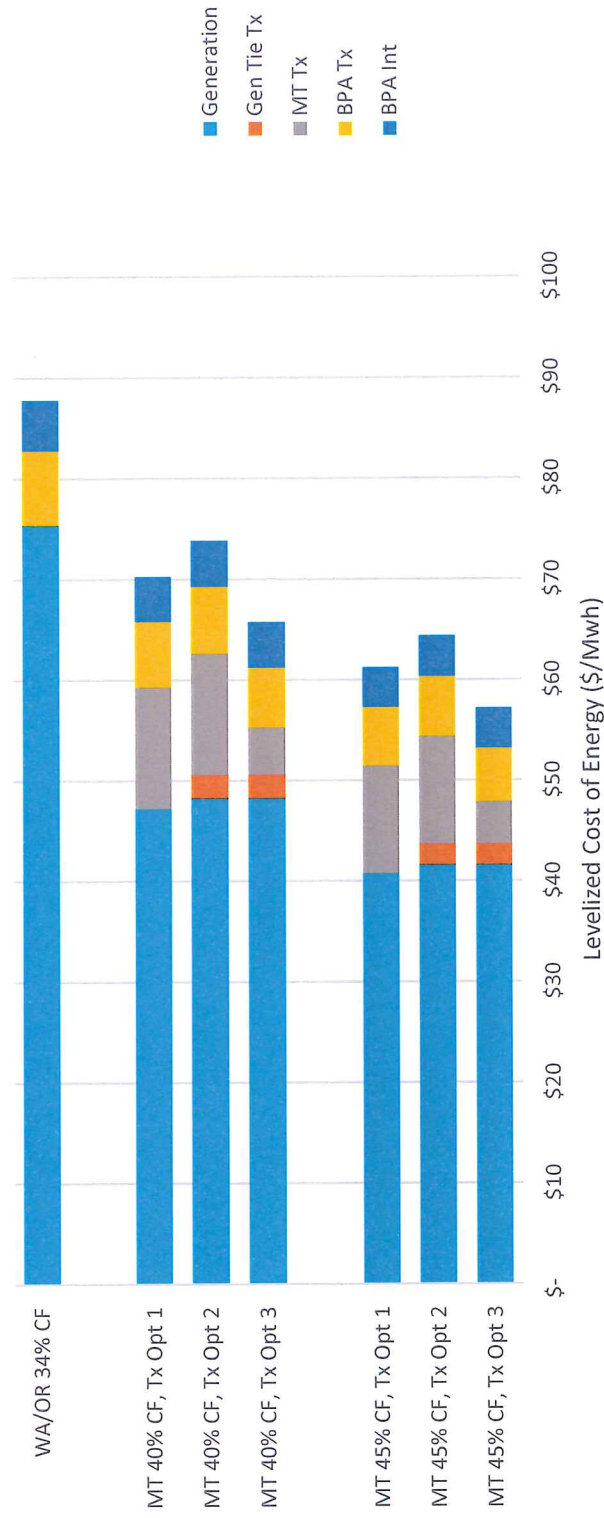
Chart 5

MT vs WA/OR Wind Comparison
Capacity Credit: WA/OR - None, MT - None
No PTC
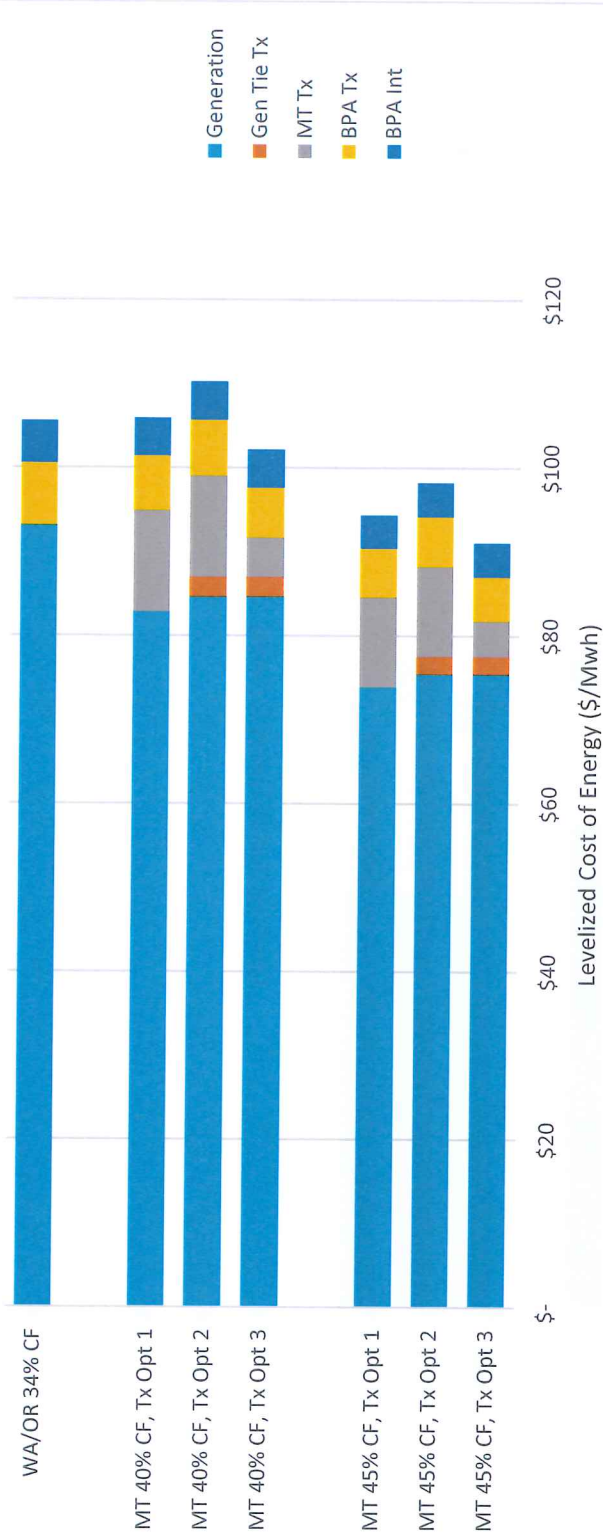
Chart 6

MT vs WA/OR Wind Comparison
Capacity Credit: WA/OR - 10%, MT - 10%
No PTC
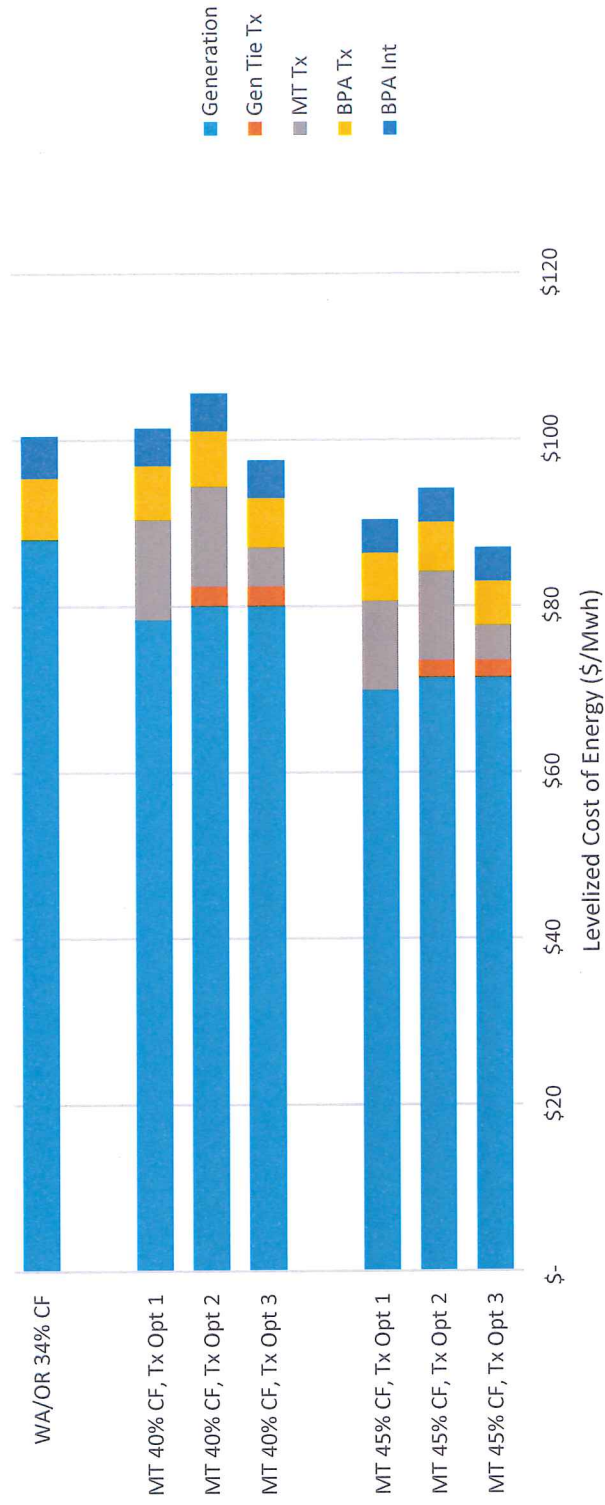
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Chart 7

MT vs WA/OR Wind Comparison
Capacity Credit: WA/OR - 10%, MT - 30%
No PTC

15

Chart 8

MT vs WA/OR Wind Comparison
Capacity Credit: WA/OR - 10%, MT - 50%
No PTC

Legend:
- Generation
- Gen Tie Tx
- MT Tx
- BPA Tx
- BPA Int

X-axis: Levelized Cost of Energy ($/Mwh) — $-, $20, $40, $60, $80, $100, $120

Categories:
- WA/OR 34% CF
- MT 40% CF, Tx Opt 1
- MT 40% CF, Tx Opt 2
- MT 40% CF, Tx Opt 3
- MT 45% CF, Tx Opt 1
- MT 45% CF, Tx Opt 2
- MT 45% CF, Tx Opt 3

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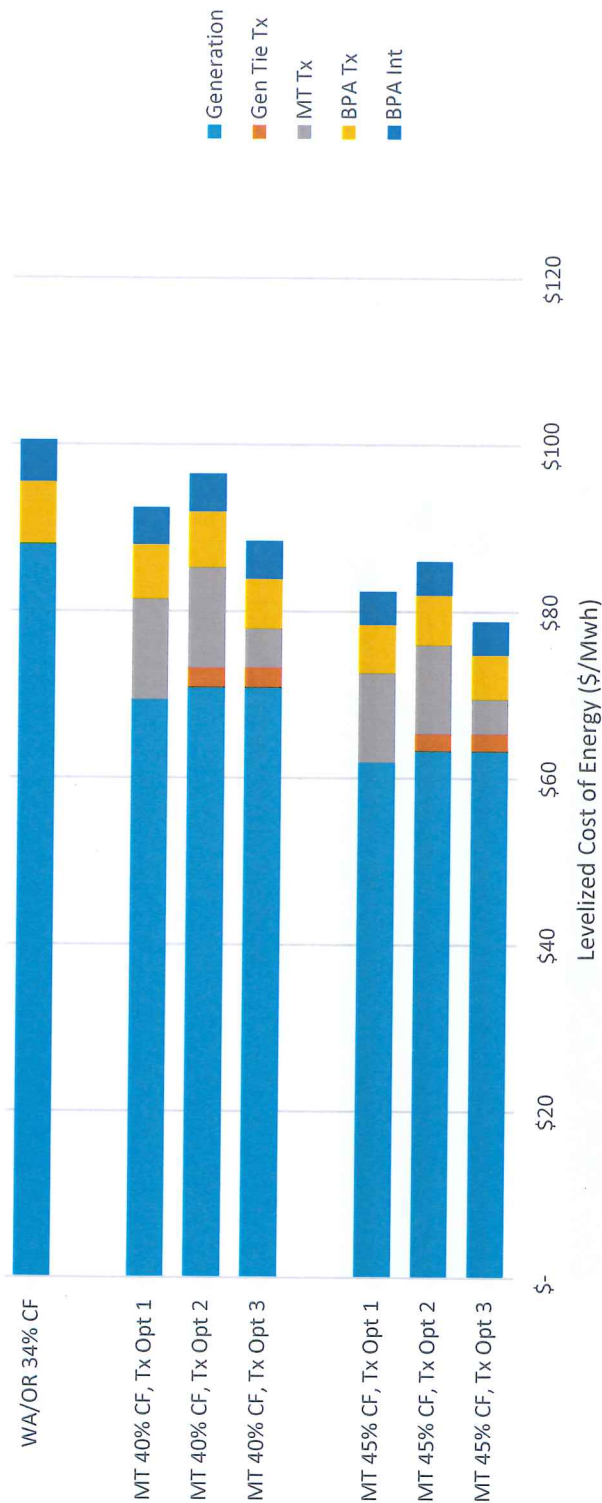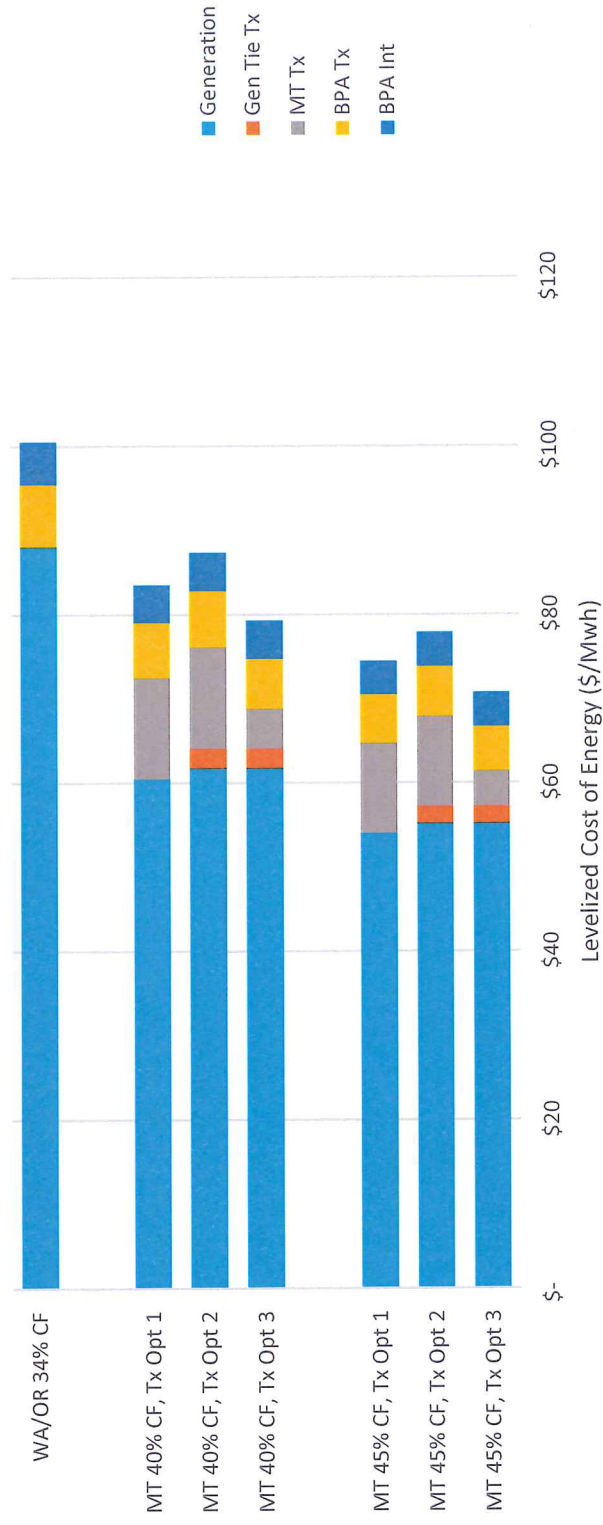
Henry Lorenzen
Chair
Oregon

Bill Bradbury
Oregon

Guy Norman
Washington

Tom Karier
Washington

W. Bill Booth
Vice Chair
Idaho

James Yost
Idaho

Jennifer Anders
Montana

Tim Baker
Montana

Northwest **Power** and
Conservation Council

April 4, 2017

MEMORANDUM

TO: **Council members**

FROM: **Brian Dekiep**

SUBJECT: **Transmission and Generation Resources in Montana**

BACKGROUND:

Presenters: John Leland, Consultant Northern Tier Transmission Group (NTTG), and former Northwestern Energy Transmission Planner.

Chelsea Loomis, Northwestern Energy Transmission Planner and NTTG Planning Committee Vice Chair.

Bill Pascoe: Pascoe Energy Consulting.

Brian Altman: Account Executive, Bonneville Power Administration.

Summary: This Power Committee item will have four presenters who are familiar with transmission and generation resources in Montana.

The Northern Tier Transmission Group (NTTG) is a group of transmission providers and customers that are actively involved in the sale and purchase of transmission capacity of the power grid that delivers electricity to customers in the Northwest and Mountain States. Transmission owners serving this region work in conjunction with state governments, customers,

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and other stakeholders to improve the operations of and chart the future for the grid that links all of these service territories. [1]

NTTG coordinates individual transmission systems operations, products, business practices, and planning of their high-voltage transmission network to meet and improve transmission services that deliver power to consumers. NTTG, in late December of 2016 released their draft redline 2016-2017 transmission plan. NTTG in coordination with Northwestern Energy has also conducted additional studies that look at the impacts to the regional transmission study with the potential closure of one or more plants at the Colstrip generation station in Montana.

Currently, Northwestern Energy has a significant amount of wind, solar and hydro resource activity in their generation interconnect transmission queue. Some of these Montana developers are also active in the BPA transmission planning process looking to export energy out of the state, while others are looking to provide energy to Montana's native load.

Bonneville Power is currently in their Transmission System Expansion Planning Process (TSEP). The TSEP is a process under which BPA Transmission (BPAT) responds to eligible requests for transmission service on its Network. In TSEP, BPAT processes and studies transmission service requests (TSRs) collectively unless a Customer requests an individual study for a specific TSR. TSEP consists of five phases: Pre-Study, the Cluster Study, Preliminary Engineering, Environmental Review, and Project Construction. The Cluster Study allows BPAT to aggregate TSRs to assess the collective system impacts and to identify the Plan(s) of Service to meet the demand.

Following a Cluster Study, if the Customer chooses to proceed with further evaluation of the Plan(s) of Service, BPAT will perform Preliminary Engineering and Environmental Review, as necessary. Based on the outcome of the study and review of the TSRs, and based on Customers' decisions whether to proceed, BPA will determine whether to proceed with the Plan(s) of Service to provide service. BPA recently providing notice that it is extending the date for completion of the 2016 Cluster Study until May 31, 2017. The Cluster study was proponed due to the overlapping commercial impacts of the cluster studies and the I-5 corridor reinforcement project. The BPA Administrator has not yet made a decision on this project. The I-5 Corridor Reinforcement Project is a proposed 500-kV transmission line between the areas near Castle Rock, Washington and Troutdale, Oregon.

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[1] https://nttg.biz/site/index.php?option=com_content&view=featured&Itemid=107

Biographical Information:

Bill Pascoe

Bill Pascoe is President of Pascoe Energy Consulting, a firm located in Absarokee, Montana and specializing in electricity supply and transmission issues. His clients include companies developing generation and transmission projects in Montana and surrounding states.

Mr. Pascoe was employed by The Montana Power Company and NorthWestern Energy for 25 years and served in key leadership positions including Vice President of Energy Supply and Sr. Vice President of Transmission.

Mr. Pascoe has been active in regional utility organizations and served terms as Chairman of the Pacific Northwest Utilities Conference Committee (PNUCC), Western Electricity Coordinating Council (WECC) and RTO West Board of Directors.

Mr. Pascoe is a Montana native and holds degrees in electrical and civil engineering from Montana State University.

John Leland

John Leland is a technical consultant for the Northern Tier Transmission Group ("NTTG") regional and interregional transmission planning processes. He retired from NorthWestern Energy in 2014 after 35 plus years of resource and transmission planning for the electric utility. John was a key player in the developing the policy and compliance responses to FERC Orders 890 and 1000 local, regional and interregional planning processes for NorthWestern Energy and NTTG.

He is an accomplished professional with successful experience in policy and regulatory compliance as well as analyzing and identifying solutions to complex technical problems.

Montana vs. Pacific Northwest Wind Cost Comparison

Prepared by:

Bill Pascoe, Pascoe Energy Consulting

December 2016

This report summarizes findings of an analysis that compares the cost of Montana wind and Pacific Northwest wind delivered to utilities in Washington and Oregon.

Background

For many years, Montana wind advocates have been touting the advantages of Montana wind to potential utility purchasers in Washington and Oregon. The primary advantages of Montana wind are:

- Higher capacity factors due to the more robust wind resource in Montana.
- Wind shapes that provide relatively more output during winter daytime hours when Pacific Northwest demand for electricity is highest.
- Diversity that reduces the cost of integrating additional wind energy into Pacific Northwest power systems.

These advantages have historically been offset by the cost and uncertainty of securing transmission service between Montana wind projects and utilities in Washington and Oregon. As described later in this report, reasonable transmission solutions are available.

Recent developments have increased interest in Montana wind by Washington and Oregon utilities that will create market opportunities in the near future. These developments include:

- An agreement reached by the owners of Colstrip 1&2 (Puget Sound Energy (PSE) and Talen Energy) and environmental groups that commits to the closure of Colstrip 1&2 no later than 2022. In addition to creating a need for power to replace 600 MW of retired baseload generation, this agreement frees up 300 MW of firm transmission rights between Colstrip and the PSE system.

- Enactment of the Oregon Clean Electricity and Coal Transition Plan (SB1547) in the 2016 Oregon legislative session that increases the renewable portfolio standard for Portland General Electric (PGE) to 50% by 2040. This requirement coupled with the recent phased-out extension of the federal production tax credit (PTC) has created an incentive for early action by PGE.

These developments have led PSE and PGE to give serious consideration to Montana wind in their recent Integrated Resource Plan (IRP) processes. This may lead to a once-in-a-decade opportunity for these utilities to acquire Montana wind resources.

Models, Data Sources and Assumptions

For this analysis, delivered costs were determined using the PowerFin levelized cost model maintained by the Northwest Power and Conservation Council (NPCC)[1]. As explained below, basic inputs to the model were taken from the NPCC's Seventh Power Plan with certain assumptions specified by the author.

Resource Costs

Capital and operating costs for wind generators ($2,240/kw CapEx) and aeroderivative CTs ($1,111/kw CapEx) were taken from the Seventh Power Plan.

The capital cost of wind generation has fallen since the Seventh Power Plan with costs in the range of $1,800 to $2,000/kw commonly cited. Using lower current costs for wind generation would lower the costs for both Montana wind and Pacific Northwest wind, but would not have a significant impact on the relative cost comparisons which are the focus of this analysis.

Wind costs were developed with and without federal PTCs. Assumptions about PTCs effect the costs for Montana wind and Pacific Northwest wind, but did not have a significant impact on the relative cost comparisons which are the focus of this analysis.

The cost of capacity from aeroderivative CTs is used to calculate the capacity value of the Montana wind and Pacific Northwest wind, as discussed further below.

Wind Capacity Factors

The capacity factor for Pacific Northwest wind was assumed to be 34%. This is the capacity factor used in PSE's 2015 IRP[2] and in PGE's 2016 IRP.

Two capacity factors were tested for Montana wind – 40% and 45%. These values were selected to represent a reasonable range for fair (40%) to good (45%) Montana wind sites and to evaluate the sensitivity of the results to this important parameter.

Wind Capacity Value

Capacity value is the capability of a wind farm to contribute toward a utility system's resource adequacy or effective load carrying capability. In simple terms, increased capacity value from wind generation reduces the need for a utility to develop conventional peaking resources. For this analysis, capacity value from wind resources was assumed to reduce capacity needed from new aeroderivative CTs which is a logical choice to provide new capacity with flexibility to complement wind and other intermittent resources.

The capacity value for Pacific Northwest wind was assumed to be 10%. This is similar to the values in PSE's 2015 IRP, PGE's 2016 IRP and a recent NPCC study[3].

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[1] NPCC staff provided the PowerFin results that are the foundation of this analysis.
[2] PSE's 2017 IRP will use a 37% capacity factor to reflect improved efficiency from newer wind turbine technology. A similar improvement in capacity factor would be expected from applying new technology to Montana wind sites.
[3] System Capacity Contribution of Montana Wind Resources, presented at August 9, 2016 NPCC meeting.

A range of capacity values for Montana wind – 10%, 30% and 50% - were tested in this analysis to evaluate the sensitivity of the results to this important parameter.

- 10% was selected as a lower bookend assuming Montana wind and Pacific Northwest wind have similar capacity values.
- 30% was selected as a midrange value and is similar to the value for the first 300 MW of Montana wind in PGE's 2016 IRP.
- 50% was selected as an upper bookend and is similar to the values found in PSE's 2015 IRP and the recent NPCC study[4].

Capacity value is treated as a credit against wind generation costs in this analysis.

Transmission

Securing affordable transmission is key to making the delivered cost of Montana wind competitive with Pacific Northwest wind. It is generally understood that Montana wind delivered over newly constructed long-distance transmission lines in Montana and/or on the BPA system is too expensive to compete with Pacific Northwest wind delivered over existing BPA transmission facilities. Fortunately, lower cost transmission alternatives exist for several hundred MW of Montana wind.

For this analysis, Pacific Northwest wind is assumed to be delivered over BPA's existing transmission facilities at the current BPA Main Grid rate ($21.48/kw-year).

For Montana wind, three transmission options were considered:

Option #1 – One wheel on the NorthWestern Energy (NWE) transmission system at current rates ($39.96/kw-year)[5] and one wheel on the BPA Main Grid ($21.48/kw-year)[6].

Option #2 – A generator tie line (at a cost of $80/kw)[7] interconnecting at Broadview or Colstrip followed by three wheels on transmission rights currently used to deliver PSE's share of Colstrip 1&2 – PSE Colstrip transmission ($31.82/kw-year), BPA Montana Intertie ($7.18/kw-year) and BPA Main Grid ($21.48/kw-year).

Option #3 - A generator tie line (at a cost of $80/kw)[8] interconnecting at Broadview followed by wheeling on upgraded facilities between Broadview and Garrison ($160/kw)[9] and on the BPA Main Grid ($300/kw)[10]. Note that using the financing assumptions in the NPCC levelized cost model, the annual costs of the upgrades are less

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[4] See footnote 3.

[5] Transmission service studies performed by NWE for Gaelectric indicate that approximately 330 MW of transmission capacity is available between the Harlowton, MT area and the BPA Main Grid with modest upgrades that would be rolled into NWE's current transmission rate.

[6] Recent conversations with BPA staff indicate that 200 MW of transmission is available for new Montana exports with the installation of a generator tripping scheme for certain contingencies.

[7] 70 miles of 230 kV wood H-frame transmission at $500,000/mile = $35 million, 450 MW capacity

[8] See footnote 7.

[9] $73 million in upgrades from Gaelectric transmission service study, 450 MW capacity

[10] $137 million in upgrades ($115 million from BPA 2010 NOS ROD escalated 3% per year), 450 MW capacity

than the current transmission rates used in Option #2. Under current FERC and BPA pricing policies these upgrades would be rolled into current rates and Montana wind exports would pay the same transmission costs as in Option #2.

Transmission losses were applied to each option based on current tariffs:

- Gen Tie – 3% (estimated)
- NWE – 4%
- PSE Colstrip / BPA MT Intertie – 3%
- BPA Main Grid – 1.9%

Integration Costs

BPA wind integration costs from the Seventh Power Plan ($14.76/kw-year) were included for all options.

Results

Results of the analysis are summarized in the following tables. In these tables, a positive value (blue shading) indicates the percentage by which the delivered cost for Montana wind exceeds Pacific Northwest wind. A negative value (green shading) indicates the percentage by which the delivered cost for Montana wind is less than Pacific Northwest wind.

Graphical depictions of the results for different assumptions for Montana wind capacity factors, Montana and Pacific Northwest wind capacity values, PTCs and transmission costs are provided in the Appendix.

Table 1A. MT Wind vs WA/OR Wind, Delivered Cost Comparison MT 40% CF, Full PTC

		Tx Option		
WA CV	MT CV	#1	#2	#3
0%	0%	0%	4%	-5%
10%	10%	0%	5%	-4%
10%	30%	-10%	-6%	-15%
10%	50%	-20%	-16%	-25%

Table 1B. MT Wind vs WA/OR Wind, Delivered Cost Comparison MT 40% CF, No PTC

		Tx Option		
WA CV	MT CV	#1	#2	#3
0%	0%	0%	4%	-3%
10%	10%	1%	5%	-3%
10%	30%	-8%	-4%	-12%
10%	50%	-17%	-13%	-21%

Table 2A. MT Wind vs WA/OR Wind, Delivered Cost Comparison MT 45% CF, Full PTC

WA CV	MT CV	Tx Option		
		#1	#2	#3
0%	0%	-13%	-9%	-17%
10%	10%	-12%	-8%	-16%
10%	30%	-21%	-17%	-26%
10%	50%	-30%	-27%	-35%

Table 2B. MT Wind vs WA/OR Wind, Delivered Cost Comparison MT 45% CF, Full PTC

WA CV	MT CV	Tx Option		
		#1	#2	#3
0%	0%	-11%	-7%	-14%
10%	10%	-10%	-6%	-13%
10%	30%	-18%	-14%	-22%
10%	50%	-26%	-23%	-30%

High level conclusions are as follows:

For Montana Wind with 40% CF and Full PTCs:

- Assuming no capacity value or 10% capacity value for Pacific Northwest wind and Montana wind, delivered costs for Montana wind range from 5% higher to 5% lower than Pacific Northwest wind depending on the transmission option selected.

- Assuming 10% capacity value for Pacific Northwest wind and 30% capacity value for Montana wind, delivered costs for Montana wind range from 6% to 15% lower than Pacific Northwest wind depending on the transmission option selected.

- Assuming 10% capacity value for Pacific Northwest wind and 50% capacity value for Montana wind, delivered costs for Montana wind range from 16% to 25% lower than Pacific Northwest wind depending on the transmission option selected.

For Montana Wind with 45% CF and Full PTCs:

- Assuming no capacity value or 10% capacity value for Pacific Northwest wind and Montana wind, delivered costs for Montana wind range from 8% to 17% lower than Pacific Northwest wind depending on the transmission option selected.

- Assuming 10% capacity value for Pacific Northwest wind and 30% capacity value for Montana wind, delivered costs for Montana wind range from 17% to 26% lower than Pacific Northwest wind depending on the transmission option selected.

- Assuming 10% capacity value for Pacific Northwest wind and 50% capacity value for Montana wind, delivered costs for Montana wind range from 27% to 35% lower than Pacific Northwest wind depending on the transmission option selected.

Assuming no PTCs, the cost advantage of Montana wind is reduced slightly (from 2% to 5%) depending on the particular case being considered.

These estimates of the cost advantage of Montana wind are conservative for the following reasons:

- This analysis calculates the capacity value difference between Pacific Northwest wind and Montana wind. However, it does not capture the difference in energy value from seasonal and diurnal shapes. Relatively more Montana wind is produced during the high-value winter season and relatively more Pacific Northwest wind is produced during the low-value spring season.

- This analysis assumes wind integration costs are the same for Pacific Northwest wind and Montana wind. However, due to diversity, Montana wind will be less costly to integrate into the Pacific Northwest system, especially for the first Montana wind to be integrated.

- This analysis assumes a relatively long (70 mile) generator tie line for Transmission Options #2 and #3. Montana wind projects located nearer to Broadview or Colstrip would reduce or eliminate the tie line costs and losses which make up about 5% to 6% of the total delivered costs. These costs would also be avoided if the Gordon Butte pumped hydro project is successfully developed and the very high quality wind resources in that area access the Colstrip transmission lines through the Gordon Butte interconnection.

- Transmission Option #2 includes transmission rates for PSE Colstrip transmission and the BPA Montana Intertie. Closure of Colstrip 1&2 will free up 300 MW of transmission capacity on these facilities. The cost of this capacity will continue to be borne by PSE ratepayers unless this capacity is used for some other purpose such as delivering Montana wind. Treating these as sunk costs reduces total delivered costs for Montana wind by between 11% and 17%.

APPENDIX

Chart 1. PNW Capacity Value – 0%, MT Capacity Value – 0%, Full PTCs

Chart 2. PNW Capacity Value – 10%, MT Capacity Value – 10%, Full PTCs

Chart 3. PNW Capacity Value – 10%, MT Capacity Value – 30%, Full PTCs

Chart 4. PNW Capacity Value – 10%, MT Capacity Value – 50%, Full PTCs

Chart 5. PNW Capacity Value – 0%, MT Capacity Value – 0%, No PTCs

Chart 6. PNW Capacity Value – 10%, MT Capacity Value – 10%, No PTCs

Chart 7. PNW Capacity Value – 10%, MT Capacity Value – 30%, No PTCs

Chart 8. PNW Capacity Value – 10%, MT Capacity Value – 50%, No PTCs

Chart 1

MT vs WA/OR Wind Comparison
Capacity Credit: WA/OR - None, MT - None
Full PTC

Chart 2

MT vs WA/OR Wind Comparison
Capacity Credit: WA/OR - 10%, MT - 10%
Full PTC

Legend: Generation, Gen Tie Tx, MT Tx, BPA Tx, BPA Int

X-axis: Levelized Cost of Energy ($/Mwh) — $-, $10, $20, $30, $40, $50, $60, $70, $80, $90, $100

Categories: WA/OR 34% CF; MT 40% CF, Tx Opt 1; MT 40% CF, Tx Opt 2; MT 40% CF, Tx Opt 3; MT 45% CF, Tx Opt 1; MT 45% CF, Tx Opt 2; MT 45% CF, Tx Opt 3

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Chart 3

MT vs WA/OR Wind Comparison
Capacity Credit: WA/OR - 10%, MT - 30%
Full PTC

Chart 4

MT vs WA/OR Wind Comparison
Capacity Credit: WA/OR - 10%, MT - 50%
Full PTC

Legend:
- Generation
- Gen Tie Tx
- MT Tx
- BPA Tx
- BPA Int

X-axis: Levelized Cost of Energy ($/Mwh)

Categories:
- WA/OR 34% CF
- MT 40% CF, Tx Opt 1
- MT 40% CF, Tx Opt 2
- MT 40% CF, Tx Opt 3
- MT 45% CF, Tx Opt 1
- MT 45% CF, Tx Opt 2
- MT 45% CF, Tx Opt 3

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Chart 5

MT vs WA/OR Wind Comparison
Capacity Credit: WA/OR - None, MT - None
No PTC

Legend:
- Generation
- Gen Tie Tx
- MT Tx
- BPA Tx
- BPA Int

Categories:
- WA/OR 34% CF
- MT 40% CF, Tx Opt 1
- MT 40% CF, Tx Opt 2
- MT 40% CF, Tx Opt 3
- MT 45% CF, Tx Opt 1
- MT 45% CF, Tx Opt 2
- MT 45% CF, Tx Opt 3

X-axis: Levelized Cost of Energy ($/Mwh) — $-, $20, $40, $60, $80, $100, $120

Chart 6

MT vs WA/OR Wind Comparison
Capacity Credit: WA/OR - 10%, MT - 10%
No PTC

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Chart 7

MT vs WA/OR Wind Comparison
Capacity Credit: WA/OR - 10%, MT - 30%
No PTC

Chart 8

MT vs WA/OR Wind Comparison
Capacity Credit: WA/OR - 10%, MT - 50%
No PTC

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Energy+Environmental Economics

Gordon Butte Pumped Storage

Colstrip 1&2 Replacement Analysis

Prepared by E3 for Absaroka Energy

December 2016

Analysis Overview

+ Absaroka Energy asked E3 to compare the cost of two alternatives for providing energy (250 aMW) and capacity (300 MW) to replace Puget Sound Energy's share of Colstrip 1&2

- **MT Alternative:** Gordon Butte Pumped Storage facility paired with 250 aMW of Montana wind (located at Martinsdale, MT) and 300 MW of existing long-term firm transmission rights from Montana to PSE

- **PNW Alternative:** An Aeroderivative CT generator (located in Washington state) paired with 250 aMW of Washington wind (located at the Columbia Gorge)

Gordon Butte Overview

✛ Gordon Butte Pumped Storage Facility

- 400 MW pumping / generating capacity

- Ternary units allow seamless transition between generating and pumping modes

- 8.5 available hours of storage

- 83% efficiency

- Sited to allow access to transmission currently used to deliver power from Colstrip coal plants in Montana. Some of this transmission capacity will become available when Colstrip 1&2 are retired (no later than 2022).

- FERC License issued December 14, 2016.

Analysis Scope

+ Quantified benefits of pumped storage

- Shaping of wind resource to maximize value, avoid curtailment, and increase transmission utilization

- Ability to provide firm capacity on demand (given available capacity)

- Emissions-free flexible resource helps with wind integration

- Time-based market arbitrage opportunities (given available capacity)

+ Potential benefits of pumped storage not considered here

- Ability to provide ancillary services (Load-following, Regulation, Spinning & Non-Spinning Reserves, Frequency Response)

- Sub-hourly energy dispatch savings

- Value derived from participation in the Energy Imbalance Market

MT Alternative

Washington

Montana

Year = 2030

250 aMW Montana,
CF ~46%

Dispatch value of energy provided to Puget Sound is determined by market prices at Mid-C

Mid-C Market

Puget Sound Energy

MT Sales

Gordon Butte Pumped Storage Facility

300 MW
(1.5% Losses)

PNW Alternative

Year = 2030

Washington
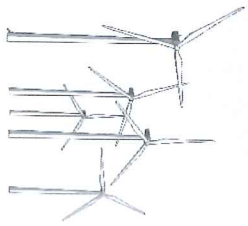
Montana

250 aMW Columbia Gorge, CF ~34%
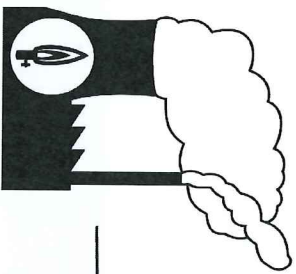
Aero CT Gas Plant

Mid-C Market

Puget Sound Energy

300 MW (1.5% Losses)

Dispatch value of energy provided to Puget Sound is determined by market prices at Mid-C

MT Sales

Wind Capacity Credit

+ Absaroka also asked E3 to investigate how geography-based differences in Effective Load Carrying Capability (ELCC) between wind sites might influence the results of the analysis

• To achieve this, E3 sized both the pumped storage and Aero CT resources so that they provide 300 MW of capacity when paired with the planning capacity assigned to wind resources

Assumption	WA Wind – Installed Capacity	WA Wind – Planning Capacity	Aero CT Size	MT Wind – Installed Capacity	MT Wind – Credited Capacity	Pumped Storage Size
No Capacity Credit for Wind	736 MW	0 MW	300 MW	548 MW	0 MW	300 MW
Capacity Credit for Wind	736 MW	37 MW (5%)	263 MW	548 MW	137 MW (25%)	163 MW

Modeling Efforts

+ **Fixed costs for the resources were calculated using E3 financial models and publicly available data sources**

+ **Hourly dispatch values were calculated using an adapted version of the E3 REFLEX model**

  - REFLEX is a multi-stage production simulation model with integer variables formulated for high renewable penetrations

  - Hourly modeling of energy values and arbitrage opportunities

  - Hourly generation profiles for non-dispatchable (wind) generation

  - Priced-based dispatch of controllable resources

  - 24-hour optimization of storage resources

Data Sources – Wind Resource Characteristics

+ **Wind shapes provided by Absaroka Energy**

  - E3 adjusted to reflect most recent capacity factors

    - Washington (Columbia Gorge): 34% Capacity Factor
    - Montana (Martinsdale, MT): 46% Capacity Factor

  - Nameplate capacity sized to output 250 aMW over the course of the year

    - Columbia Gorge: 736 MW
    - Martinsdale: 548 MW

+ **Wind planning capacity based on location of wind resources**

  - Reasonable estimates based on previous E3 analysis

    - Washington (Columbia Gorge): 5% Capacity Value
    - Montana (Martinsdale, MT): 25% Capacity Value

Data Sources – Other Resource Characteristics

- **Aero CT characteristics based on generators in the TEPPC Common Case**

- **Pumped storage operational characteristics provided by Absaroka Energy** (see previous slide)

- **Transmission losses of 1.5% Montana to BPA**
  - Based on Colstrip Transmission System losses from Broadview to Garrison

Renewable Northwest

Executive Summary of
Energy Strategies LLC

Assessment of the Cost Competitiveness of Montana Wind Energy for Washington Markets

September 2016

Image: Mark Plummer, via Flickr Creative Commons license

Renewable
Northwest

The energy landscape is shifting dramatically in the United States, and nowhere is this more apparent than in the market comprising the Pacific Northwest and the Northern Rockies. Here, in the region spanning Washington to Montana, dramatically changing consumer preferences, energy economics, new policies, aging infrastructure and more protective regulatory safeguards are all combining to reshape a system that has supplied power to the region for much of the past four decades.

The rise of wind power is one of the fundamental changes taking place in this transformation to a new energy paradigm, and Washington is in a prime position to benefit. Findings from this analysis by Energy Strategies LLC demonstrate the state's opportunity to take advantage of Montana's wind energy and its inherent cost-competitiveness.

If Washington's leaders can plan accordingly, it will allow them to take advantage of existing infrastructure and make an effective ecomomic transition from the old system, which was built decades ago around coal as a baseload source of electricity generation, to the new one, which is less centralized and more dynamic. With Montana wind output aligning closely with Pacific Northwest demand, Washington, and in particular Puget Sound Energy, are in a position to capitalize on the reality of the new energy era.

The Study

Energy Strategies LLC, an independent energy consulting firm that works frequently with large commercial, industrial and public sector energy users and energy project developers, set out to assess the relative costs of generating and delivering wind energy in Montana, Oregon and Washington into Puget Sound Energy's system. The study, which was commissioned by the Western Clean Energy Campaign, started with the identification of potential wind energy sites in each of the three states.

Using tools developed by the National Renewable Energy Laboratory, a total of nine potential sites were identified as strong candidates for wind projects: five in Montana, and two each in Oregon and Washington. The nine sites shared characteristics that included proximity to clusters of wind resource and relatively similar distances from existing transmission infrastructure, as well as having enough capacity to meet PSE demand. For each site, Energy Strategies analyzed hourly generation characteristics, looking in particular at average peak winter and summer capacity factors. This data was combined with projected delivery costs in order to determine the levelized cost of electricity, thereby allowing an apples-to-apples comparison between the sites.

The Findings

Results from the comparative modeling indicate that developing wind power in Montana may be advantageous for Puget Sound Energy. Overall, the study found that the wind resources profiled in Montana are generally more plentiful and of higher quality than those in Washington and Oregon. While the sites in all three states have roughly comparable summer capacity factors, the Montana wind sites have consistently and substantially higher winter capacity factors. These characteristics combine to make Montana's wind a potentially valuable generation resource for PSE for several important reasons:

- There is close alignment between PSE's demand characteristics and the energy profile of the five potential wind sites studied in Montana. PSE is a winter-peaking electric utility, with maximum load demands placed on its system during late morning and early evening hours in the winter months, precisely when the wind at the sites assessed in Montana is strongest and most consistent. In other

Average Capacity Factors by Transmission Region; Jan & Jul 2012

	Region	Average	January	July
MT	1	45.0%	63.8%	23.5%
	2	39.9%	66.7%	16.3%
	3	40.0%	49.7%	22.5%
	Average	42.0%	64.8%	21.7%
WA	4	35.7%	45.3%	30.2%
OR	5	38.8%	45.1%	39.3%

Energy Strategies LLC

words, Montana wind produces the most energy at the time when PSE needs it most.

- The higher capacity factors for Montana wind help overcome higher relative transmission costs of moving electricity substantially longer distances.
- Even when energy losses from transmitting electricity 1,000 miles to PSE's service territory are factored in, Montana wind is still competitive with wind resources in Washington and Oregon.
- PSE and its co-owner in the Colstrip coal-fired power plant in Montana, Talen Energy, recently announced the retirement of their joint share of the two oldest units at the plant (totaling 716 megawatts) by July 2022, and likely sooner given the poor economics of continuing to operate them. A phase-out of the Colstrip units will open up current bottlenecks in available transmission capacity that connect into PSE's' service territory. This freed-up capacity will facilitate continued use of the existing lines.

Conclusion

As Puget Sound Energy considers its options for adding new electric generating capacity and replacing the output of its ownership share in the Colstrip plant, Energy Strategies' analysis demonstrates that developing new wind resources in Montana appears on balance to be a viable, cost-competitive alternative to adding new wind resources from either Oregon or Washington. Despite the additional costs incurred in transmitting Montana wind significantly farther distances, the Montana sites share the advantage of having wind profiles that align well with PSE's peak season (winter) demands, which makes the sites more valuable than a simple cost comparison would indicate.

Montana wind has additional advantages, as well. First, adding Montana wind to PSE's portfolio of current Washington wind resources would provide resource diversity and security and increase the resilience of the system. Second, because a larger share of wind costs in Montana consist of transmission, any reduction in the costs of connecting to the grid improve the competitiveness even further. The announcemnt of Colstrip's retirement, for example, will soon make significant transmission capacity available, allowing Montana wind projects to interconnect with PSE's transmission more directly, which could sidestep some current transmission tariffs.

In light of Puget Sound Energy's July 2016 announcement of its intention to retire Colstrip units 1 and 2, the company is already mapping out its options for the future generation resources as possible replacement alternatives. Given the advantages of Montana wind surfaced by the Energy Strategies analysis, it would be prudent for decision-makers in both Washington and Montana to think about new wind projects in the Big Sky State. The phase-out of Colstrip presents an opportunity to capitalize on an existing infrastructure and a long, cooperative history between Montana and Washington of doing business together on energy.

Puget Sound Energy's transmission system
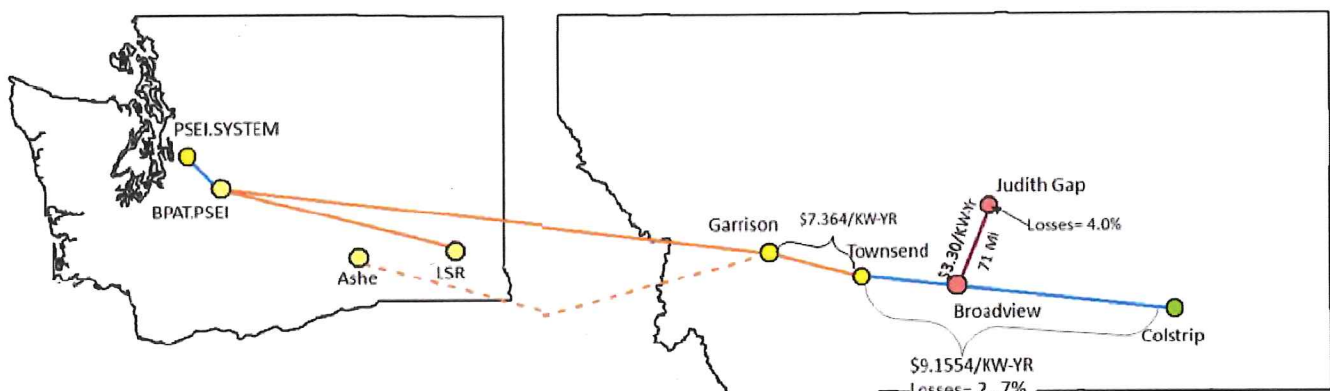
Source: Puget Sound Energy

Assessment Of The Cost Competitiveness of Montana Wind Energy

A Webinar From

Renewable Northwest

Conducted By

Energy Strategies LLC

September 14, 2016

Revised From July 27, 2016

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Project Purpose

To develop an independent assessment of the relative costs to produce and deliver wind energy generated in Montana, Oregon, and Washington to Puget Sound Energy's system

Site Selection

Selected Wind Locations in Each State

Montana	Oregon	Washington
Region 1	**Region 4**	**Region 5**
MT "A" Helena - Great Falls	OR "A" Dalles - Hermiston	WA "A" Vantage
MT "B" Stanford - Fort Benton	OR "B" LaGrande - Baker	WA "B" West of Lewiston
Region 2		
MT "C" Harlowton		
Region 3		
MT "D" Livingston – Big Timber		
MT "E" Near Colstrip		

For purposes of transmission cost estimation, locations with relatively close proximity were grouped into these five transmission "regions"

Montana Wind Resource & Site Locations

Region 1

MT_A Helena to Great Falls

MT_B Stanford to Fort Benton

Montana

Region 2

MT_C Harlowton

MT_D Livingston to Big Timber

89

90

87

12

Region 3

MT_E Colstrip

Wind Power Classification

Wind Power Class	Resource Potential	Wind Power Density at 50 m W/m²	Wind Speed [a] at 50 m m/s	Wind Speed [a] at 50 m mph
3	Fair	300 - 400	6.4 - 7.0	14.3 - 15.7
4	Good	400 - 500	7.0 - 7.5	15.7 - 16.8
5	Excellent	500 - 600	7.5 - 8.0	16.8 - 17.9
6	Outstanding	600 - 800	8.0 - 8.8	17.9 - 19.7
7	Superb	800 - 1600	8.8 - 11.1	19.7 - 24.8

[a] Wind speeds are based on a Weibull k value of 2.0

Northwestern Transmission System
PSEI Transmission (Colstrip to Broadview to Townsend)
Townsend to Garrison
BPA Transmission

Washington and Oregon
Wind Resource & Site Locations
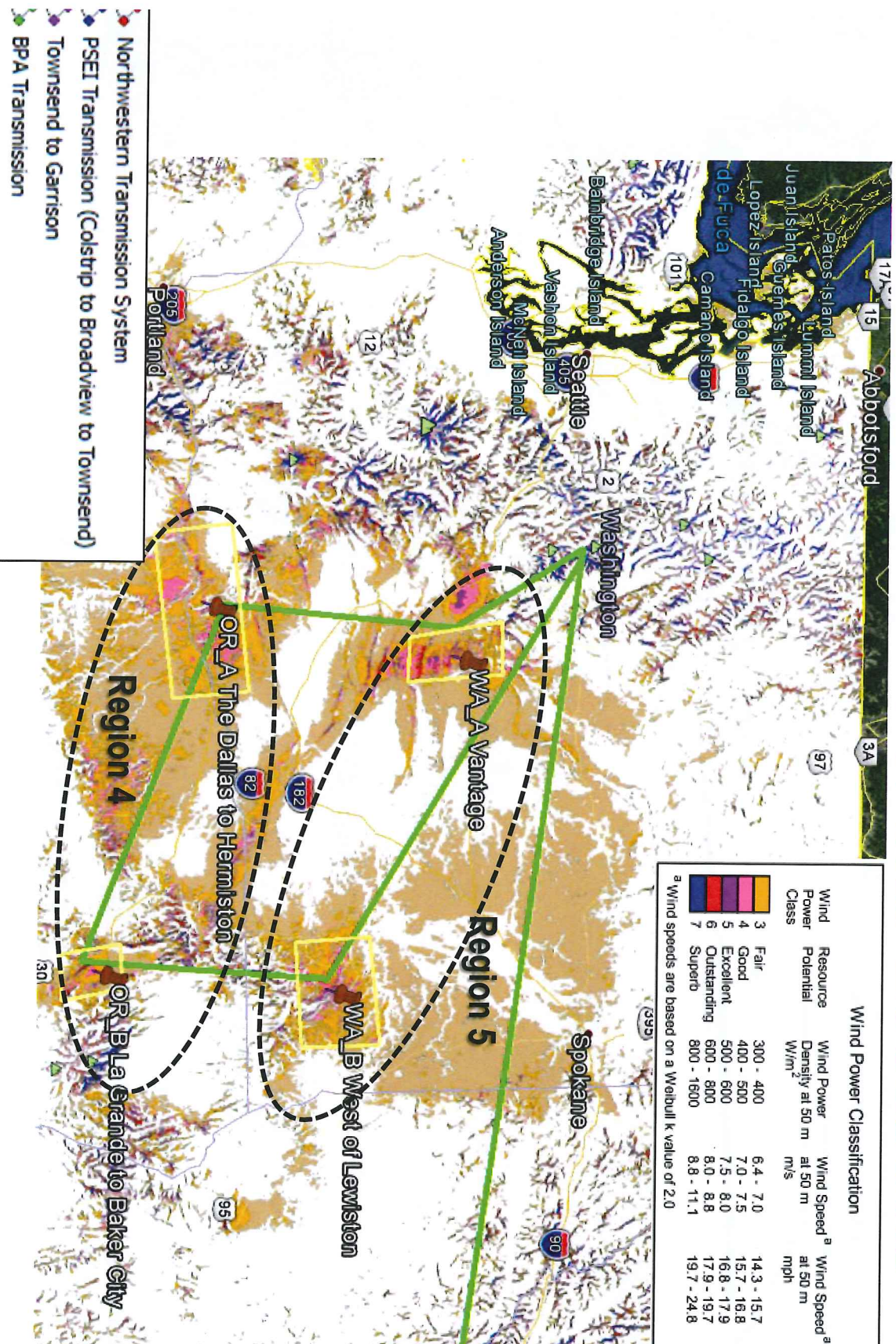
Wind Location Hourly Profiles

Energy Strategies LLC

Average Capacity Factors by Transmission Region; Jan & July 2012

	Region	Average	Average January	July
MT	1	45.0%	63.8%	23.5%
	2	39.9%	66.7%	16.3%
	3	40.0%	49.7%	22.5%
	Average	42.0%	64.8%	21.7%
OR	4	38.8%	45.1%	39.3%
WA	5	35.7%	45.3%	30.2%

January 2012
Average Hourly Capacity Factors

	Averages
MT	64.8%
WA	45.1%
OR	45.3%

Legend: MT_A, MT_B, MT_C, MT_D, MT_E, OR_A, OR_B, WA_A, WA_B

Peak Demand Hours
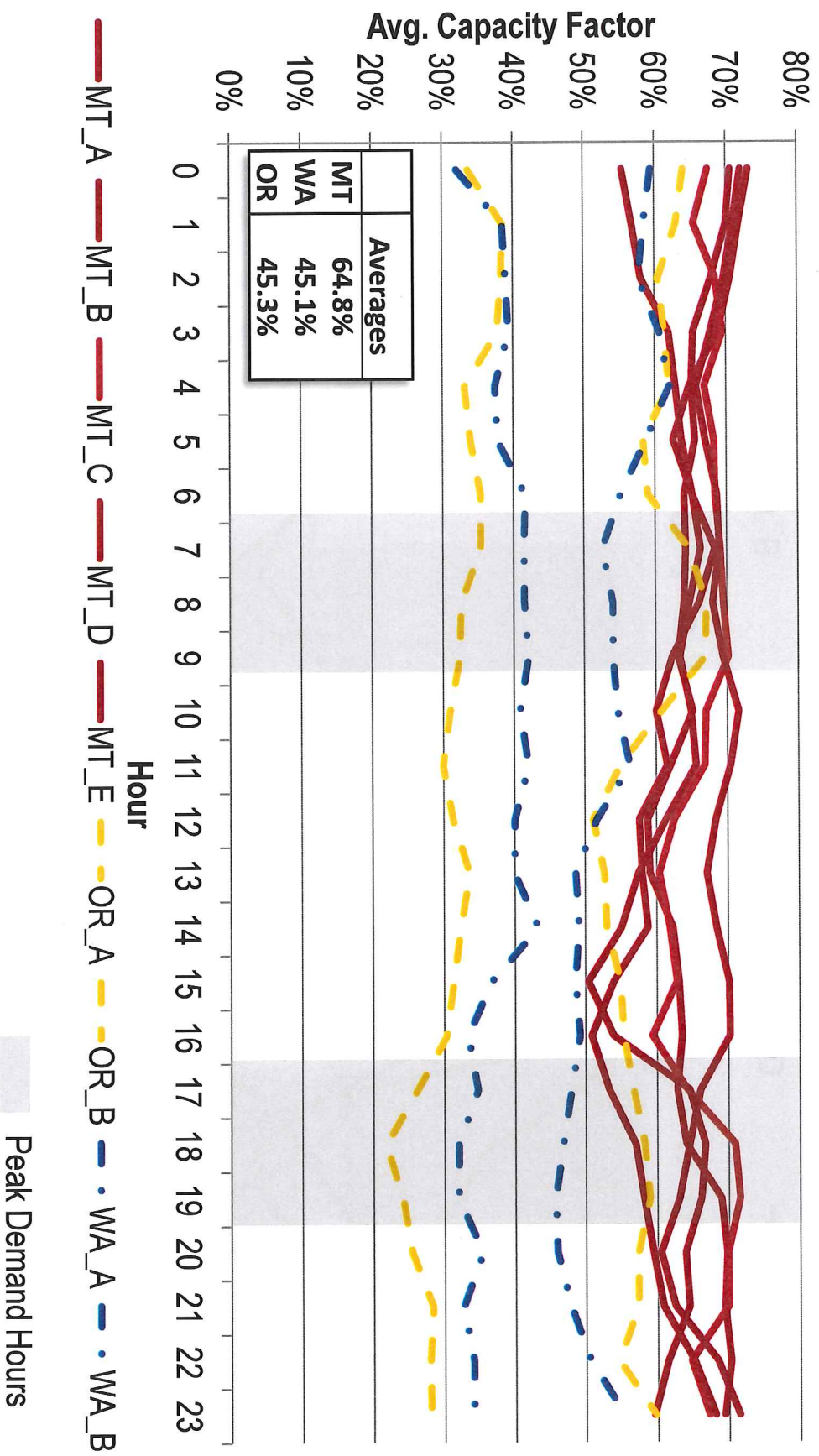
January 2012 Montana
Average Hourly Capacity Factors

Avg. Capacity Factor

MT_A
MT_B
MT_C
MT_D
MT_E

Peak Demand Hours

Energy Strategies LLC

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July 2012
Average Hourly Capacity Factors

		Averages
MT		21.7%
WA		30.2%
OR		39.3%

Legend: MT_A, MT_B, MT_C, MT_D, MT_E, OR_A, OR_B, WA_A, WA_B

Peak Demand Hours

Energy Strategies LLC

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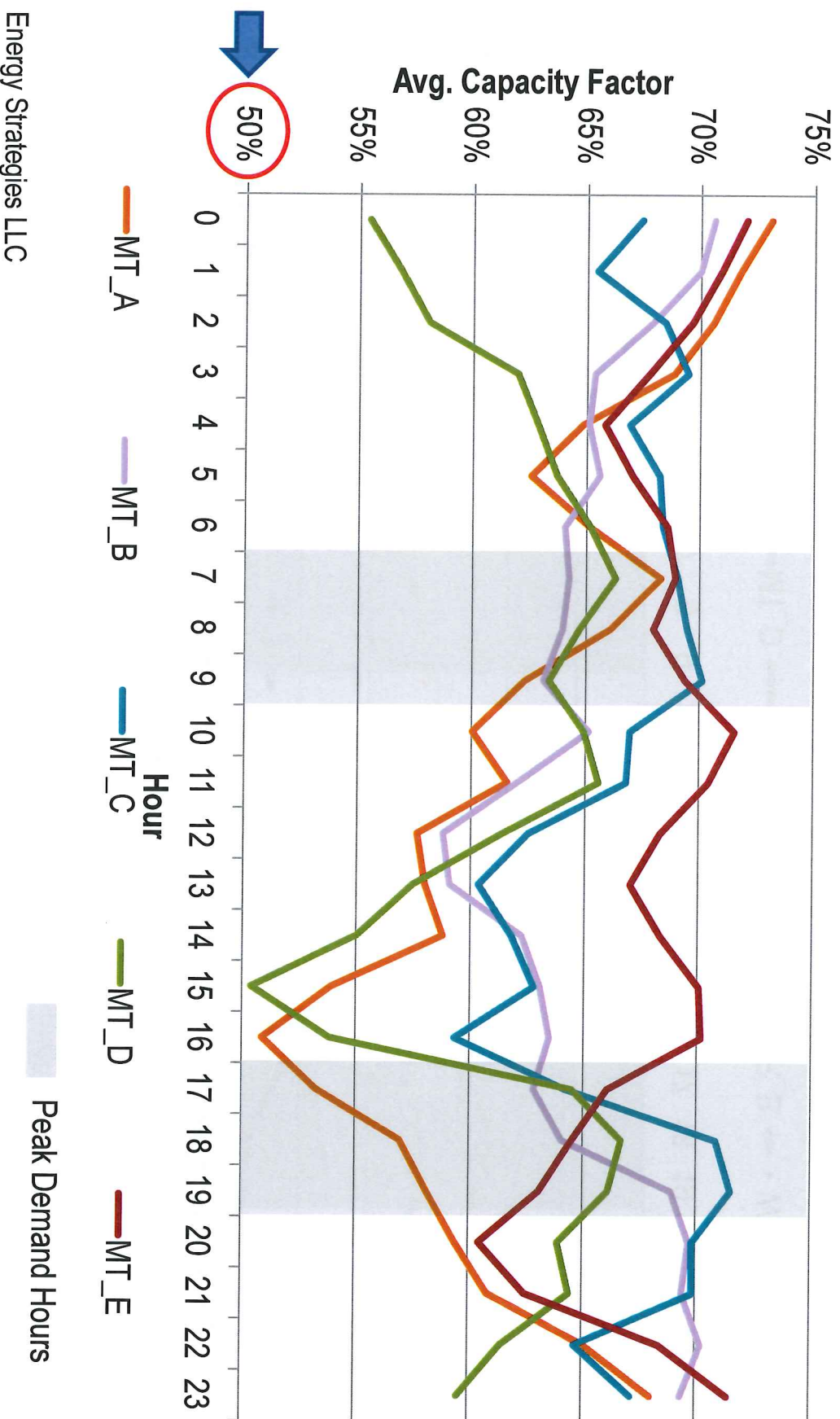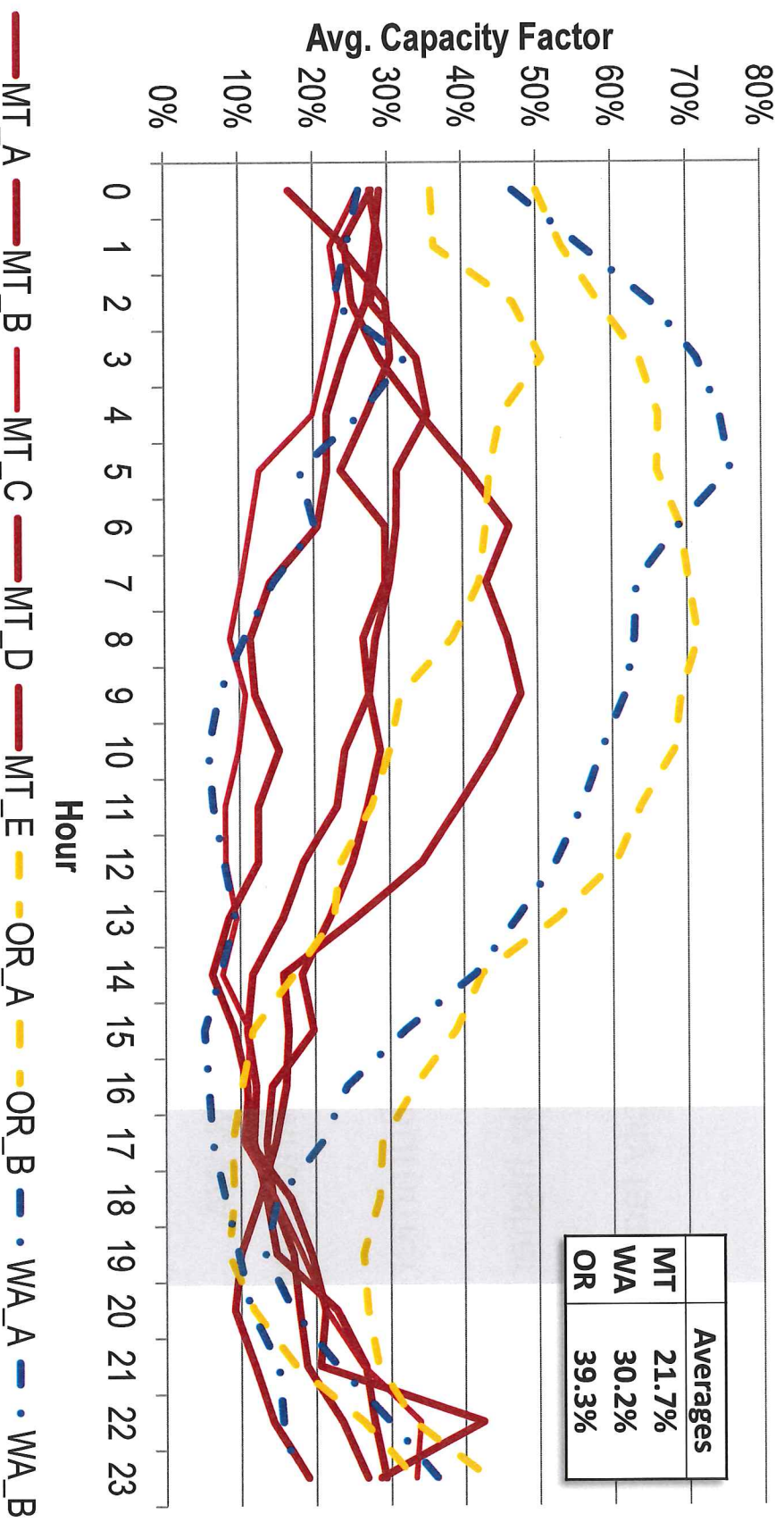
Observations

- PSE is a winter-peaking electric utility whose peak load matches well with Montana wind sites' production profiles

- The NREL visualization tool, and the underlying data, indicate that across the three states, generally:

  – MT has substantially more wind resource than OR & WA

  – MT wind is higher quality on the basis of potential wind generation capacity factor

- For the average hourly 2012 Winter (January) & Summer (July) capacity factors for each wind site

  – Montana wind sites have consistently & substantially higher Winter capacity factors than the four OR & WA sites

  – One OR & one WA site have higher Summer capacity factors than the highest capacity factor Montana site

Estimated Delivery Costs

Estimated Delivery Cost

- Refers to transmission-related fees charged by each Transmission Provider (TP) across whose system the identified wind resource would pass in route to PSE

- Delivery costs were applied based on current rates in each TP's FERC-approved Open Access Transmission Tariff (OATT), and in dialog with the TPs and experienced Montana wind developers

- Transmission losses were assumed to be self-supplied

- The study did not include estimated interconnection costs

- The study assumes BPA will provide all necessary operating reserves and wind balancing services

Open Access Transmission Tariff Rates

Service	NorthWestern		Bonneville Power Administration					
	Point to Point		Point to Point		Montana Intertie Townsend to Garrison		PSE Colstrip Line Colstrip to Townsend	
	Fixed Cost ($/KW-yr)	Variable Cost ($/MWh)	Fixed Cost ($/KW-yr)	Variable Cost ($/MWh)	Fixed Cost ($/KW-yr)	Variable Cost ($/MWh)	Fixed Cost ($/KW-yr)	Variable Cost ($/MWh)
Yearly firm point-to-point	$37.92		$17.87		$7.18		$31.83	
Scheduling, system control & dispatch	$2.00		$3.61		$3.61			
Reactive supply & voltage control								
Regulation & frequency response								
Energy imbalance service		Various		Various				
Operating reserves: Spinning*				$0.34				
Operating reserves: Supplemental*				$0.31				
Wind balancing schedules								
Regulating Reserves				$0.96				
Following Reserves				$3.84				
Imbalance reserves				$3.96				
Opt out fee				$0.24				
Totals	$39.92	$0.00	$30.48	$0.66	$10.79		$31.83	
Transmission losses	4%		1.9%		5%		2.7%	

* Applied according to BPA's published Billing Factors for Operating Reserves

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Transmission Costs by
Site & Region Applied in Cost Modeling

Study Region	Project ID	Transmission Losses Applied	Total Fixed Cost ($/KW-yr)	Total Variable Cost ($/MWh)
1	MT – A	5.9%	$70.40	$0.66
1	MT – B	5.9%	$70.40	$0.66
2	MT – C	4.6%	$73.10	$0.66
3	MT – D	4.6%	$73.10	$0.66
3	MT – E	4.6%	$73.10	$0.66
4/5	WA – A	1.9%	$30.48	$0.66
4/5	WA – B	1.9%	$30.48	$0.66
4/5	OR – A	1.9%	$30.48	$0.66
4/5	OR – B	1.9%	$30.48	$0.66
No MT Intertie Costs	2	MT – C	4.6%	$62.31	$0.66
No MT Intertie Costs	3	MT – D	4.6%	$62.31	$0.66
No MT Intertie Costs		MT – E	4.6%	$62.31	$0.66

Rate application is based on the following assumptions:
Montana regions 2 & 3 and 4 & 5 have the same transmission costs. Projects in MT regions 2 & 3 build generator interconnection lines to the Colstrip Line. Projects will use PSE's Colstrip Line ownership, thereby incurring the PSE Colstrip Line loss of 2.7%, not the MT Intertie loss of 5%. Projects will pay fixed transmission costs for both PSE's Colstrip Line and BPA 's Montana Intertie.

Levelized Cost of Energy (LCOE) Comparisons

LCOE: Tools & Assumptions

- LCOE for each site was calculated using the WECC TEPPC cost calculator
  - Modified for losses, fixed and variable costs over a 20-year term
- Assumed a 265 MW project at each site*
- Assumed wind projects at each site reach COD in 2020
- Projects do not receive production tax credit (PTC)
- Capital costs for all projects was set at $1,703/kW*
- Projects in WA included additional $123/kW sales tax*
- Generation interconnection costs were not modeled
- LCOE run for independent power producer (IPP) financing scenarios

*Aligns with the value used by PSE in their 2015 IRP

LCOE Comparison by Wind Site
IPP Financing

LCOE ($/MWH)

Lowest LCOE

MT_A, MT_B, MT_C, MT_D, MT_E, OR_A, OR_B, WA_A, WA_B

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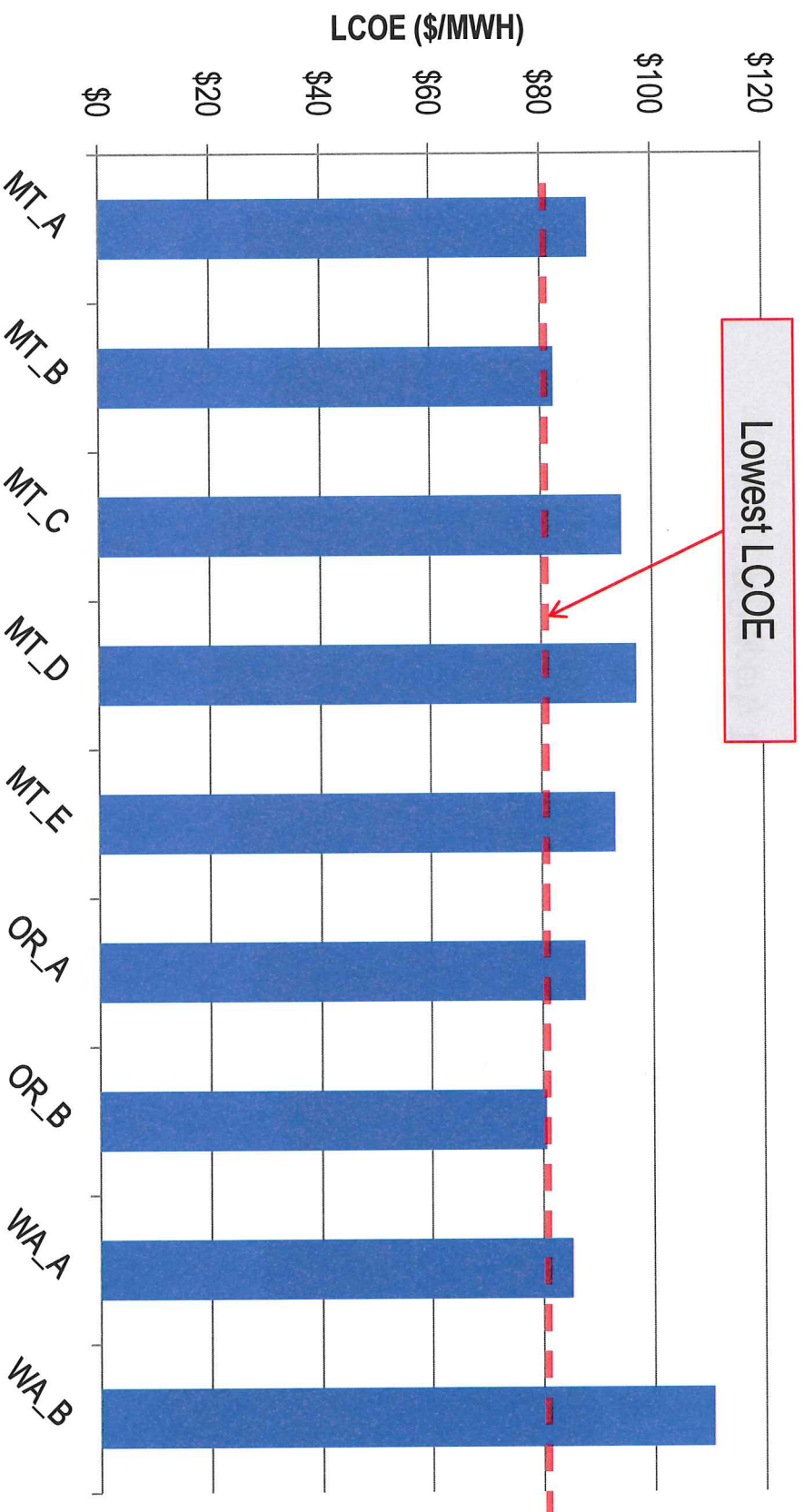
LCOE by Cost Component
IPP Financing

Lowest LCOE

LCOE ($/MWH)

Capital
Variable O&M
Property Tax & Insurance
Fixed Transmission
Fixed O&M
Variable Transmission

MT_A, MT_B, MT_C, MT_D, MT_E, OR_A, OR_B, WA_A, WA_B

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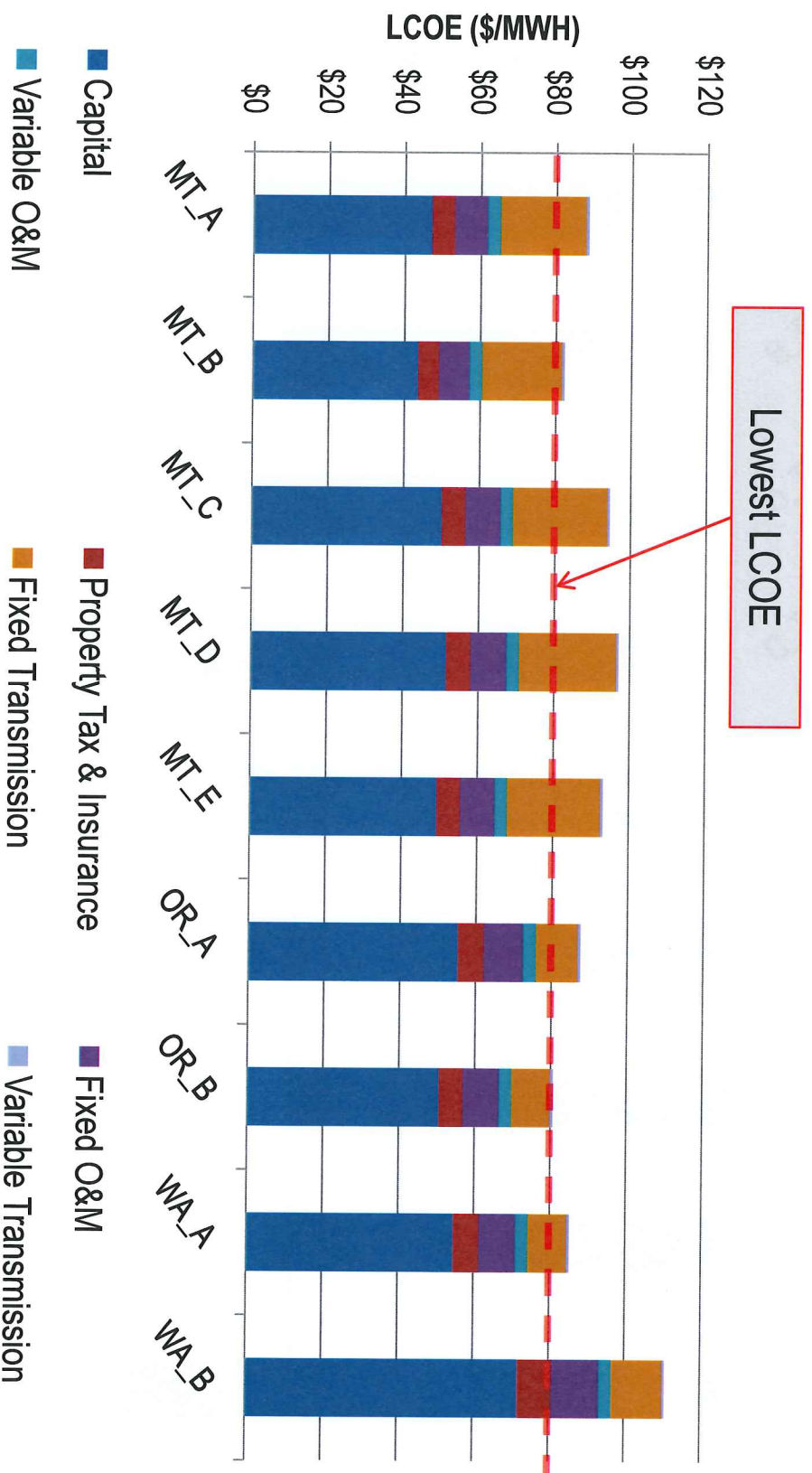
LCOE($/MWh) by Capacity Factor and Transmission Region

Values in red represent the approximate LCOE based on average capacity factor for that transmission region

IPP Financing

State	Region	Avg. Cap. Factor	25%	30%	35%	40%	45%	50%
MT	1	45.0%	$148	$124	$107	$94	$84	$76
MT	2	39.9%	$148	$124	$107	$94	$84	$76
MT	3	40.0%	$148	$124	$107	$94	$84	$76
OR	4	38.8%	$127	$106	$92	$81	$72	$66
WA	5	35.7%	$133	$112	$96	$85	$76	$69

Similar LCOE's across transmission regions result depending on higher or lower relative capacity factors

LCOE ($/MWh) After Removal of Montana Intertie Rate Component (MT Regions 2 and 3)

Values in red represent the approximate LCOE based on average capacity factor for that transmission region

State	Region		25%	30%	35%	40%	45%	50%
MT	1	2 – w/Intertie Cost	$148	$124	$107	$94	$84	$76
		2 - no Intertie Cost	$148	$124	$107	$94	$84	$76
		3 – w/Intertie Cost	$142	$119	$103	$90	$81	$73
		3 – w/Intertie Cost	$148	$124	$107	$94	$84	$76
		3 - no Intertie Cost	$142	$119	$103	$90	$81	$73
OR	OR Region 4		$127	$106	$92	$81	$72	$66
WA	WA Region 5		$133	$112	$96	$85	$76	$69

Removing BPA Intertie costs from those MT sites that would use the Intertie system (Colstrip to Garrison) decreases those projects' LCOE by ~4%

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MT Transmission Regions, with and w/out Montana Intertie costs

IPP LCOE, ES Assumptions

LCOE ($/MWH)

— MT Region - Intertie Cost   – – MT Region - No Intertie Cost

Graph represent LCOE for various capacity factors for MT Regions 2 and 3
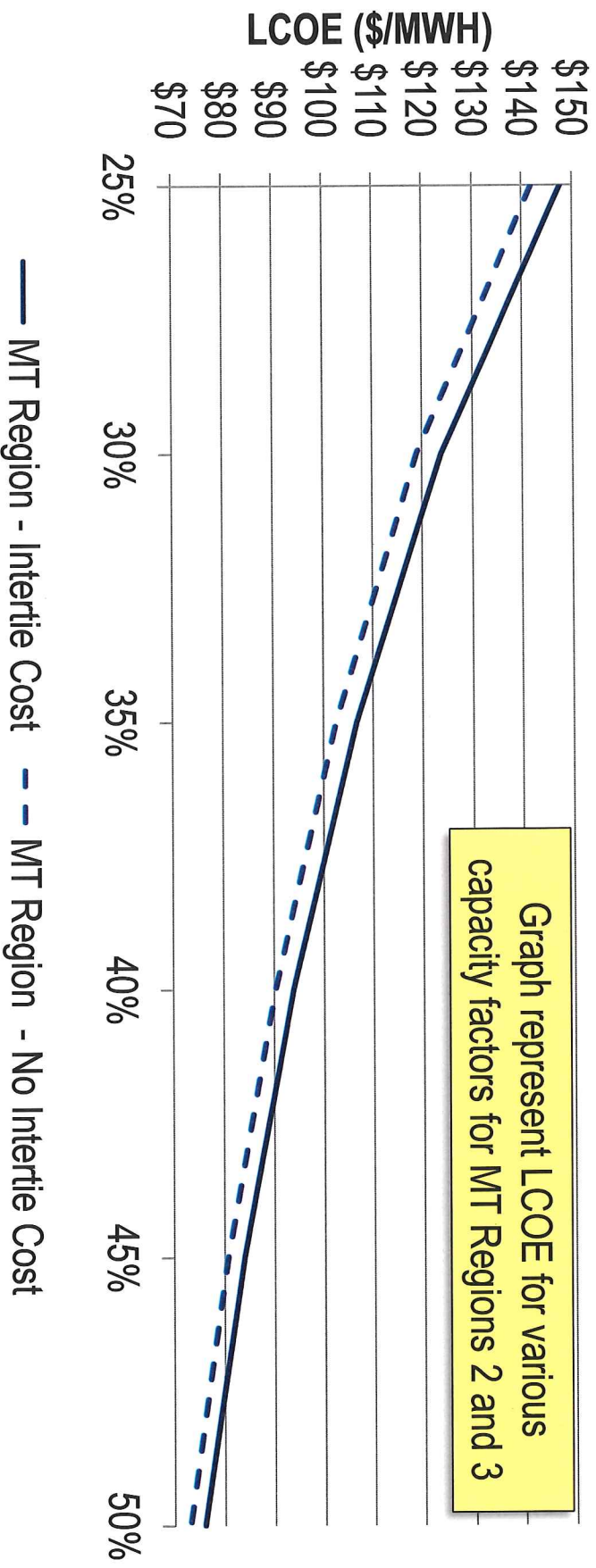
Removing the BPA intertie charge increases MT wind's competitiveness with OR and WA wind resources

Potential Transmission Constraints

Coal PPA Expirations & Coal Unit Retirements in Montana

Two events will impact transmission availability between Colstrip and PSE:

- Retirement or turndown of one or more coal units using the transmission contract paths from Montana to PSE
- Expansion of transmission facilities (none planned as of today)

These coal retirements or contract expirations may result in increased Available Transfer Capability (ATC) from Montana to PSE

Power Plant Name	Operating Capacity-MW	PPA Entity/Owner	End of PPA / Unit Shutdown
Colstrip Energy LP	40.5	NorthWestern	2024
Colstrip Unit 1	358	PSE/Talen	2022
Colstrip Unit 2	358	PSE/Talen	2022

Transmission Paths: MT to PSE

MONTANA

WECC Path 9 Cut Plane

No ATC identified

Available Transfer Capability; ATC (part of Colstrip Transmission)

Northwestern-BPA: 2016-2017

    POD BPAT - 158MW

    POD MLCK -176 MW

Broadview to Townsend

    PSE: 95-98 MW

    PGE: - 5 MW

    - 312 MW available in 2022

Currently, contract paths between Colstrip
& PSE's system are heavily subscribed.
Little to no available long-term firm ATC
west of the Garrison substation

Conclusions

Conclusions

1. Montana wind is more plentiful and generally of higher quality than Washington or Oregon wind

2. MT wind may be more valuable to PSE than LCOE alone suggests given that MT wind's profile aligns well with PSE's peak season (winter)

3. MT wind's summer peak capacity factor is comparable to that of OR and WA wind

4. The addition of MT wind to a portfolio of WA wind will provide resource diversity and security

5. MT wind is cost competitive with OR and WA wind even though the cost of transmitting MT wind to PSE's system erodes some of MT wind's LCOE advantage driven by higher capacity factor

6. Any reduction in MT wind transmission cost improves MT wind's cost competitiveness with WA and OR wind

7. With the planned closure of Colstrip 1 and 2, large quantities of ATC will become available from MT to PSE

Conclusions (p.2)

8. MT wind as a replacement for the Colstrip 1 and 2 will facilitate continued use of the "Colstrip line" which would benefit the transmission owners and their customers

9. Higher capacity factors in MT can overcome higher relative transmission costs.

10. High capacity factor sites, like MT's, will be less impacted on an LCOE basis by the costs of generator interconnection

11. Similarly, self-supplied losses from a higher capacity factor wind site would be less costly than from a lower capacity factor site

12. MT wind appears to be a viable and economic alternative to additional WA and/or OR wind in PSE's supply balance

13. When considering MT wind sites, PSE should seek locations that minimize transmission costs

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Introduction

Lazard's Levelized Cost of Energy ("LCOE") analysis addresses the following topics:

- Comparative "levelized cost of energy" analysis for various technologies on a $/MWh basis, including sensitivities, as relevant, for U.S. federal tax subsidies, fuel costs, geography and cost of capital, among other factors

- Comparison of the implied cost of carbon abatement for various generation technologies

- Illustration of how the cost of various generation technologies compares against illustrative generation rates in a subset of the largest metropolitan areas of the U.S.

- Illustration of utility-scale and rooftop solar versus peaking generation technologies globally

- Illustration of how the costs of utility-scale and rooftop solar and wind vary across the U.S., based on illustrative regional resources

- Illustration of the declines in the levelized cost of energy for various generation technologies over the past several years

- Comparison of assumed capital costs on a $/kW basis for various generation technologies

- Illustration of the impact of cost of capital on the levelized cost of energy for selected generation technologies

- Decomposition of the levelized cost of energy for various generation technologies by capital cost, fixed operations and maintenance expense, variable operations and maintenance expense, and fuel cost, as relevant

- Considerations regarding the usage characteristics and applicability of various generation technologies, taking into account factors such as location requirements/constraints, dispatch capability, land and water requirements and other contingencies

- Summary assumptions for the various generation technologies examined

- Summary of Lazard's approach to comparing the levelized cost of energy for various conventional and Alternative Energy generation technologies

Other factors would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this current analysis. These additional factors, among others, could include: capacity value vs. energy value; stranded costs related to distributed generation or otherwise; network upgrade, transmission or congestion costs or other integration-related costs; significant permitting or other development costs, unless otherwise noted; and costs of complying with various environmental regulations (e.g., carbon emissions offsets, emissions control systems). The analysis also does not address potential social and environmental externalities, including, for example, the social costs and rate consequences for those who cannot afford distribution generation solutions, as well as the long-term residual and societal consequences of various conventional generation technologies that are difficult to measure (e.g., nuclear waste disposal, environmental impacts, etc.). Lazard's LCOE aims to identify quantifiable, non-debatable costs. While prior versions of this study have presented the LCOE inclusive of the U.S. Federal Investment Tax Credit and Production Tax Credit, Versions 6.0 – 11.0 present the LCOE on an unsubsidized basis, except as noted on the page titled "Levelized Cost of Energy—Sensitivity to U.S. Federal Tax Subsidies"

Note: This study has been prepared by Lazard for general informational purposes only, and it is not intended to be, and should not be construed as, financial or other advice.

Unsubsidized Levelized Cost of Energy Comparison

Certain Alternative Energy generation technologies are cost-competitive with conventional generation technologies under some scenarios; such observation does not take into account potential social and environmental externalities (e.g., social costs of distributed generation, environmental consequences of certain conventional generation technologies, etc.), reliability or intermittency-related considerations (e.g., transmission and back-up generation costs associated with certain Alternative Energy technologies)

Chart: Levelized Cost ($/MWh)

Alternative Energy [1]

Technology	Range
Solar PV—Rooftop Residential ‡	$187 – $319
Solar PV—Rooftop C&I ‡	$85 – $194
Solar PV—Community ‡	$76 – $150
Solar PV—Crystalline Utility Scale [2]	$46 – $53
Solar PV—Thin Film Utility Scale [2]	$43 – $48
Solar Thermal Tower with Storage [3]	$98 – $181
Fuel Cell ‡	$106 – $167
Microturbine ‡	$59 – $89
Geothermal	$77 – $117
Biomass Direct	$55 – $114
Wind	$30 – $60

Diamond markers: $82 [4], $82 [4], $113 [6], $237 [5]

Conventional

Technology	Range
Natural Gas Reciprocating Engine [8] ‡	$68 – $106
Diesel Reciprocating Engine [7] ‡	$197 – $281
Gas Peaking	$156 – $210
IGCC [9]	$96 – $231
Nuclear [10]	$112 – $183
Coal [11]	$60 – $143
Gas Combined Cycle	$42 – $78

Levelized Cost ($/MWh)

Axis: $0, $50, $100, $150, $200, $250, $300, $350

Unsubsidized Levelized Cost of Energy Comparison (cont'd)

(1) Analysis excludes integration (e.g., grid and conventional generation investment to overcome system intermittency) costs for intermittent technologies.

(2) Low end represents single-axis tracking system. High end represents fixed-tilt design. Assumes 30 MW system in a high insolation jurisdiction (e.g., Southwest U.S.). Does not account for differences in heat coefficients within technologies, balance-of-system costs or other potential factors which may differ across select solar technologies or more specific geographies.

(3) Low and high end represent a concentrating solar tower with 10-hour storage capability. Low end represents an illustrative concentrating solar tower built in South Australia.

(4) Illustrative "PV Plus Storage" unit. PV and battery system (and related bi-directional inverter, power control electronics, etc.) sized to compare with solar thermal with 10-hour storage on capacity factor basis (52%). Assumes storage nameplate "usable energy" capacity of ~400 MWhdc, storage power rating of 110 MWac and ~200 MWac PV system. Implied output degradation of ~0.40%/year (assumes PV degradation of 0.5%/year and battery energy degradation of 1.5%/year, which includes calendar and cycling degradation). Battery round trip DC efficiency of 90% (including auxiliary losses). Storage opex of ~$8/kWh-year and PV O&M expense of ~$9.2/kW DC-year, with 20% discount applied to total opex as a result of synergies (e.g., fewer truck rolls, single team, etc.). Total capital costs of ~$3,456/kW include PV plus battery energy storage system and selected other development costs. Assumes 20-year useful life, although in practice the unit may perform longer. Illustrative system located in Southwest U.S.

(5) Diamond represents an illustrative solar thermal facility without storage capability.

(6) Represents estimated implied midpoint of levelized cost of energy for offshore wind, assuming a capital cost range of $2.36 – $4.50 per watt.

(7) Represents distributed diesel generator with reciprocating engine. Low end represents 95% capacity factor (i.e., baseload generation in poor grid quality geographies or remote locations). High end represents 10% capacity factor (i.e., to overcome periodic blackouts). Assumes replacement capital cost of 65% of initial total capital cost every 25,000 operating hours.

(8) Represents distributed natural gas generator with reciprocating engine. Low end represents 95% capacity factor (i.e., baseload generation in poor grid quality geographies or remote locations). High end represents 30% capacity factor (i.e., to overcome periodic blackouts). Assumes replacement capital cost of 65% of initial total capital cost every 60,000 operating hours.

(9) Does not include cost of transportation and storage. Low and high end depicts an illustrative recent IGCC facility located in the U.S.

(10) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies. Low and high end depicts an illustrative nuclear plant using the AP1000 design.

(11) Reflects average of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail coal. High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

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Levelized Cost of Energy—Sensitivity to U.S. Federal Tax Subsidies[1]

Given the extension of the Investment Tax Credit ("ITC") and Production Tax Credit ("PTC") in December 2015 and resulting subsidy visibility, U.S. federal tax subsidies remain an important component of the economics of Alternative Energy generation technologies (and government incentives are, generally, currently important in all regions)

Technology	Subsidized	Unsubsidized
Solar PV—Rooftop Residential	$145 – $240	$187 – $319
Solar PV—Rooftop C&I	$66 – $150	$85 – $194
Solar PV—Community	$60 – $119	$76 – $150
Solar PV—Crystalline Utility Scale[2]	$37 – $42	$46 – $53
Solar PV—Thin Film Utility Scale[2]	$35 – $38	$43 – $48
Solar Thermal Tower with Storage[3]		$98 – $181
Fuel Cell[4]	$79 – $140	$106 – $167
Geothermal[5]	$66 – $116	$77 – $117
Biomass Direct[6]		$55 – $114
Wind[6]	$14 – $52	$30 – $60

Levelized Cost ($/MWh)

Legend: ■ Subsidized   ■ Unsubsidized

Source: Lazard estimates.

(1) Unless otherwise noted, the subsidized analysis assumes projects placed into service in time to qualify for full PTC/ITC. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 10.0% cost and 20% common equity at 12.0% cost, unless otherwise noted.

(2) Low end represents a single-axis tracking system. High end represents a fixed-tilt design. Assumes 30 MW installation in high insolation jurisdiction (e.g., Southwest U.S.).

(3) Low and high end represent a concentrating solar tower with 10-hour storage capability. Low end represents an illustrative concentrating solar tower built in South Australia.

(4) The ITC for fuel cell technologies is capped at $1,500/0.5 kW of capacity.

(5) Reflects no ITC. Reflects 80% of $23/MWh PTC, escalated at ~1.5% annually for a term of 10 years.

(6) Reflects no ITC. Reflects 80% of $23/MWh PTC, escalated at ~1.5% annually for a term of 10 years. Due to high capacity factor and, relatedly, high PTC investor appetite, assumes 15% debt at 8.0% interest rate, 70% tax equity at 10.0% cost and 15% common equity at 12.0% cost.

Levelized Cost of Energy Comparison—Sensitivity to Fuel Prices

Variations in fuel prices can materially affect the levelized cost of energy for conventional generation technologies, but direct comparisons against "competing" Alternative Energy generation technologies must take into account issues such as dispatch characteristics (e.g., baseload and/or dispatchable intermediate load vs. peaking or intermittent technologies)

Alternative Energy

Technology	Range
Solar PV—Rooftop Residential	$187 – $319
Solar PV—Rooftop C&I	$85 – $194
Solar PV—Community	$76 – $150
Solar PV—Crystalline Utility Scale	$46 – $53
Solar PV—Thin Film Utility Scale	$43 – $48
Solar Thermal Tower with Storage	$98 – $181
Fuel Cell	$98 – $174
Geothermal	$77 – $117
Microturbine	$49 – $101
Biomass Direct	$51 – $122
Wind	$30 – $60

Conventional

Technology	Range
Diesel Reciprocating Engine	$154 – $327
Natural Gas Reciprocating Engine	$57 – $113
Gas Peaking	$147 – $218
IGCC	$94 – $233
Nuclear	$109 – $186
Coal	$57 – $148
Gas Combined Cycle	$35 – $85

Levelized Cost ($/MWh)

$0 $50 $100 $150 $200 $250 $300 $350
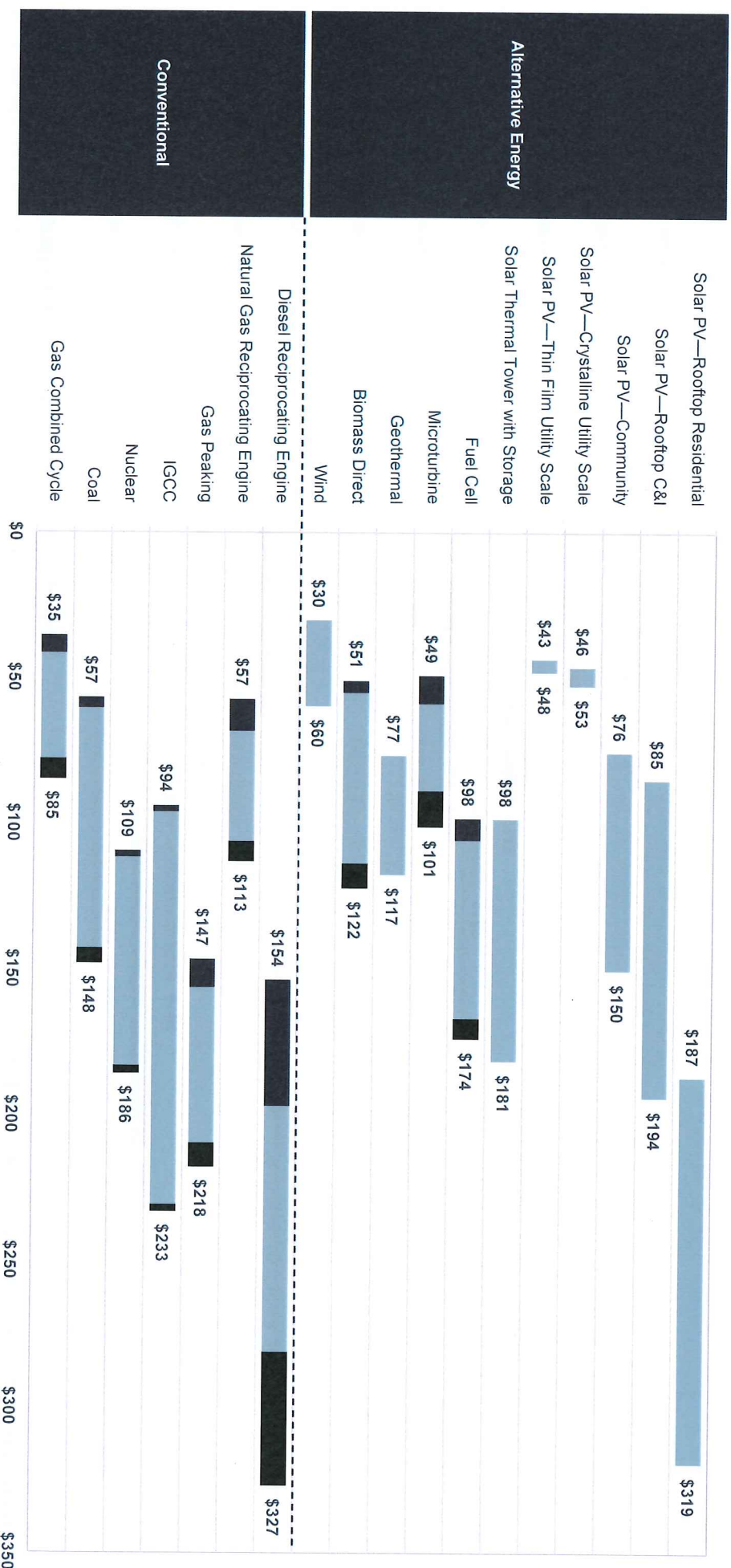
Source: Lazard estimates.
Note: Darkened areas in horizontal bars represent low end and high end levelized cost of energy corresponding with ±25% fuel price fluctuations.

Cost of Carbon Abatement Comparison

As policymakers consider the best and most cost-effective ways to limit carbon emissions, they should consider the implicit costs of carbon abatement of various Alternative Energy generation technologies; an analysis of such implicit costs suggests that policies designed to promote wind and utility-scale solar development could be a particularly cost-effective way of limiting carbon emissions; rooftop solar and solar thermal remain expensive, by comparison

- Such observation does not take into account potential social and environmental externalities or reliability or grid-related considerations

	Units	Conventional Generation			Alternative Energy Resources			
		Coal[2]	Gas Combined Cycle	Nuclear	Wind	Solar PV Rooftop	Solar PV Utility Scale[3]	Solar Thermal with Storage[4]
Capital Investment/KW of Capacity [1]	$/kW	$3,000	$686	$6,500	$1,200	$3,100	$1,375	$3,825
Total Capital Investment	$mm	$1,800	$480	$4,030	$1,212	$9,889	$2,558	$5,011
Facility Output	MW	600	700	620	1010	3190	1860	1310
Capacity Factor	%	93%	80%	90%	55%	18%	30%	43%
Effective Facility Output	MW	558	558	558	558	558	558	558
MWh/Year Produced [5]	GWh/yr	4,888	4,888	4,888	4,888	4,888	4,888	4,888
Levelized Cost of Energy	$/MWh	$60	$42	$112	$30	$187	$46	$98
Total Cost of Energy Produced	$mm/yr	$296 (2)	$203	$546	$147	$914	$226 (1)	$480
CO₂ Equivalent Emissions	Tons/MWh	0.92	0.51	—	—	—	—	—
Carbon Emitted	mm Tons/yr	4.51	2.50	—	—	—	—	—
Difference in Total Energy Cost	$mm/yr							
vs. Coal		—	($92)	$250	($148)	$619	($69) (4)	$185
vs. Gas		—	—	$342	($56)	$711	$23	$277
Difference in Carbon Emissions	mm Tons/yr							
vs. Coal		—	2.01	4.51	4.51	4.51	4.51	4.51
vs. Gas		—	—	2.50	2.50	2.50	2.50	2.50
Implied Abatement Cost/(Saving)	$/Ton							
vs. Coal		—	($46)	$55	($33)	$137	($15) (5)	$41
vs. Gas		—	—	$137	($22)	$284	$9	$111

Illustrative Implied Carbon Abatement Cost Calculation:

- (4) Difference in Total Energy Cost vs. Coal = (1) − (2)
  = $226 mm/yr (solar) − $296 mm/yr (coal) = ($69) mm/yr
- (5) Implied Abatement Cost vs. Coal = (4) ÷ (3)
  = ($69) mm/yr ÷ 4.51 mm Tons/yr = ($15)/Ton

Generation Rates for Selected Large U.S. Metropolitan Areas[1]

- Setting aside the legislatively mandated demand for solar and other Alternative Energy resources, utility-scale solar is becoming a more economically viable peaking energy product in many key, high population areas of the U.S. and, as pricing declines, could become economically competitive across a broader array of geographies

- Such observation does not take into account potential social and environmental externalities or reliability-related considerations

Price ($/MWh)

Metropolitan Statistical Area

Los Angeles $62
Chicago $59
Philadelphia $70
D.C. $75
Boston $94
Illustrative U.S. Generation-Only Charge $73

Rooftop Residential Solar $253
Gas Peaker $183
Community Solar $113
CCGT $60
Crystalline Utility-Scale Solar[2] $50
Thin Film Utility-Scale Solar[3] $46
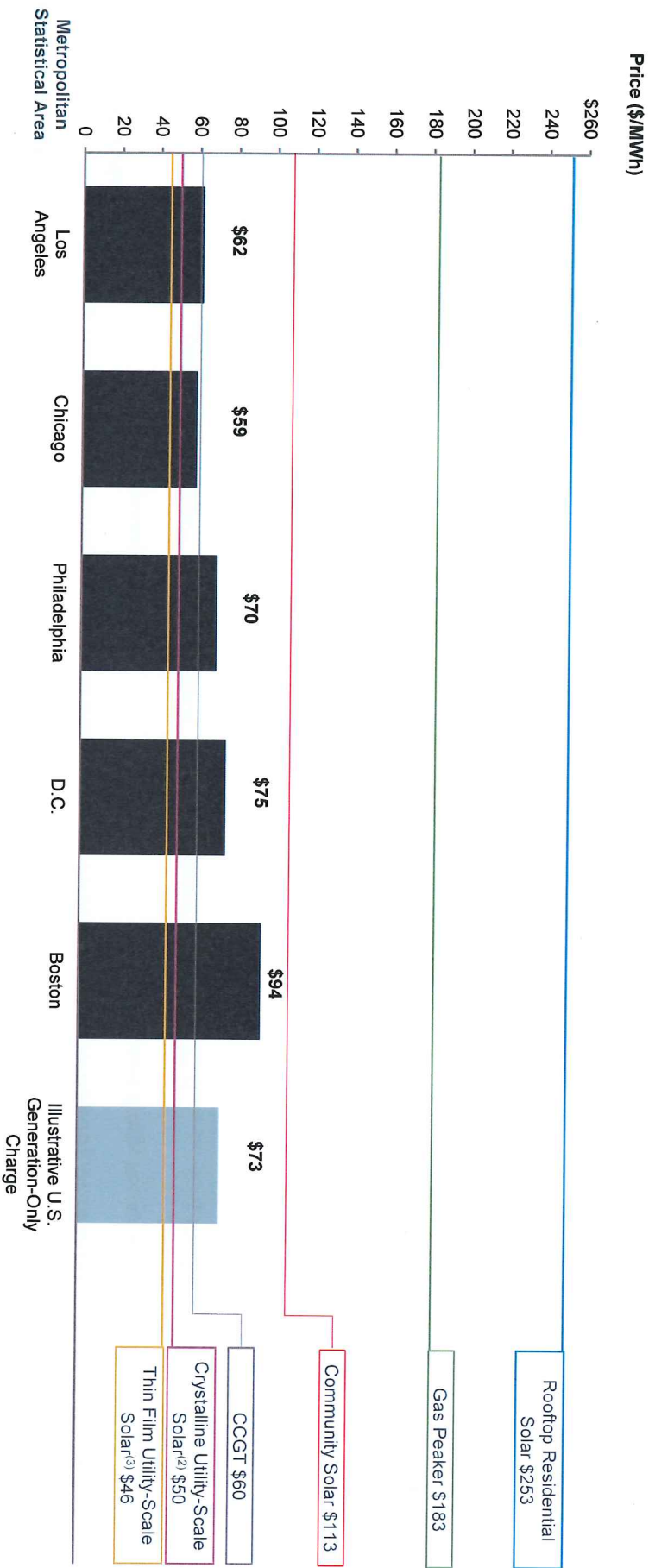
Source: EEI, Lazard estimates.

Note: Actual delivered generation prices may be higher, reflecting historical composition of resource portfolio. All technologies represent an average of the high and low levelized cost of energy values unless otherwise noted. Represents average retail rate for generation-only utility charges per EEI for 12 months ended December 31, 2016. Includes only those cities among top ten in population (per U.S. census) for which generation-only average $/kWh figures are available.

(1) Represents crystalline utility-scale solar with single-axis tracking design. Excludes Investment Tax Credit.
(2) Represents crystalline utility-scale solar with single-axis tracking design. Excludes Investment Tax Credit.
(3) Represents thin film utility-scale solar with single-axis tracking design. Excludes Investment Tax Credit.

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Solar versus Peaking Capacity—Global Markets

Solar PV can be an attractive resource relative to gas and diesel-fired peaking in many parts of the world due to high fuel costs; without storage, however, solar lacks the dispatch characteristics of conventional peaking technologies

Gas Peaker Versus Solar[1], [2]

Region	Solar	Gas Peaker/Diesel Generator
U.S.	$53 – $194	$156 – $210
Australia	$37 – $165	$149
Brazil	$57 – $223	$258
India	$52 – $191	$240 – $308
South Africa	$71 – $224	$252 – $326
Japan	$62 – $201	$234 – $300
Northern Europe	$70 – $189	$197 – $244 – $298

Diesel Reciprocating Engine Versus Solar[1], [3]

Region	Solar	Diesel Fuel Cost	Gas Peaker/Diesel Generator
U.S.	$53 – $197		$281
Australia	$37	$173	$246 – $270 – $358
Brazil	$57 – $225		$224 – $351
India	$71 – $205		$232 – $252 – $355
South Africa	$52 – $191	$219	$239 – $245 – $366
Japan	$62 – $263	$239	$298 – $351
Northern Europe	$70	$328 – $352	$444

Legend: ■ Solar | ┇ Diesel Fuel Cost | ▨ Gas Peaker/Diesel Generator

Levelized Cost ($/MWh): $0, $50, $100, $150, $200, $250, $300, $350, $400, $450

Source: World Bank, IHS Waterborne LNG and Lazard estimates.

(1) Low end assumes crystalline utility-scale solar with a fixed-tilt design. High end assumes rooftop C&I solar. Solar projects assume illustrative capacity factors of 26% – 30% for Australia, 26% – 28% for Brazil, 22% – 23% for India, 27% – 29% for South Africa, 16% – 18% for Japan and 13% – 16% for Northern Europe. Equity IRRs of 12% are assumed for Australia, Japan and Northern Europe and 18% for Brazil, India and South Africa; assumes cost of debt of 8% for Australia, Japan and Northern Europe, 14.5% for Brazil, 13% for India and 11.5% for South Africa.

(2) Assumes natural gas prices of $4.00 for Australia, $8.00 for Brazil, $7.00 for India, $7.00 for South Africa, $7.00 for Japan and $6.00 for Northern Europe (all in U.S. $ per MMBtu). Assumes a capacity factor of 10%.

(3) Diesel assumes high end capacity factor of 10% representing intermittent utilization and low end capacity factor of 95% representing baseload utilization. O&M cost of $30 per kW/year, heat rate of 9,500 – 10,000 Btu/kWh and total capital costs of $500 to $800 per kW of capacity. Assumes diesel prices of $3.60 for Australia, $2.90 for Brazil, $3.00 for India, $3.20 for South Africa, $3.50 for Japan and $4.80 for Northern Europe (all in U.S. $ per gallon).

Wind and Solar Resource—Regional Sensitivity (Unsubsidized)

The availability of wind and solar resources has a meaningful impact on the levelized cost of energy for various regions around the globe. This regional analysis varies capacity factors as a proxy for resource availability, while holding other variables constant. However, there are a variety of other factors (e.g., transmission, back-up generation/system reliability costs, labor rates, permitting and other costs, etc.) that would also impact regional costs

Solar[1]

Region	Value(s)
LCOE v11.0 Solar[2]	$46[3] $53 $194
Northeast U.S./Asia Pacific[4]	$62 $242
Southeast U.S./Italy[5]	$59 $228
Midwest U.S./Middle East[6]	$56 $215
Texas/Americas[7]	$43 $194
Southwest U.S./Americas[8]	$40 $176

Wind[9]

Region	Value(s)
LCOE v11.0 Wind	$30 $60
Northeast U.S./Northern Europe[10]	$41 $65
Southeast U.S./Europe[11]	$47 $75
Midwest U.S./Americas[12]	$30 $50
Texas/Americas[12]	$30 $50
Southwest U.S./Americas[13]	$33 $65

Levelized Cost ($/MWh): $0 $50 $100 $150 $200 $250

Source: Lazard estimates.

(1) Low end assumes a crystalline utility-scale solar fixed-tilt design, as tracking technologies may not be available in all geographies. High end assumes a rooftop C&I solar system.
(2) Low end assumes a crystalline utility-scale solar fixed-tilt design with a capacity factor of 21%.
(3) Diamond represents a crystalline utility-scale solar single-axis tracking system with a capacity factor of 30%.
(4) Assumes capacity factors of 16% – 18%. Asia Pacific includes Malaysia, the Philippines and Thailand.
(5) Assumes capacity factors of 17% – 19%.
(6) Assumes capacity factors of 18% – 20%. Middle East includes Israel, Turkey and the United Arab Emirates.
(7) Assumes capacity factors of 20% – 26%. Americas includes Guatemala, Honduras, Panama and Uruguay.
(8) Assumes capacity factors of 22% – 28%. Americas includes Brazil, Chile, Mexico and Peru.
(9) Assumes an onshore wind generation plant with capital costs of $1.20 – $1.65 per watt.
(10) Assumes capacity factors of 35% – 40%. Northern Europe includes Denmark and Sweden.
(11) Assumes capacity factors of 30% – 35%. Europe includes Germany, Italy, the Netherlands, Spain and the U.K.
(12) Assumes capacity factors of 45% – 55%. Americas includes Argentina and Brazil.
(13) Assumes capacity factors of 35% – 50%. Americas includes Chile, Mexico, Peru and Uruguay.

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Unsubsidized Levelized Cost of Energy—Wind & Solar PV (Historical)

Over the last eight years, wind and solar PV have become increasingly cost-competitive with conventional generation technologies, on an unsubsidized basis, in light of material declines in the pricing of system components (e.g., panels, inverters, racking, turbines, etc.), and dramatic improvements in efficiency, among other factors

Wind LCOE

Wind Eight-Year Percentage Decrease: 67%[1]

LCOE $/MWh		
— — Wind LCOE Mean	— Wind LCOE Range	

Solar PV LCOE

Utility-Scale Solar Eight-Year Percentage Decrease: 86%[1]

— — Crystalline Utility-Scale Solar LCOE Mean	— Crystalline Utility-Scale Solar LCOE Range[2]	— — Rooftop C&I Solar LCOE Mean	— Rooftop C&I Solar LCOE Range[3]

Source: Lazard estimates.
(1) Represents average percentage decrease of high end and low end of LCOE range.
(2) Low end represents crystalline utility-scale solar with single-axis tracking in high insolation jurisdictions (e.g., Southwest U.S.), while high end represents crystalline utility-scale solar with fixed-tilt design.
(3) Lazard's LCOE initiated reporting of rooftop C&I solar in 2010.

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Capital Cost Comparison

While capital costs for a number of Alternative Energy generation technologies (e.g., solar PV, solar thermal) are currently in excess of some conventional generation technologies (e.g., gas), declining costs for many Alternative Energy generation technologies, coupled with uncertain long-term fuel costs for conventional generation technologies, are working to close formerly wide gaps in electricity costs. This assessment, however, does not take into account issues such as dispatch characteristics, capacity factors, fuel and other costs needed to compare generation technologies

Alternative Energy

Technology	Capital Cost ($/kW)
Solar PV—Rooftop Residential	$3,100 – $3,600
Solar PV—Rooftop C&I	$2,000 – $3,750
Solar PV—Community	$1,900 – $3,100
Solar PV—Crystalline Utility Scale [1]	$1,100 – $1,400
Solar PV—Thin Film Utility Scale [1]	$1,100 – $1,400
Solar Thermal Tower with Storage [2]	$3,500 [3] – $3,500 [3]
Fuel Cell	$3,800 – $7,500
Geothermal	$4,000 – $6,400
Microturbine	$1,500 – $2,700
Biomass Direct	$1,700 – $4,000
Wind	$1,200 – $1,700

Conventional

Technology	Capital Cost ($/kW)
Diesel Reciprocating Engine	$500 – $800
Natural Gas Reciprocating Engine	$650 – $1,100
Gas Peaking	$800 – $1,000
IGCC [6]	$4,200 – $8,400
Nuclear [7]	$6,500 – $11,800
Coal [8]	$3,000 – $16,200
Gas Combined Cycle	$700 – $1,300

Solar Thermal Tower with Storage: $3,400 [5]

Capital Cost ($/kW) axis: $0, $1,500, $3,000, $4,500, $6,000, $7,500, $9,000, $10,500, $12,000, $13,500

Source:
Lazard estimates.
(1) High end capital cost represents the capital cost associated with the low end LCOE of utility-scale solar. Low end and capital cost represents the capital cost associated with the high end LCOE of utility-scale solar.
(2) Low and high end represent a concentrating solar tower with 10-hour storage capability. Low end represents an illustrative concentrating solar tower built in South Australia.
(3) Diamond represents PV plus storage.
(4) Diamond represents solar thermal tower capital costs without storage.
(5) Represents estimated midpoint of capital costs for offshore wind, assuming a capital cost range of $2.36 – $4.50 per watt.
(6) Low and high end represents Kemper and it incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.
(7) Low and high end depicts an illustrative nuclear plant using the AP1000 design.
(8) Reflects average of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail coal. Does not incorporate carbon capture and compression.

Levelized Cost of Energy Components—Low End

Certain Alternative Energy generation technologies are already cost-competitive with conventional generation technologies; a key factor regarding the long-term competitiveness of currently more expensive Alternative Energy technologies is the ability of technological development and increased production volumes to materially lower the capital costs of certain Alternative Energy technologies, and their levelized cost of energy, over time (e.g., as has been the case with solar PV and wind technologies)

Alternative Energy

Technology	Capital Cost	Fixed O&M	Variable O&M	Fuel Cost	Total
Solar PV—Rooftop Residential	$174	$13			$187
Solar PV—Rooftop C&I	$78	$7			$85
Solar PV—Community	$70	$5			$76
Solar PV—Crystalline Utility Scale (1)	$42	$5			$46
Solar PV—Thin Film Utility Scale (1)	$39	$4			$43
Solar Thermal Tower with Storage (2)	$78	$20			$98
Fuel Cell	$51	$30	$25		$106
Microturbine	$22	$1	$5 $31		$59
Geothermal	$47	$30			$77
Biomass Direct	$24	$7	$10	$15	$55
Wind	$24	$6			$30

Conventional

Technology	Capital Cost	Fixed O&M	Variable O&M	Fuel Cost	Total
Diesel Reciprocating Engine (3)	$13	$1	$10	$173	$197
Natural Gas Reciprocating Engine	$12	$2	$10	$44	$68
Gas Peaking	$112		$6 $5	$34	$156
Gas Combined Cycle	$16	$1	$4	$21	$42
IGCC (4)	$66	$11	$9 $8		$96
Nuclear (5)	$73	$15	$1	$9	$112
Coal (6)	$41	$5	$2	$13	$60

Levelized Cost ($/MWh): $0 $50 $100 $150 $200 $250

Legend: ■ Capital Cost ■ Fixed O&M ■ Variable O&M ■ Fuel Cost

Source: Lazard estimates.

(1) Represents the low end of a utility-scale solar single-axis tracking system.
(2) Represents concentrating solar tower with 10-hour storage capability.
(3) Represents continuous operation.
(4) Incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.
(5) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
(6) Reflects average of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail coal. Does not incorporate carbon capture and compression.

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Levelized Cost of Energy Components—High End

Certain Alternative Energy generation technologies are already cost-competitive with conventional generation technologies; a key factor regarding the long-term competitiveness of currently more expensive Alternative Energy technologies is the ability of technological development and increased production volumes to materially lower the capital costs of certain Alternative Energy technologies, and their levelized cost of energy, over time (e.g., as has been the case with solar PV and wind technologies)

Alternative Energy

Technology	
Solar PV—Rooftop Residential	$297 / $22 / $319
Solar PV—Rooftop C&I	$182 / $11 / $194
Solar PV—Community	$141 / $9 / $150
Solar PV—Crystalline Utility Scale [1]	$48 / $5 / $53
Solar PV—Thin Film Utility Scale [1]	$43 / $4 / $48
Solar Thermal Tower with Storage [2]	$164 / $18 / $181
Fuel Cell	$94 / $50 / $23 / $167
Geothermal	$77 / $40 / $117
Microturbine	$36 / $1 / $10 / $41 / $89
Biomass Direct	$53 / $14 / $15 / $29 / $114
Wind	$48 / $12 / $60

Conventional

Technology	
Diesel Reciprocating Engine [3]	$67 / $17 / $15 / $182 / $281
Natural Gas Reciprocating Engine	$28 / $8 / $15 / $55 / $106
Gas Peaking	$149 / $23 / $10 / $28 / $210
IGCC [4]	$203 / $11 / $9 / $8 / $231
Nuclear [5]	$110 / $17 / $1 / $9 / $183
Coal [6]	$50 / $2 / $2 / $24 / $78
Gas Combined Cycle	$50 / $10 / $5 / $18 / $143

Levelized Cost ($/MWh)

Legend: ■ Capital Cost ■ Fixed O&M ■ Variable O&M ■ Fuel Cost

Axis: $0 $50 $100 $150 $200 $250 $300 $350

Levelized Cost of Energy—Sensitivity to Cost of Capital

A key issue facing Alternative Energy generation technologies is the impact of the availability and cost of capital[1] on LCOEs (as a result of capital markets dislocation, technological maturity, etc.); availability and cost of capital have a particularly significant impact on Alternative Energy generation technologies, whose costs reflect essentially the return on, and of, the capital investment required to build them

LCOE[2] ($/MWh)

Axis: $0, 75, 150, 225, $300

Cost of capital sensitivity levels:

After-Tax IRR/WACC	5.4%	6.2%	6.9%	7.7%	8.4%	9.2%
Cost of Equity	9.0%	10.0%	11.0%	12.0%	13.0%	14.0%
Cost of Debt	5.0%	6.0%	7.0%	8.0%	9.0%	10.0%

Data series (by technology):

Technology							Δ
Solar PV—Rooftop Residential	$209	$224	$240	$253	$271	$286	+37%
Nuclear[3]	$114	$124	$137	$148	$163	$176	+59%
Solar PV—Rooftop C&I	$111	$123	$133	$140	$151	$161	+42%
Coal[4]	$83	$90	$96	$103	$109	$116	+39%
Solar PV—Crystalline Utility Scale	$53	$55	$57	$59	$62	$64	+21%
Onshore Wind	$39	$43	$46	$50	$54	$57	+46%
Gas—Combined Cycle	$39	$41	$43	$45	$47	$49	+28%

Legend

- Solar PV—Rooftop Residential
- Onshore Wind
- Gas—Combined Cycle
- Solar PV—Rooftop C&I
- Nuclear[3]
- Solar PV—Crystalline Utility Scale
- Coal[4]

☐ Reflects cost of capital assumption utilized in Lazard's Levelized Cost of Energy analysis

☐ Reflects potentially more prevalent North American cost of capital

Source: Lazard estimates.

(1) Cost of capital as used herein indicates the cost of capital for the asset/plant vs. the cost of capital of a particular investor/owner.
(2) Reflects average of high and low LCOE for given cost of capital assumption.
(3) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies. Does not incorporate carbon capture and compression.
(4) Based on average of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail coal. Does not incorporate carbon capture and compression.
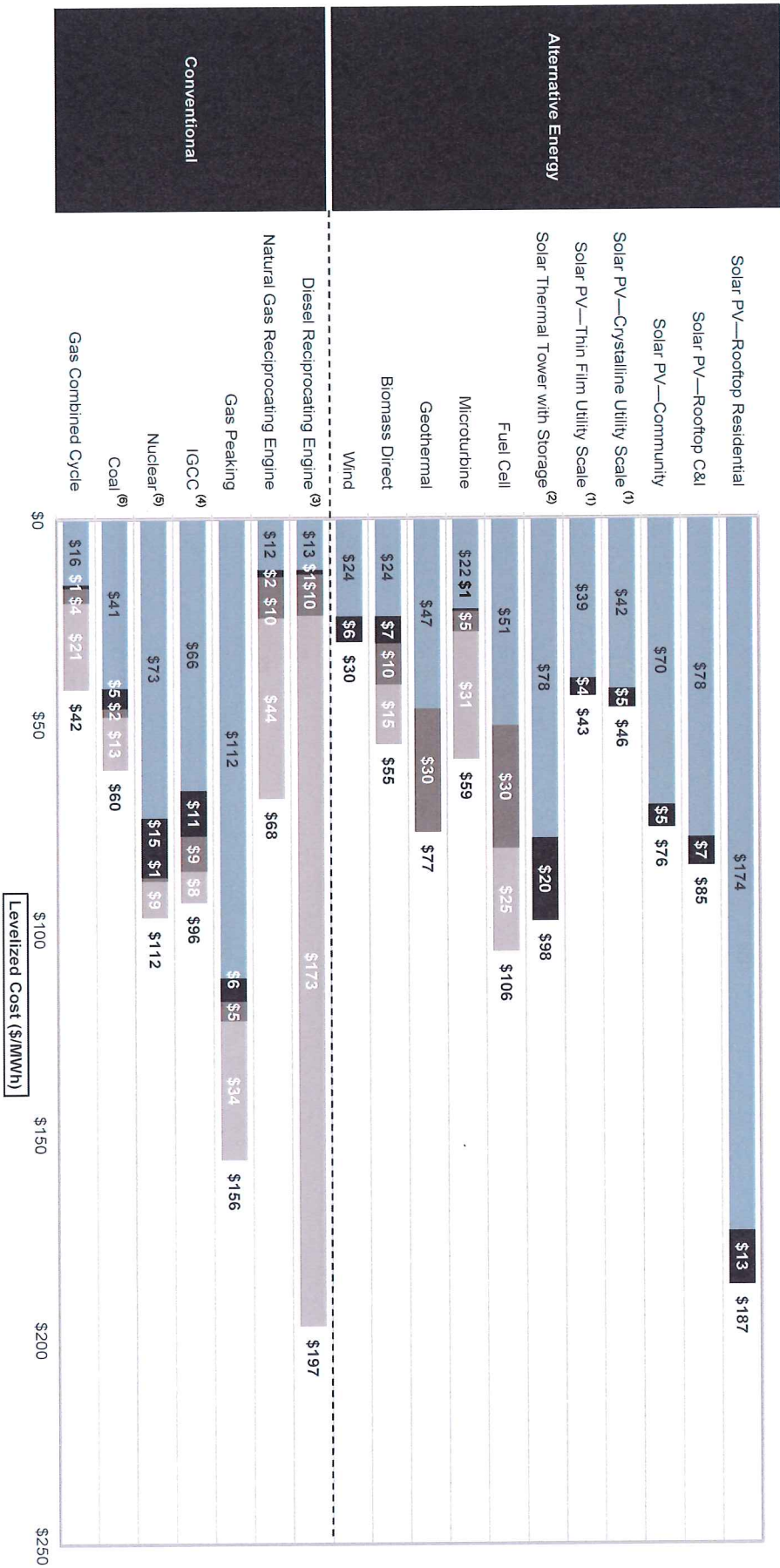
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Unsubsidized Levelized Cost of Energy—Cost of Capital Comparison

While Lazard's analysis primarily reflects an illustrative global cost of capital (i.e., 8% cost of debt and 12% cost of equity), such assumptions may be somewhat elevated vs. OECD/U.S. figures currently prevailing in the market for utility-scale renewables assets/investment—in general, Lazard aims to update its major levelized assumptions (e.g., cost of capital, capital structure, etc.) only in extraordinary circumstances, so that results track year-over-year cost declines and technological improvements vs. capital markets

Legend:
- ■ Cost of Capital: 6% CoD/10% CoE
- ■ Cost of Capital: 8% CoD/14% CoE

Alternative Energy[1]

Technology	Cost range ($/MWh)
Solar PV—Rooftop Residential ‡	$163 / $179 — $283 / $308
Solar PV—Rooftop C&I ‡	$74 / $81 — $168 / $179 / $186
Solar PV—Community	$65 / $72 — $128 / $143
Solar PV—Crystalline Utility Scale[2]	$40 / $44 — $45 / $50
Solar PV—Thin Film Utility Scale[2]	$37 / $41 — $41 / $46
Solar Thermal Tower with Storage[3]	$84 / $94 — $149 / $171
Fuel Cell ‡	$101 / $104 — $156 / $163
Microturbine ‡	$57 / $57 — $86 / $87
Geothermal	$70 / $74 — $106 / $113
Biomass Direct	$53 / $54 — $103 / $107
Wind	$27 / $29 — $54 / $58

Conventional

Technology	Cost range ($/MWh)
Diesel Reciprocating Engine[4]‡	$196 / $197 — $269 / $288
Natural Gas Reciprocating Engine[5]‡	$67 / $69 — $95 / $104
Gas Peaking	$143 / $157 — $192 / $211
IGCC[6]	$96 / $97 — $156
Nuclear[7]	$112 / $124 — $183 / $195 / $231
Coal[8]	$60 / $72 — $142
Gas Combined Cycle	$40 / $41 — $72 / $78

Levelized Cost ($/MWh): $0 $50 $100 $150 $200 $250 $300 $350

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Energy Resources: Matrix of Applications

While the LCOE for Alternative Energy generation technologies is, in some cases, competitive with conventional generation technologies, direct comparisons must take into account issues such as location (e.g., centralized vs. distributed) and dispatch characteristics (e.g., baseload and/or dispatchable intermediate load vs. peaking or intermittent technologies)

- **This analysis does not take into account potential social and environmental externalities or reliability-related considerations**

		Levelized Cost of Energy	Carbon Neutral/REC Potential	State of Technology	Location			Dispatch			
					Distributed	Centralized	Geography	Intermittent	Peaking	Load-Following	Base-Load
Alternative Energy	Solar PV[1]	$43 – $319	✓	Commercial	✓	✓	Universal[2]	✓	✓		
	Solar Thermal	$98 – $181	✓	Commercial		✓	Varies	✓	✓		
	Fuel Cell	$106 – $167	?	Emerging/Commercial	✓		Universal				✓
	Microturbine	$59 – $89	?	Commercial	✓		Universal				✓
	Geothermal	$77 – $117	✓	Commercial		✓	Varies				✓
	Biomass Direct	$55 – $114	✓	Commercial		✓	Universal			✓	✓
	Onshore Wind	$30 – $60	✓	Mature		✓	Varies	✓			
Conventional	Diesel Reciprocating Engine	$197 – $281	✗	Mature	✓		Universal	✓	✓		
	Natural Gas Reciprocating Engine	$68 – $106	✗	Mature	✓		Universal	✓	✓		
	Gas Peaking	$156 – $210	✗	Mature	✓	✓	Universal		✓	✓	✓
	IGCC	$96 – $231	✗[3]	Emerging[4]		✓	Co-located or rural		✓	✓	✓
	Nuclear	$112 – $183	✓	Mature/Emerging		✓	Co-located or rural				✓
	Coal	$60 – $143	✗[3]	Mature[4]		✓	Co-located or rural			✓	✓
	Gas Combined Cycle	$42 – $78	✗	Mature	✓	✓	Universal	✓	✓	✓	✓

Source: Lazard estimates.
(1) Represents the full range of solar PV technologies; low end represents thin film utility-scale solar single-axis tracking, high end represents the high end of rooftop residential solar.
(2) Qualification for RPS requirements varies by location.
(3) Could be considered carbon neutral technology, assuming carbon capture and compression.
(4) Carbon capture and compression technologies are in emerging stage.

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Levelized Cost of Energy—Methodology

Lazard's Levelized Cost of Energy analysis consists of creating a power plant model representing an illustrative project for each relevant technology and solving for the $/MWh figure that results in a levered IRR equal to the assumed cost of equity (see appendix for detailed assumptions by technology)

Wind — High Case Sample Calculations

Year[1]	0	1	2	3	4	5
Capacity (MW) – (A)		100	100	100	100	100
Capacity Factor (%) – (B)		38%	38%	38%	38%	38%
Total Generation ('000 MWh) – (A) x (B) = (C)*		333	333	333	333	333
Levelized Energy Cost ($/MWh) – (D)		$59.53	$59.53	$59.53	$59.53	$59.53
Total Revenues – (C) x (D) = (E)*		$19.8	$19.8	$19.8	$19.8	$19.8
Total Fuel Cost – (F)		$0.0	$0.0	$0.0	$0.0	$0.0
Total O&M – (G)*		4.0	4.1	4.2	4.3	4.4
Total Operating Costs – (F) + (G) = (H)		$4.0	$4.1	$4.2	$4.3	$4.4
EBITDA – (E) - (H) = (I)		$15.8	$15.7	$15.6	$15.5	$15.4
Debt Outstanding - Beginning of Period – (J)		$99.0	$97.0	$94.9	$92.6	$90.2
Debt - Interest Expense – (K)		(7.9)	(7.8)	(7.6)	(7.4)	(7.2)
Debt - Principal Payment – (L)		(2.0)	(2.1)	(2.3)	(2.5)	(2.7)
Levelized Debt Service – (K) + (L) = (M)		($9.9)	($9.9)	($9.9)	($9.9)	($9.9)
EBITDA – (I)		$15.8	$15.7	$15.6	$15.5	$15.4
Depreciation (MACRS) – (N)		(33.0)	(52.8)	(31.7)	(19.0)	(19.0)
Interest Expense – (K)		(7.9)	(7.8)	(7.6)	(7.4)	(7.2)
Taxable Income – (I) + (N) + (K) = (O)		($25.1)	($44.8)	($23.6)	($10.9)	($10.8)
Tax Benefit (Liability) – (O) x (tax rate) = (P)[2]		$10.0	$17.9	$9.5	$4.4	$4.3
After-Tax Net Equity Cash Flow – (I) + (M) + (P) = (Q)	($66.0)	$16.0	$23.8	$15.2	$10.0	$9.9

IRR For Equity Investors   **12.0%**

Key Assumptions[3]

Capacity (MW)		100
Capacity Factor		38%
Fuel Cost ($/MMBtu)[4]		$0.00
Heat Rate (Btu/kWh)		0
Fixed O&M ($/kW-year)		$40.0
Variable O&M ($/MWh)		$0.0
O&M Escalation Rate		2.25%
Capital Structure		
Debt		60.0%
Equity		40.0%
Cost of Debt		8.0%
Cost of Equity		12.0%
Taxes and Tax Incentives:		
Combined Tax Rate		40%
Economic Life (years)[5]		20
MACRS Depreciation (Year Schedule)		5
Capex		
EPC Costs ($/kW)		$1,050
Additional Owner's Costs ($/kW)		$600
Total Capital Costs ($/kW)		$1,650
Transmission Costs ($/kW)		$0
Total Capex ($mm)		$165

Legend:
- Technology-dependent
- Levelized

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Levelized Cost of Energy—Key Assumptions

		Solar PV					
	Units	Rooftop—Residential	Rooftop—C&I	Community	Utility Scale—Crystalline [3]	Utility Scale—Thin Film [3]	Solar Thermal Tower with Storage [4]
Net Facility Output	MW	0.005 – 0.002	1	1.5	30	30	110 – 135
EPC Cost	$/kW	$3,125 – $3,560	$2,000 – $3,750	$1,938 – $3,125	$1,375 – $1,100	$1,375 – $1,100	$3,344 – $8,750
Capital Cost During Construction	$/kW	—	—	—	—	—	$500 – $1,250
Other Owner's Costs	$/kW	included	included	included	included	included	included
Total Capital Cost [1]	$/kW	$3,125 – $3,560	$2,000 – $3,750	$1,938 – $3,125	$1,375 – $1,100	$1,375 – $1,100	$3,800 – $10,000
Fixed O&M	$/kW-yr	$20.00 – $25.00	$15.00 – $20.00	$12.00 – $16.00	$12.00 – $9.00	$12.00 – $9.00	$75.00 – $80.00
Variable O&M	$/MWh	—	—	—	—	—	—
Heat Rate	Btu/kWh	—	—	—	—	—	—
Capacity Factor	%	18% – 13%	25% – 20%	25% – 20%	30% – 21%	32% – 23%	43% – 52%
Fuel Price	$/MMBtu	0	0	0	0	0	0
Construction Time	Months	3	3	4 – 6	9	9	36
Facility Life	Years	20	25	30	30	30	35
CO_2 Emissions	lb/MMBtu	—	—	—	—	—	—
Levelized Cost of Energy [2]	$/MWh	$187 – $319	$85 – $194	$76 – $150	$46 – $53	$43 – $48	$98 – $181

Source: Lazard estimates.

(1) Includes capitalized financing costs during construction for generation types with over 24 months construction time.
(2) While prior versions of this study have presented LCOE inclusive of the U.S. Federal Investment Tax Credit and Production Tax Credit, Versions 6.0 – 11.0 present LCOE on an unsubsidized basis.
(3) Left column represents the assumptions used to calculate the low end LCOE for single-axis tracking. Right column represents the assumptions used to calculate the high end LCOE for fixed-tilt design. Assumes 30 MW system in high insolation jurisdiction (e.g., Southwest U.S.). Does not account for differences in heat coefficients, balance-of-system costs or other potential factors which may differ across solar technologies.
(4) Low and high end represent a concentrating solar tower with 10-hour storage capability. Low end represents an illustrative concentrating solar tower built in South Australia.

Levelized Cost of Energy—Key Assumptions (cont'd)

	Units	Fuel Cell	Microturbine	Geothermal	Biomass Direct	Wind—On Shore	Wind—Off Shore
Net Facility Output	MW	2.4	0.5 – 0.25	20 – 50	10	100.0	210 – 385
EPC Cost	$/kW	$3,000 – $7,500	$1,500 – $2,700	$3,500 – $5,600	$1,500 – $3,500	$900 – $1,050	$2,360 – $4,500
Capital Cost During Construction	$/kW	included	included	included	included	included	included
Other Owner's Costs	$/kW	$800 – $0		$500 – $800	$200 – $500	$300 – $600	
Total Capital Cost [1]	$/kW	$3,800 – $7,500	$1,500 – $2,700	$4,000 – $6,400	$1,700 – $4,000	$1,200 – $1,650	$2,360 – $4,500
Fixed O&M	$/kW-yr		$5.00 – $9.12		$50.00	$30.00 – $40.00	$80.00 – $110.00
Variable O&M	$/MWh	$30.00 – $50.00	$5.00 – $10.00	$30.00 – $40.00	$10.00	$0.00	$0.00
Heat Rate	Btu/kWh	7,260 – 6,600	9,000 – 12,000		14,500		
Capacity Factor	%	95%	95% – 85%	90% – 85%	85% – 80%	55% – 38%	50% – 40%
Fuel Price	$/MMBtu	3.45	$3.45		$1.00 – $2.00		
Construction Time	Months	3	3	36	36	12	12
Facility Life	Years	20	20	25	25	20	20
CO₂ Emissions	lb/MMBtu	0 – 117					
Levelized Cost of Energy [2]	$/MWh	$106 – $167	$59 – $89	$77 – $117	$55 – $114	$30 – $60	$71 – $155

Levelized Cost of Energy—Key Assumptions (cont'd)

	Units	Diesel Reciprocating Engine [3]	Natural Gas Reciprocating Engine	Gas Peaking	IGCC [4]	Nuclear [5]	Coal [6]	Gas Combined Cycle
Net Facility Output	MW	1 – 0.25	1 – 0.25	241 – 50	580	2,200	600	550
EPC Cost	$/kW	$500 – $800	$650 – $1,100	$530 – $700	$3,400 – $12,900	$4,900 – $8,900	$2,000 – $6,100	$400 – $1,000
Capital Cost During Construction	$/kW	—	—	—	$800 – $3,250	$1,300 – $2,400	$500 – $1,600	$0 – $100
Other Owner's Costs	$/kW	included	included	$220 – $300	$0 – $0	$292 – $501	$500 – $700	$200 – $200
Total Capital Cost [1]	$/kW	$500 – $800	$650 – $1,100	$750 – $1,000	$4,175 – $16,200	$6,500 – $11,800	$3,000 – $8,400	$700 – $1,300
Fixed O&M	$/kW-yr	$10.00	$15.00 – $20.00	$5.00 – $20.00	$73.00	$135.00	$40.00 – $80.00	$6.20 – $5.50
Variable O&M	$/MWh	$10.00	$10.00 – $15.00	$4.70 – $10.00	$8.50	$0.75	$2.00 – $5.00	$3.50 – $2.00
Heat Rate	Btu/kWh	9,500 – 10,000	8,000 – 10,000	9,804 – 8,000	11,708 – 11,700	10,450	8,750 – 12,000	6,133 – 6,900
Capacity Factor	%	95% – 10%	95% – 30%	10%	75%	90%	93%	80% – 40%
Fuel Price	$/MMBtu	$18.23	$5.50	$3.45	$0.65	$0.85	$1.47	$3.45
Construction Time	Months	3	3	12 – 18	57 – 63	69	60 – 66	24
Facility Life	Years	20	20	20	40	40	40	20
CO_2 Emissions	lb/MMBtu	0 – 117	0 – 117	117	169	—	211	117
Levelized Cost of Energy [2]	$/MWh	$197 – $281	$68 – $106	$156 – $210	$96 – $231	$112 – $183	$60 – $143	$42 – $78

Source: Lazard estimates.
(1) Includes capitalized financing costs during construction for generation types with over 24 months construction time.
(2) While prior versions of this study have presented LCOE inclusive of the U.S. Federal Investment Tax Credit and Production Tax Credit, Versions 6.0 – 11.0 present LCOE on an unsubsidized basis.
(3) Low end represents continuous operation. High end represents intermittent operation. Assumes diesel price of ~$2.50 per gallon.
(4) Incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.
(5) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
(6) Reflects average of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail coal. High end incorporates 90% carbon capture and compression. Does not include cost of storage and transportation.

Summary Considerations

Lazard has conducted this study comparing the levelized cost of energy for various conventional and Alternative Energy generation technologies in order to understand which Alternative Energy generation technologies may be cost-competitive with conventional generation technologies, either now or in the future, and under various operating assumptions, as well as to understand which technologies are best suited for various applications based on locational requirements, dispatch characteristics and other factors. We find that Alternative Energy technologies are complementary to conventional generation technologies, and believe that their use will be increasingly prevalent for a variety of reasons, including RPS requirements, carbon regulations, continually improving economics as underlying technologies improve and production volumes increase, and government subsidies in certain regions.

In this study, Lazard's approach was to determine the levelized cost of energy, on a $/MWh basis, that would provide an after-tax IRR to equity holders equal to an assumed cost of equity capital. Certain assumptions (e.g., required debt and equity returns, capital structure, etc.) were identical for all technologies in order to isolate the effects of key differentiated inputs such as investment costs, capacity factors, operating costs, fuel costs (where relevant) and other important metrics on the levelized cost of energy. These inputs were originally developed with a leading consulting and engineering firm to the Power & Energy Industry, augmented with Lazard's commercial knowledge where relevant. This study (as well as previous versions) has benefited from additional input from a wide variety of industry participants.

Lazard has not manipulated capital costs or capital structure for various technologies, as the goal of the study was to compare the current state of various generation technologies, rather than the benefits of financial engineering. The results contained in this study would be altered by different assumptions regarding capital structure (e.g., increased use of leverage) or capital costs (e.g., a willingness to accept lower returns than those assumed herein).

Key sensitivities examined included fuel costs and tax subsidies. Other factors would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this current analysis. These additional factors, among others, could include: capacity value vs. energy value; stranded costs related to distributed generation or otherwise; network upgrade, transmission or congestion costs; integration costs; and costs of complying with various environmental regulations (e.g., carbon emissions offsets, emissions control systems). The analysis also does not address potential social and environmental externalities, including, for example, the social costs and rate consequences for those who cannot afford distribution generation solutions, as well as the long-term residual and societal consequences of various conventional generation technologies that are difficult to measure (e.g., nuclear waste disposal, environmental impacts, etc.).

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Solar versus Peaking Capacity—Global Markets

Solar PV can be an attractive resource relative to gas and diesel-fired peaking in many parts of the world due to high fuel costs; without storage, however, solar lacks the dispatch characteristics of conventional peaking technologies

Gas Peaker Versus Solar[1], [2]

Country	Solar	Gas Peaker/Diesel Generator values
U.S.	$53	$156 $194
Australia	$37	$149 $210
Brazil	$57	$165 $223
India	$71	$224 $258 $326
South Africa	$52	$191 $240 $252 $308
Japan	$62	$234 $300
Northern Europe	$70	$189 $201 $254 $298

Diesel Reciprocating Engine Versus Solar[1], [3]

Country	Solar	Diesel Fuel Cost	Gas Peaker/Diesel Generator
U.S.	$53	$173	$197 $281
Australia	$37		$194 $244 $270
Brazil	$57	$198	$225 $224 $351
India	$71	$205	$232 $252 $351
South Africa	$52	$219	$191 $245 $355
Japan	$62	$239	$239 $263 $366
Northern Europe	$70	$328	$298 $352 $444

Legend: ■ Solar | Diesel Fuel Cost   ■ Gas Peaker/Diesel Generator

Levelized Cost ($/MWh) — axis: $0 $50 $100 $150 $200 $250 $300 $350 $400 $450

Source: *World Bank, IHS Waterborne LNG and Lazard estimates.*

(1) Low end assumes crystalline utility-scale solar with a fixed-tilt design. High end assumes rooftop C&I solar. Solar projects assume illustrative capacity factors of 26% – 30% for Australia, 26% – 28% for Brazil, 22% – 23% for India, 27% – 29% for South Africa, 16% – 18% for Japan and 13% – 16% for Northern Europe. Equity IRRs of 12% are assumed for Australia, Japan and Northern Europe and 18% for Brazil, India and South Africa; assumes cost of debt of 8% for Australia, Japan and Northern Europe, 14.5% for Brazil, 13% for India and 11.5% for South Africa.

(2) Assumes natural gas prices of $4.00 for Australia, $8.00 for Brazil, $7.00 for India, $7.00 for South Africa, $7.00 for Japan and $6.00 for Northern Europe (all in U.S. $ per MMBtu).
Assumes a capacity factor of 10%.

(3) Diesel assumes high end capacity factor of 10% representing intermittent utilization and low end capacity factor of 95% representing baseload utilization. O&M cost of $30 per kW/year, heat rate of 9,500 – 10,000 Btu/kWh and total capital costs of $500 to $800 per kW of capacity. Assumes diesel prices of $3.60 for Australia, $2.90 for Brazil, $3.00 for India, $3.20 for South Africa, $3.50 for Japan and $4.80 for Northern Europe (all in U.S. $ per gallon).

8

Wind and Solar Resource—Regional Sensitivity (Unsubsidized)

The availability of wind and solar resources has a meaningful impact on the levelized cost of energy for various regions around the globe. This regional analysis varies capacity factors as a proxy for resource availability, while holding other variables constant. However, there are a variety of other factors (e.g., transmission, back-up generation/system reliability costs, labor rates, permitting and other costs, etc.) that would also impact regional costs
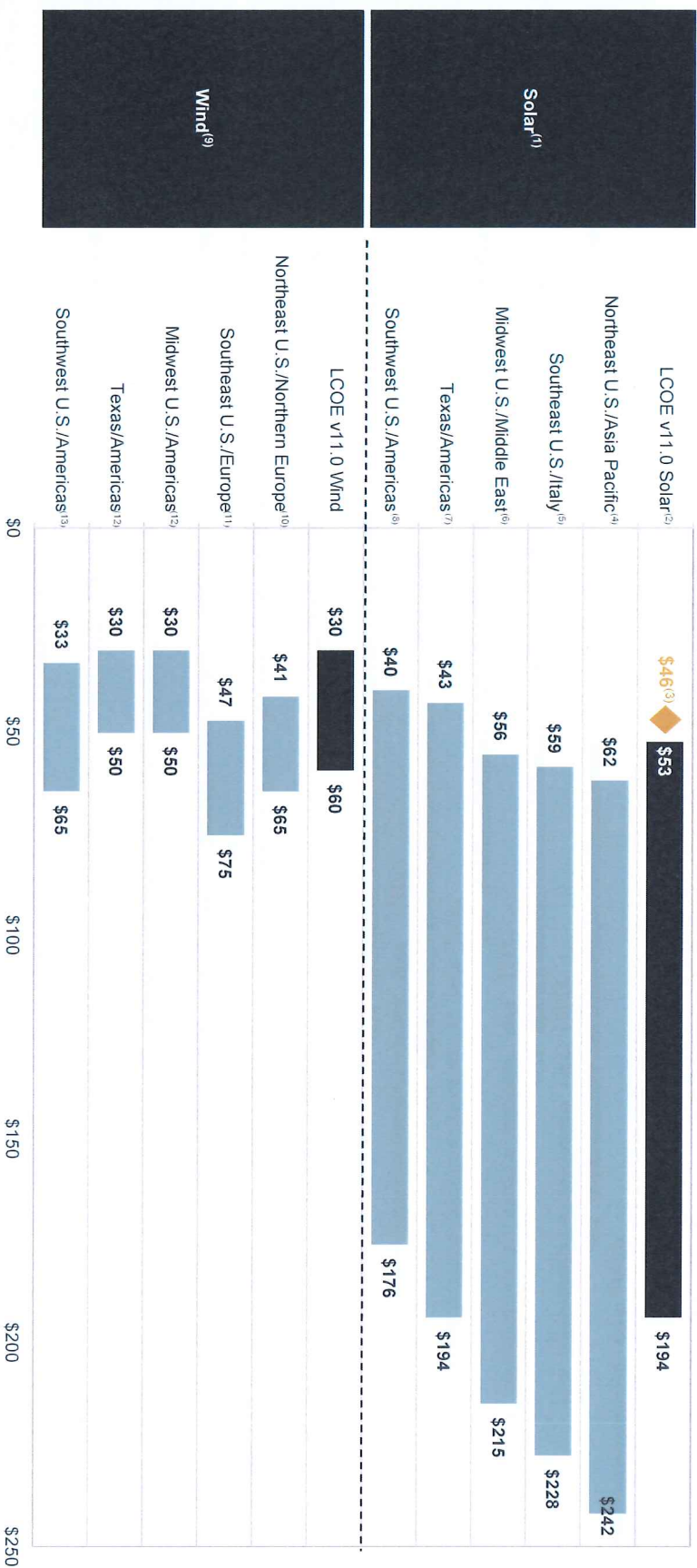

Chart: Levelized Cost ($/MWh)

Solar[1]

Region	Range
LCOE v11.0 Solar[2]	$46[3] (diamond) – $53 – $194
Northeast U.S./Asia Pacific[4]	$62 – $242
Southeast U.S./Italy[5]	$59 – $228
Midwest U.S./Middle East[6]	$56 – $215
Texas/Americas[7]	$43 – $194
Southwest U.S./Americas[8]	$40 – $176

Wind[9]

Region	Range
LCOE v11.0 Wind	$30 – $60
Northeast U.S./Northern Europe[10]	$41 – $65
Southeast U.S./Europe[11]	$47 – $75
Midwest U.S./Americas[12]	$30 – $50
Texas/Americas[12]	$30 – $50
Southwest U.S./Americas[13]	$33 – $65

Source: Lazard estimates.

(1) Low end assumes a crystalline utility-scale solar fixed-tilt design, as tracking technologies may not be available in all geographies. High end assumes a rooftop C&I solar system.
(2) Low end assumes a crystalline utility-scale solar fixed-tilt design with a capacity factor of 21%.
(3) Diamond represents a crystalline utility-scale solar single-axis tracking system with a capacity factor of 30%.
(4) Assumes capacity factors of 16% – 18%. Asia Pacific includes Malaysia, the Philippines and Thailand.
(5) Assumes capacity factors of 17% – 19%.
(6) Assumes capacity factors of 18% – 20%. Middle East includes Israel, Turkey and the United Arab Emirates.
(7) Assumes capacity factors of 20% – 26%. Americas includes Guatemala, Honduras, Panama and Uruguay.
(8) Assumes capacity factors of 22% – 28%. Americas includes Brazil, Chile, Mexico and Peru.
(9) Assumes an onshore wind generation plant with capital costs of $1.20 – $1.65 per watt.
(10) Assumes capacity factors of 35% – 40%. Northern Europe includes Denmark and Sweden.
(11) Assumes capacity factors of 30% – 35%. Europe includes Germany, Italy, the Netherlands, Spain and the U.K.
(12) Assumes capacity factors of 45% – 55%. Americas includes Argentina and Brazil.
(13) Assumes capacity factors of 35% – 50%. Americas includes Chile, Mexico, Peru and Uruguay.

Unsubsidized Levelized Cost of Energy—Wind & Solar PV (Historical)

Over the last eight years, wind and solar PV have become increasingly cost-competitive with conventional generation technologies, on an unsubsidized basis, in light of material declines in the pricing of system components (e.g., panels, inverters, racking, turbines, etc.), and dramatic improvements in efficiency, among other factors

Wind LCOE

LCOE $/MWh

Wind Eight-Year Percentage Decrease: 67%[1]

LCOE Version	3.0	4.0	5.0	6.0	7.0	8.0	9.0	10.0	11.0
	2009	2010	2011	2012	2013	2014	2015	2016	2017

Range values: $169/$101, $148/$99, $92/$50, $95/$48, $95/$45, $81/$37, $77/$32, $62/$32, $60/$30

Legend:
- – – Wind LCOE Mean
- —— Wind LCOE Range

Solar PV LCOE

LCOE $/MWh

Utility-Scale Solar Eight-Year Percentage Decrease: 86%[1]

LCOE Version	3.0	4.0	5.0	6.0	7.0	8.0	9.0	10.0	11.0
	2009	2010	2011	2012	2013	2014	2015	2016	2017

Crystalline Utility-Scale Solar LCOE ranges: $394/$323, $342/$270, $261/$166, $204/$149, $204/$149, $177/$126, $193/$109, $193/$88, $194/$85

Rooftop C&I Solar LCOE ranges: $226, $186/$148, $149/$101, $104/$91, $86/$72, $70/$58, $61/$53, $49/$46

Legend:
- – – Crystalline Utility-Scale Solar LCOE Mean
- —— Crystalline Utility-Scale Solar LCOE Range[2]
- – – Rooftop C&I Solar LCOE Mean
- —— Rooftop C&I Solar LCOE Range[3]

Source: Lazard estimates.
(1) Represents average percentage decrease of high end and low end of LCOE range.
(2) Low end represents crystalline utility-scale solar with single-axis tracking in high insolation jurisdictions (e.g., Southwest U.S.), while high end represents crystalline utility-scale solar with fixed-tilt design.
(3) Lazard's LCOE initiated reporting of rooftop C&I solar in 2010.

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Capital Cost Comparison

While capital costs for a number of Alternative Energy generation technologies (e.g., solar PV, solar thermal) are currently in excess of some conventional generation technologies (e.g., gas), declining costs for many Alternative Energy generation technologies, coupled with uncertain long-term fuel costs for conventional generation technologies, are working to close formerly wide gaps in electricity costs. This assessment, however, does not take into account issues such as dispatch characteristics, capacity factors, fuel and other costs needed to compare generation technologies
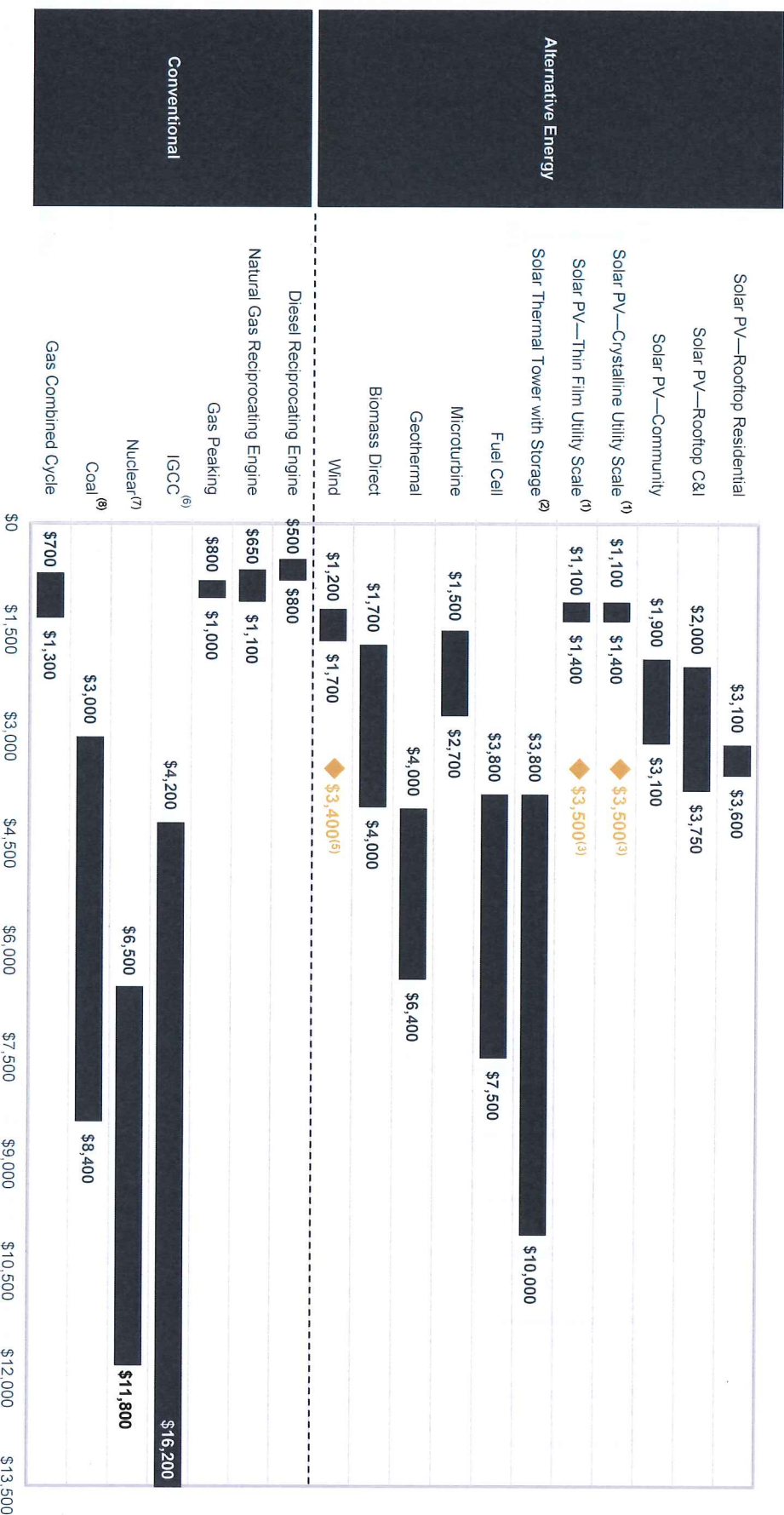
Alternative Energy

Technology	Capital Cost ($/kW)
Solar PV—Rooftop Residential	$3,100 – $3,600
Solar PV—Rooftop C&I	$2,000 – $3,750
Solar PV—Community	$1,900 – $3,100
Solar PV—Crystalline Utility Scale [1]	$1,100 – $1,400
Solar PV—Thin Film Utility Scale [1]	$1,100 – $1,400
Solar Thermal Tower with Storage [2]	$3,800 – $10,000
Fuel Cell	$3,800 – $3,500 [3]
Geothermal	$4,000 – $6,400
Microturbine	$1,500 – $2,700
Biomass Direct	$1,700 – $4,000
Wind	$1,200 – $1,700

Diamond markers: $3,500 [3], $3,500 [3], $3,400 [5]

Conventional

Technology	Capital Cost ($/kW)
Diesel Reciprocating Engine	$500 – $800
Natural Gas Reciprocating Engine	$650 – $1,100
Gas Peaking	$800 – $1,000
IGCC [6]	$4,200 – $8,400
Nuclear [7]	$6,500 – $11,800
Coal [8]	$3,000 – $8,400
Gas Combined Cycle	$700 – $1,300

IGCC [6] upper value: $16,200

Capital Cost ($/kW): $0, $1,500, $3,000, $4,500, $6,000, $7,500, $9,000, $10,500, $12,000, $13,500

Source:

Lazard estimates.

(1) High end capital cost represents the capital cost associated with the low end LCOE of utility-scale solar. Low end capital cost represents the capital cost associated with the high end LCOE of utility-scale solar.
(2) Low and high end represent a concentrating solar tower with 10-hour storage capability. Low end represents an illustrative concentrating solar tower built in South Australia.
(3) Diamond represents PV plus storage.
(4) Diamond represents solar thermal tower capital costs without storage.
(5) Represents estimated midpoint of capital costs for offshore wind, assuming a capital cost range of $2.36 – $4.50 per watt.
(6) Represents estimated Kemper and it incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.
(7) Low and high end depicts an illustrative nuclear plant using the AP1000 design.
(8) Reflects average of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail using the AP1000 design. Does not incorporate carbon capture and compression.

Levelized Cost of Energy Components—Low End

Certain Alternative Energy generation technologies are already cost-competitive with conventional generation technologies; a key factor regarding the long-term competitiveness of currently more expensive Alternative Energy technologies is the ability of technological development and increased production volumes to materially lower the capital costs of certain Alternative Energy technologies, and their levelized cost of energy, over time (e.g., as has been the case with solar PV and wind technologies)

Alternative Energy

Technology	Value
Solar PV—Rooftop Residential	$174 $13 = $187
Solar PV—Rooftop C&I	$78 $7 = $85
Solar PV—Community	$70 $5 = $76
Solar PV—Crystalline Utility Scale [1]	$42 $5 $46
Solar PV—Thin Film Utility Scale [1]	$39 $4 $43
Solar Thermal Tower with Storage [2]	$78 $20 $98
Fuel Cell	$51 $30 $25 = $106
Microturbine	$22 $1 $5 $31 $59
Geothermal	$47 $30 $77
Biomass Direct	$24 $7 $10 $15 $55
Wind	$6 $30

Conventional

Technology	Value
Natural Gas Reciprocating Engine	$12 $2 $10 $44 $68
Diesel Reciprocating Engine [3]	$13 $1 $10 $173 $197
Gas Peaking	$66 $112 $6 $5 $34 $156
IGCC [4]	$66 $11 $9 $8 $96
Nuclear [5]	$73 $15 $1 $9 $112
Coal [6]	$41 $5 $2 $13 $60
Gas Combined Cycle	$16 $1 $4 $21 $42

Legend: ■ Capital Cost ■ Fixed O&M ■ Variable O&M ■ Fuel Cost

Levelized Cost ($/MWh): $0 $50 $100 $150 $200 $250

Source: Lazard estimates.
(1) Represents the low end of a utility-scale solar single-axis tracking system.
(2) Represents concentrating solar tower with 10-hour storage capability.
(3) Represents continuous operation.
(4) Incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.
(5) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
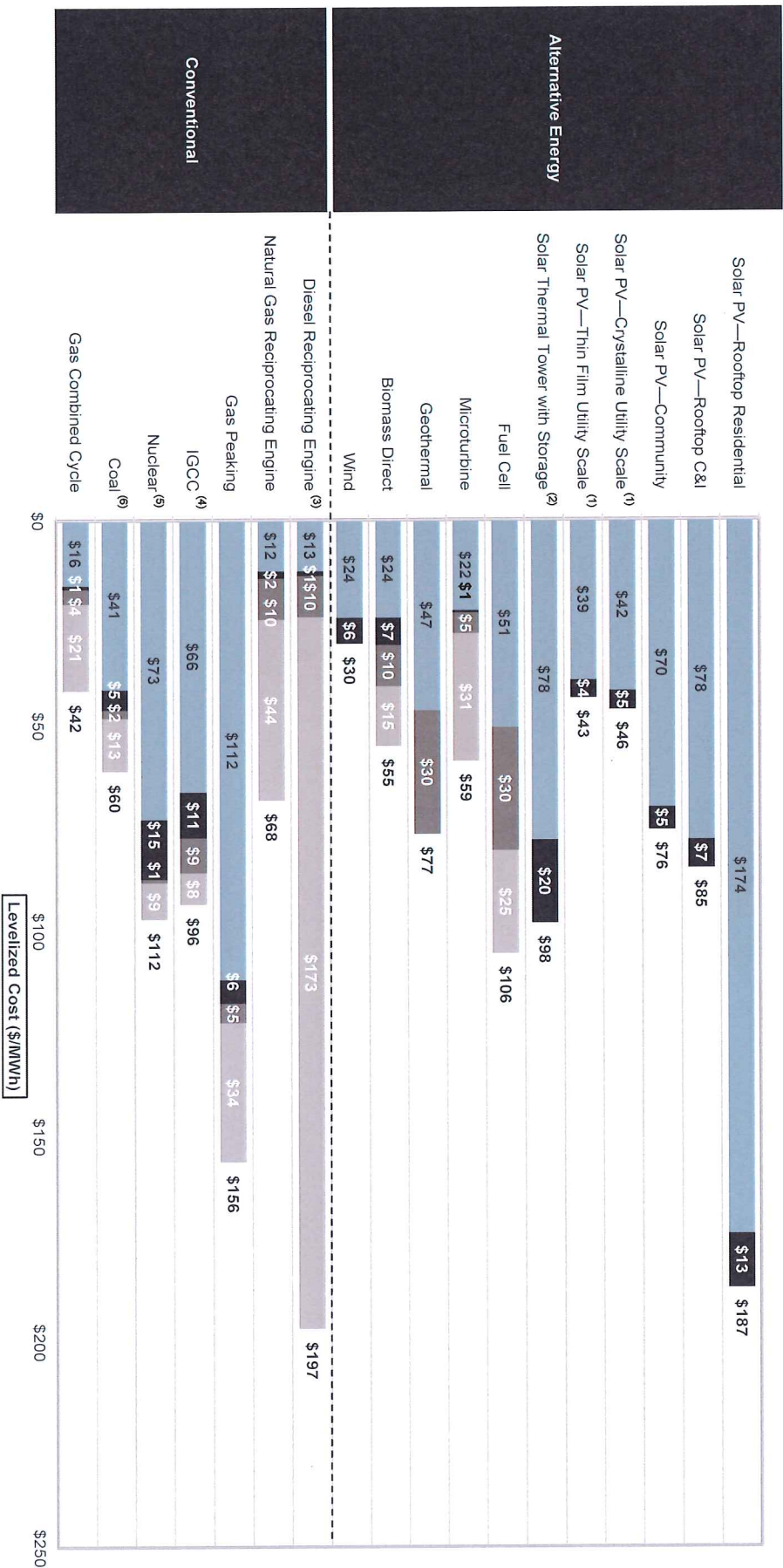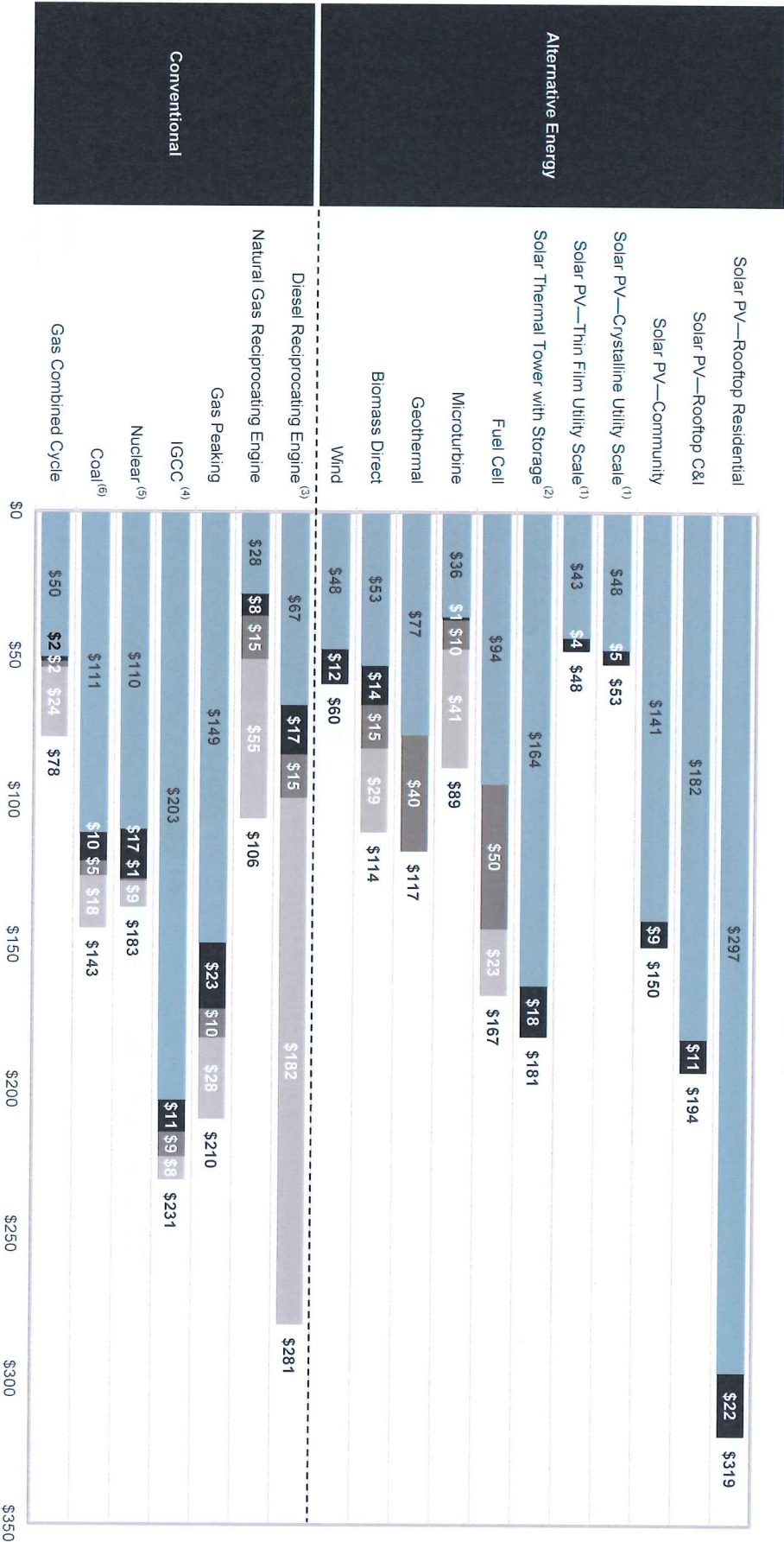(6) Reflects average of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail coal. Does not incorporate carbon capture and compression.

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Levelized Cost of Energy Components—High End

Certain Alternative Energy generation technologies are already cost-competitive with conventional generation technologies; a key factor regarding the long-term competitiveness of currently more expensive Alternative Energy technologies is the ability of technological development and increased production volumes to materially lower the capital costs of certain Alternative Energy technologies, and their levelized cost of energy, over time (e.g., as has been the case with solar PV and wind technologies)
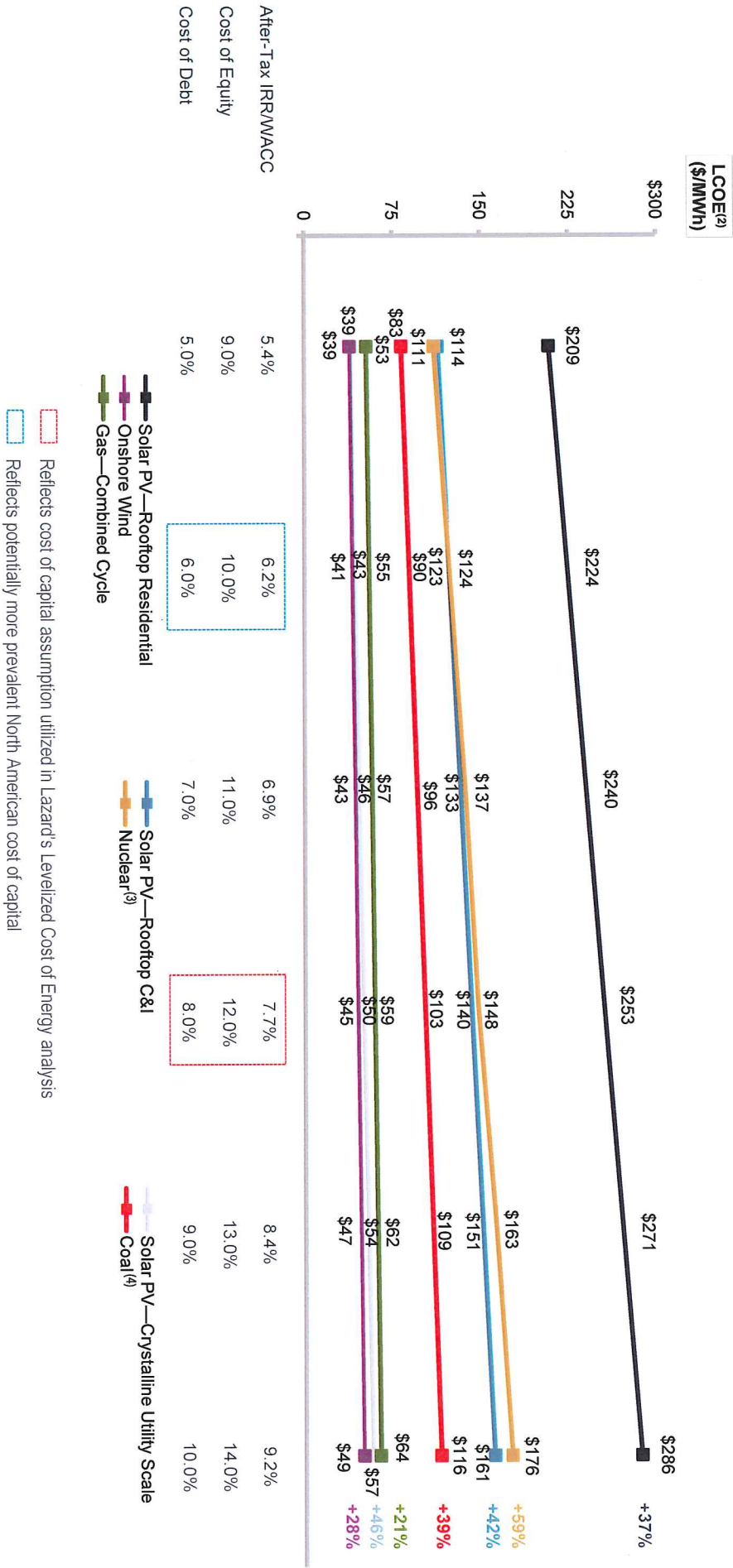
Alternative Energy

Technology		
Solar PV—Rooftop Residential	$297	$22 $319
Solar PV—Rooftop C&I	$182	$11 $194
Solar PV—Community	$141	$9 $150
Solar PV—Crystalline Utility Scale [1]	$48 $5 $53	
Solar PV—Thin Film Utility Scale [1]	$43 $4 $48	
Solar Thermal Tower with Storage [2]	$164 $18 $181	
Fuel Cell	$94 $50 $23 $167	
Geothermal	$77 $40 $117	
Microturbine	$36 $10 $41 $89	
Biomass Direct	$53 $14 $15 $29 $114	
Wind	$48 $12 $60	

Conventional

Technology		
Diesel Reciprocating Engine [3]	$67 $17 $15 $182 $281	
Natural Gas Reciprocating Engine	$28 $8 $15 $55 $106	
Gas Peaking	$149 $23 $10 $28 $210	
IGCC [4]	$203 $11 $9 $8 $231	
Nuclear [5]	$110 $17 $1 $9 $183	
Coal [6]	$111 $10 $5 $18 $143	
Gas Combined Cycle	$50 $2 $2 $24 $78	

Levelized Cost ($/MWh)

$0 $50 $100 $150 $200 $250 $300 $350

■ Capital Cost   ■ Fixed O&M   ■ Variable O&M   ■ Fuel Cost

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Levelized Cost of Energy—Sensitivity to Cost of Capital

A key issue facing Alternative Energy generation technologies is the impact of the availability and cost of capital[1] on LCOEs (as a result of capital markets dislocation, technological maturity, etc.); availability and cost of capital have a particularly significant impact on Alternative Energy generation technologies, whose costs reflect essentially the return on, and of, the capital investment required to build them
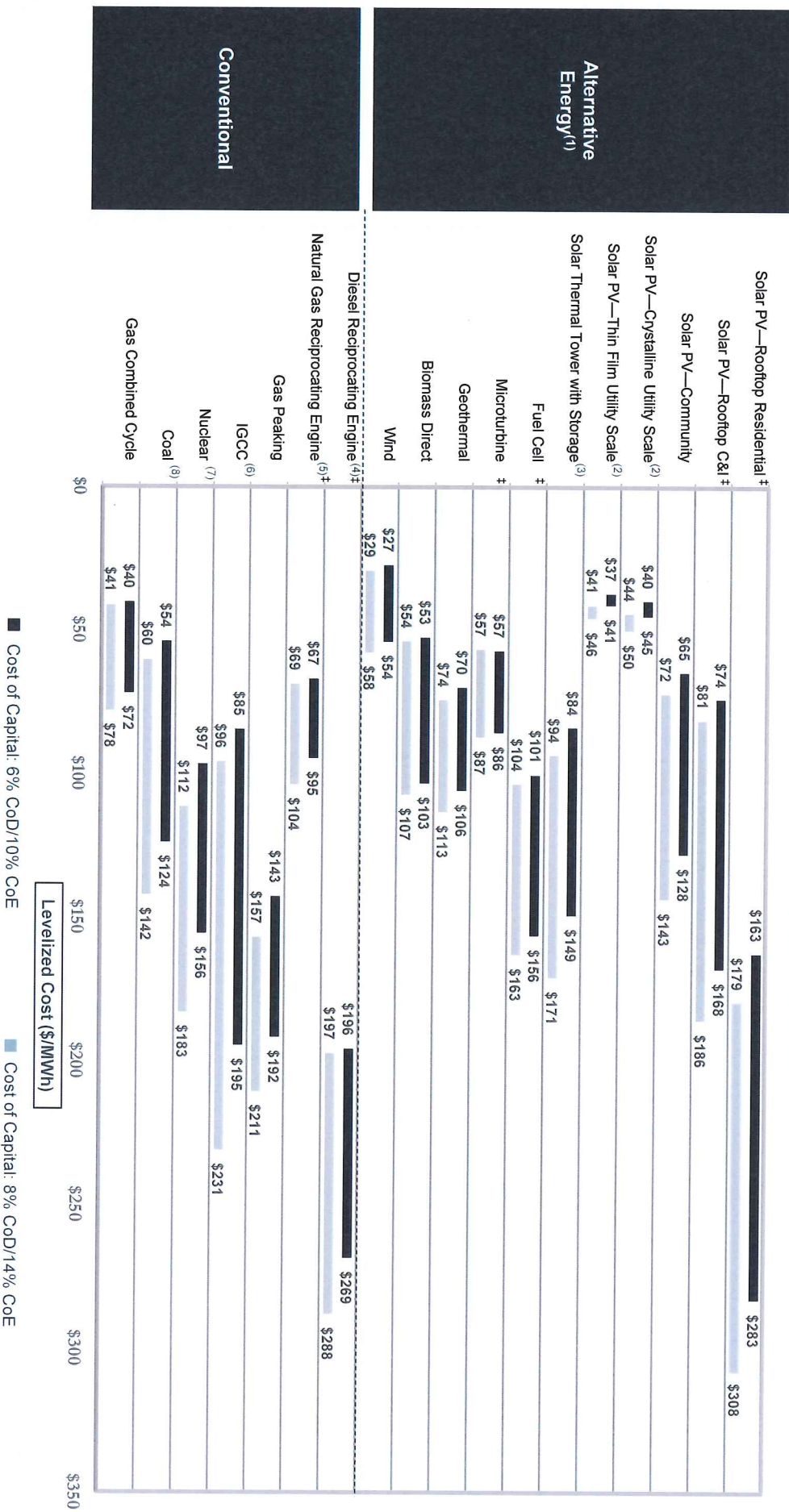
LCOE[2] ($/MWh)

	After-Tax IRR/WACC	Cost of Equity	Cost of Debt							
Solar PV—Rooftop Residential	5.4%	9.0%	5.0%	$209	$224	$240	$253	$271	$286	+37%
	6.2%	10.0%	6.0%							
	6.9%	11.0%	7.0%							
	7.7%	12.0%	8.0%							
	8.4%	13.0%	9.0%							
	9.2%	14.0%	10.0%							

Legend (left column):
- Solar PV—Rooftop Residential
- Onshore Wind
- Gas—Combined Cycle
- Reflects cost of capital assumption utilized in Lazard's Levelized Cost of Energy analysis
- Reflects potentially more prevalent North American cost of capital

Legend (middle column):
- Solar PV—Rooftop C&I
- Nuclear[3]

Legend (right column):
- Solar PV—Crystalline Utility Scale
- Coal[4]

Data values by technology (cost of capital increasing):

Technology							
Onshore Wind	$39	$41	$43	$45	$47	$49	+28%
Gas—Combined Cycle	$39	$43	$46	$50	$54	$57	+46%
Solar PV—Crystalline Utility Scale	$53	$55	$57	$59	$62	$64	+21%
Coal[4]	$83	$90	$96	$103	$109	$116	+39%
Nuclear[3]	$111	$123	$133	$140	$151	$161	+42%
Solar PV—Rooftop C&I	$114	$124	$137	$148	$163	$176	+59%
Solar PV—Rooftop Residential	$209	$224	$240	$253	$271	$286	+37%

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Unsubsidized Levelized Cost of Energy—Cost of Capital Comparison

While Lazard's analysis primarily reflects an illustrative global cost of capital (i.e., 8% cost of debt and 12% cost of equity), such assumptions may be somewhat elevated vs. OECD/U.S. figures currently prevailing in the market for utility-scale renewables assets/investment—in general, Lazard aims to update its major levelized assumptions (e.g., cost of capital, capital structure, etc.) only in extraordinary circumstances, so that results track year-over-year cost declines and technological improvements vs. capital markets

Alternative Energy[(1)]

Technology	Range
Solar PV—Rooftop Residential ‡	$163 – $283 ; $179 – $308 ; $168 – $186
Solar PV—Rooftop C&I ‡	$74 – $81 ; $72 – $128
Solar PV—Community	$65 – $143
Solar PV—Crystalline Utility Scale [(2)]	$40 – $45 ; $44 – $50
Solar PV—Thin Film Utility Scale [(2)]	$37 – $41 ; $41 – $46
Solar Thermal Tower with Storage [(3)]	$98 – $181
Fuel Cell ‡	$84 – $149 ; $94 – $171 ; $104 – $156 ; $101 – $163
Microturbine ‡	$57 – $86 ; $57 – $87
Geothermal	$70 – $106 ; $74 – $113
Biomass Direct	$53 – $103 ; $54 – $107
Wind	$27 – $54 ; $29 – $58

Conventional

Technology	Range
Solar Thermal Tower with Storage [(3)]	
Diesel Reciprocating Engine [(4)] ‡	$197 – $269 ; $196 – $288
Natural Gas Reciprocating Engine [(5)] ‡	$67 – $95 ; $69 – $104
Gas Peaking	$143 – $192 ; $157 – $211
IGCC [(6)]	$85 – $157 ; $96 – $195
Nuclear [(7)]	$97 – $112 ; $112 – $183 ; $124 – $156 ; $142 – $231
Coal [(8)]	$54 – $143 ; $60 ; $72
Gas Combined Cycle	$40 – $78 ; $41

■ Cost of Capital: 6% CoD/10% CoE
■ Cost of Capital: 8% CoD/14% CoE

Levelized Cost ($/MWh)

$0 $50 $100 $150 $200 $250 $300 $350

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Energy Resources: Matrix of Applications

While the LCOE for Alternative Energy generation technologies is, in some cases, competitive with conventional generation technologies, direct comparisons must take into account issues such as location (e.g., centralized vs. distributed) and dispatch characteristics (e.g., baseload and/or dispatchable intermediate load vs. peaking or intermittent technologies)

- **This analysis does not take into account potential social and environmental externalities or reliability-related considerations**

		Levelized Cost of Energy	Carbon Neutral/ REC Potential	State of Technology	Location			Dispatch			
					Distributed	Centralized	Geography	Intermittent	Peaking	Load-Following	Base-Load
Alternative Energy	Solar PV[1]	$43 – $319	✓	Commercial	✓	✓	Universal[2]	✓	✓		
	Solar Thermal	$98 – $181	✓	Commercial		✓	Varies	✓	✓	✓	✓
	Fuel Cell	$106 – $167	?	Emerging/ Commercial	✓		Universal				✓
	Microturbine	$59 – $89	?	Commercial	✓		Universal			✓	✓
	Geothermal	$77 – $117	✓	Mature		✓	Varies			✓	✓
	Biomass Direct	$55 – $114	✓	Mature		✓	Universal			✓	✓
	Onshore Wind	$30 – $60	✓	Mature		✓	Varies	✓			
Conventional	Diesel Reciprocating Engine	$197 – $281	✗	Mature	✓		Universal	✓	✓		✓
	Natural Gas Reciprocating Engine	$68 – $106	✗	Mature	✓		Universal	✓	✓	✓	✓
	Gas Peaking	$156 – $210	✗	Mature	✓	✓	Universal		✓	✓	✓
	IGCC	$96 – $231	✗[3]	Emerging[4]	✓	✓	Co-located or rural	✓	✓	✓	✓
	Nuclear	$112 – $183	✓	Mature/Emerging		✓	Co-located or rural		✓	✓	✓
	Coal	$60 – $143	✗[3]	Mature[4]		✓	Co-located or rural			✓	✓
	Gas Combined Cycle	$42 – $78	✗	Mature	✓	✓	Universal		✓	✓	✓

Source: Lazard estimates.

(1) Represents the full range of solar PV technologies; low end represents thin film utility-scale solar single-axis tracking, high end represents the high end of rooftop residential solar.
(2) Qualification for RPS requirements varies by location.
(3) Could be considered carbon neutral technology, assuming carbon capture and compression.
(4) Carbon capture and compression technologies are in emerging stage.

Levelized Cost of Energy—Methodology

Lazard's Levelized Cost of Energy analysis consists of creating a power plant model representing an illustrative project for each relevant technology and solving for the $/MWh figure that results in a levered IRR equal to the assumed cost of equity (see appendix for detailed assumptions by technology)

Wind — High Case Sample Calculations

Year[1]	0	1	2	3	4	5
Capacity (MW) – (A)		100	100	100	100	100
Capacity Factor (%) – (B)		38%	38%	38%	38%	38%
Total Generation ('000 MWh) – (A) x (B) = (C)*		333	333	333	333	333
Levelized Energy Cost ($/MWh) – (D)		$59.53	$59.53	$59.53	$59.53	$59.53
Total Revenues – (C) x (D) = (E)*		$19.8	$19.8	$19.8	$19.8	$19.8
Total Fuel Cost – (F)		$0.0	$0.0	$0.0	$0.0	$0.0
Total O&M – (G)*		4.0	4.1	4.2	4.3	4.4
Total Operating Costs – (F) + (G) = (H)		$4.0	$4.1	$4.2	$4.3	$4.4
EBITDA – (E) - (H) = (I)		$15.8	$15.7	$15.6	$15.5	$15.4
Debt Outstanding - Beginning of Period – (J)		$99.0	$97.0	$94.9	$92.6	$90.2
Debt - Interest Expense – (K)		(7.9)	(7.8)	(7.6)	(7.4)	(7.2)
Debt - Principal Payment – (L)		(2.0)	(2.1)	(2.3)	(2.5)	(2.7)
Levelized Debt Service – (K) + (L) = (M)		($9.9)	($9.9)	($9.9)	($9.9)	($9.9)
EBITDA – (I)		$15.8	$15.7	$15.6	$15.5	$15.4
Depreciation (MACRS) – (N)		(33.0)	(52.8)	(31.7)	(19.0)	(19.0)
Interest Expense – (K)		(7.9)	(7.8)	(7.6)	(7.4)	(7.2)
Taxable Income – (I) + (N) + (K) = (O)		($25.1)	($44.8)	($23.6)	($10.9)	($10.8)
Tax Benefit (Liability) – (O) x (tax rate) = (P)[2]		$10.0	$17.9	$9.5	$4.4	$4.3
After-Tax Net Equity Cash Flow – (I) + (M) + (P) = (Q)	($66.0)	$16.0	$23.8	$15.2	$10.0	$9.9

IRR For Equity Investors

12.0%

Key Assumptions[3]	
Capacity (MW)	100
Capacity Factor	38%
Fuel Cost ($/MMBtu)[4]	$0.00
Heat Rate (Btu/kWh)	0
Fixed O&M ($/kW-year)	$40.0
Variable O&M ($/MWh)	$0.0
O&M Escalation Rate	2.25%
Capital Structure	
Debt	60.0%
Cost of Debt	8.0%
Equity	40.0%
Cost of Equity	12.0%
Taxes and Tax Incentives:	
Combined Tax Rate	40%
Economic Life (years)[5]	20
MACRS Depreciation (Year Schedule)	5
Capex	
EPC Costs ($/kW)	$1,050
Additional Owner's Costs ($/kW)	$600
Transmission Costs ($/kW)	$0
Total Capital Costs ($/kW)	$1,650
Total Capex ($mm)	$165

Legend: ☐ Technology-dependent ☐ Levelized

Levelized Cost of Energy—Key Assumptions

		Solar PV			Utility Scale—Crystalline [3]	Utility Scale—Thin Film [3]	Solar Thermal Tower with Storage [4]
	Units	Rooftop—Residential	Rooftop—C&I	Community			
Net Facility Output	MW	0.005 – 0.002	1	1.5	30	30	110 – 135
EPC Cost	$/kW	$3,125 – $3,560	$2,000 – $3,750	$1,938 – $3,125	$1,375 – $1,100	$1,375 – $1,100	$3,344 – $8,750
Capital Cost During Construction	$/kW	—	—	—	—	—	$500 – $1,250
Other Owner's Costs	$/kW	included	included	included	included	included	included
Total Capital Cost [1]	$/kW	$3,125 – $3,560	$2,000 – $3,750	$1,938 – $3,125	$1,375 – $1,100	$1,375 – $1,100	$3,800 – $10,000
Fixed O&M	$/kW-yr	$20.00 – $25.00	$15.00 – $20.00	$12.00 – $16.00	$12.00 – $9.00	$12.00 – $9.00	$75.00 – $80.00
Variable O&M	$/MWh	—	—	—	—	—	—
Heat Rate	Btu/kWh	—	—	—	—	—	—
Capacity Factor	%	18% – 13%	25% – 20%	25% – 20%	30% – 21%	32% – 23%	43% – 52%
Fuel Price	$/MMBtu	0	0	0	0	0	0
Construction Time	Months	3	3	4 – 6	9	9	36
Facility Life	Years	20	25	30	30	30	35
CO_2 Emissions	lb/MMBtu	—	—	—	—	—	—
Levelized Cost of Energy [2]	$/MWh	$187 – $319	$85 – $194	$76 – $150	$46 – $53	$43 – $48	$98 – $181

Source: Lazard estimates.

(1) Includes capitalized financing costs during construction for generation types with over 24 months construction time.

(2) While prior versions of this study have presented LCOE inclusive of the U.S. Federal Investment Tax Credit and Production Tax Credit, Versions 6.0 – 11.0 present LCOE on an unsubsidized basis.

(3) Left column represents the assumptions used to calculate the low end LCOE for single-axis tracking. Right column represents the assumptions used to calculate the high end LCOE for fixed-tilt design. Assumes 30 MW system in high insolation jurisdiction (e.g., Southwest U.S.). Does not account for differences in heat coefficients, balance-of-system costs or other potential factors which may differ across solar technologies.

(4) Low and high end represent a concentrating solar tower with 10-hour storage capability. Low end represents an illustrative concentrating solar tower built in South Australia.

Levelized Cost of Energy—Key Assumptions (cont'd)

	Units	Fuel Cell	Microturbine	Geothermal	Biomass Direct	Wind—On Shore	Wind—Off Shore
Net Facility Output	MW	2.4	0.5 – 0.25	20 – 50	10	100.0	210 – 385
EPC Cost	$/kW	$3,000 – $7,500	$1,500 – $2,700	$3,500 – $5,600	$1,500 – $3,500	$900 – $1,050	$2,360 – $4,500
Capital Cost During Construction	$/kW	included	included	included	included	included	included
Other Owner's Costs	$/kW	$800 – $0	—	$500 – $800	$200 – $500	$300 – $600	—
Total Capital Cost [1]	$/kW	$3,800 – $7,500	$1,500 – $2,700	$4,000 – $6,400	$1,700 – $4,000	$1,200 – $1,650	$2,360 – $4,500
Fixed O&M	$/kW-yr	—	$5.00 – $9.12	—	$50.00	$30.00 – $40.00	$80.00 – $110.00
Variable O&M	$/MWh	$30.00 – $50.00	$5.00 – $10.00	$30.00 – $40.00	$10.00	$0.00	$0.00
Heat Rate	Btu/kWh	7,260 – 6,600	9,000 – 12,000	—	14,500	—	—
Capacity Factor	%	95%	95%	90% – 85%	85% – 80%	55% – 38%	50% – 40%
Fuel Price	$/MMBtu	3.45	$3.45	—	$1.00 – $2.00	—	—
Construction Time	Months	3	3	36	36	12	12
Facility Life	Years	20	20	25	25	20	20
CO_2 Emissions	lb/MMBtu	0 – 117	117	—	—	—	—
Levelized Cost of Energy [2]	$/MWh	$106 – $167	$59 – $89	$77 – $117	$55 – $114	$30 – $60	$71 – $155

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Levelized Cost of Energy—Key Assumptions (cont'd)

	Units	Diesel Reciprocating Engine [3]	Natural Gas Reciprocating Engine	Gas Peaking	IGCC [4]	Nuclear [5]	Coal [6]	Gas Combined Cycle
Net Facility Output	MW	1 – 0.25	1 – 0.25	241 – 50	580 – 2,200	2,200 – 600	600 – 550	550
EPC Cost	$/kW	$500 – $800	$650 – $1,100	$530 – $700	$3,400 – $12,900	$4,900 – $8,900	$2,000 – $6,100	$400 – $1,000
Capital Cost During Construction	$/kW	—	—	—	$800 – $3,250	$1,300 – $2,400	$500 – $1,600	$0 – $100
Other Owner's Costs	$/kW	included	included	$220 – $300	$0 – $0	$292 – $501	$500 – $700	$200 – $200
Total Capital Cost [1]	$/kW	$500 – $800	$650 – $1,100	$750 – $1,000	$4,175 – $16,200	$6,500 – $11,800	$3,000 – $8,400	$700 – $1,300
Fixed O&M	$/kW-yr	$10.00	$15.00 – $20.00	$5.00 – $20.00	$73.00	$135.00	$40.00 – $80.00	$6.20 – $5.50
Variable O&M	$/MWh	$10.00	$10.00 – $15.00	$4.70 – $10.00	$8.50	$0.75	$2.00 – $5.00	$3.50 – $2.00
Heat Rate	Btu/kWh	9,500 – 10,000	8,000 – 10,000	9,804 – 8,000	11,708 – 11,700	10,450	8,750 – 12,000	6,133 – 6,900
Capacity Factor	%	95% – 10%	95% – 30%	10%	75%	90%	93%	80% – 40%
Fuel Price	$/MMBtu	$18.23	$5.50	$3.45	$0.65	$0.85	$1.47	$3.45
Construction Time	Months	3	3	12 – 18	57 – 63	69	60 – 66	24
Facility Life	Years	20	20	20	40	40	40	20
CO₂ Emissions	lb/MMBtu	0 – 117	117	117	169	—	211	117
Levelized Cost of Energy [2]	$/MWh	$197 – $281	$68 – $106	$156 – $210	$96 – $231	$112 – $183	$60 – $143	$42 – $78

Source: Lazard estimates.
(1) Includes capitalized financing costs during construction for generation types with over 24 months construction time.
(2) While prior versions of this study have presented LCOE inclusive of the U.S. Federal Investment Tax Credit and Production Tax Credit, Versions 6.0 – 11.0 present LCOE on an unsubsidized basis.
(3) Low end represents continuous operation. High end represents intermittent operation. Assumes diesel price of ~$2.50 per gallon.
(4) Incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.
(5) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
(6) Reflects average of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail coal. High end incorporates 90% carbon capture and compression. Does not include cost of storage and transportation.

Summary Considerations

Lazard has conducted this study comparing the levelized cost of energy for various conventional and Alternative Energy generation technologies in order to understand which Alternative Energy generation technologies may be cost-competitive with conventional generation technologies, either now or in the future, and under various operating assumptions, as well as to understand which technologies are best suited for various applications based on locational requirements, dispatch characteristics and other factors. We find that Alternative Energy technologies are complementary to conventional generation technologies, and believe that their use will be increasingly prevalent for a variety of reasons, including RPS requirements, carbon regulations, continually improving economics as underlying technologies improve and production volumes increase, and government subsidies in certain regions.

In this study, Lazard's approach was to determine the levelized cost of energy, on a $/MWh basis, that would provide an after-tax IRR to equity holders equal to an assumed cost of equity capital. Certain assumptions (e.g., required debt and equity returns, capital structure, etc.) were identical for all technologies in order to isolate the effects of key differentiated inputs such as investment costs, capacity factors, operating costs, fuel costs (where relevant) and other important metrics on the levelized cost of energy. These inputs were originally developed with a leading consulting and engineering firm to the Power & Energy Industry, augmented with Lazard's commercial knowledge where relevant. This study (as well as previous versions) has benefited from additional input from a wide variety of industry participants.

Lazard has not manipulated capital costs or capital structure for various technologies, as the goal of the study was to compare the current state of various generation technologies, rather than the benefits of financial engineering. The results contained in this study would be altered by different assumptions regarding capital structure (e.g., increased use of leverage) or capital costs (e.g., a willingness to accept lower returns than those assumed herein).

Key sensitivities examined included fuel costs and tax subsidies. Other factors would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this current analysis. These additional factors, among others, could include: capacity value vs. energy value; stranded costs related to distributed generation or otherwise; network upgrade, transmission or congestion costs; integration costs; and costs of complying with various environmental regulations (e.g., carbon emissions offsets, emissions control systems). The analysis also does not address potential social and environmental externalities, including, for example, the social costs and rate consequences for those who cannot afford distribution generation solutions, as well as the long-term residual and societal consequences of various conventional generation technologies that are difficult to measure (e.g., nuclear waste disposal, environmental impacts, etc.).