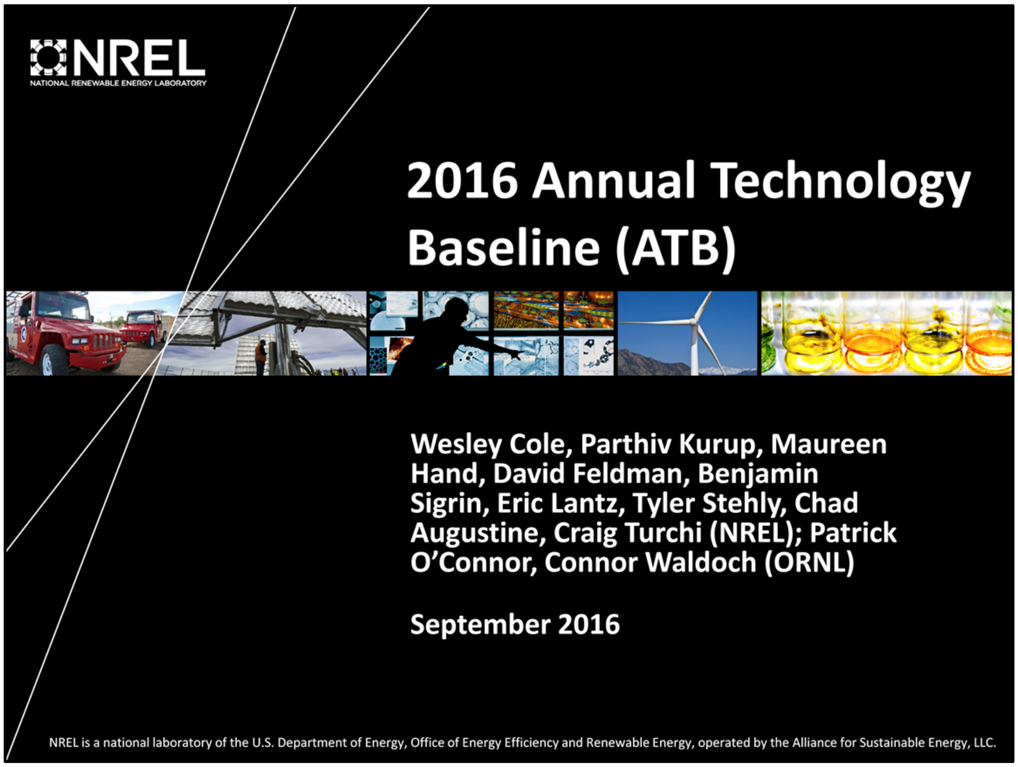

Notes pages provide additional detail and are essential for interpreting information on slides. Excel spreadsheet accompanies this documentation and contains all input data and calculations illustrated on subsequent pages.

All monetary values presented in 2014 U.S. dollars. Inflation rates for converting between dollar years were determined using the consumer price index as published by the U.S. Bureau of Labor and Statistics.

Recommended citation:
NREL (National Renewable Energy Laboratory). 2016. *2016 Annual Technology Baseline*. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/analysis/data_tech_baseline.html.

Disclaimer

DISCLAIMER AGREEMENT

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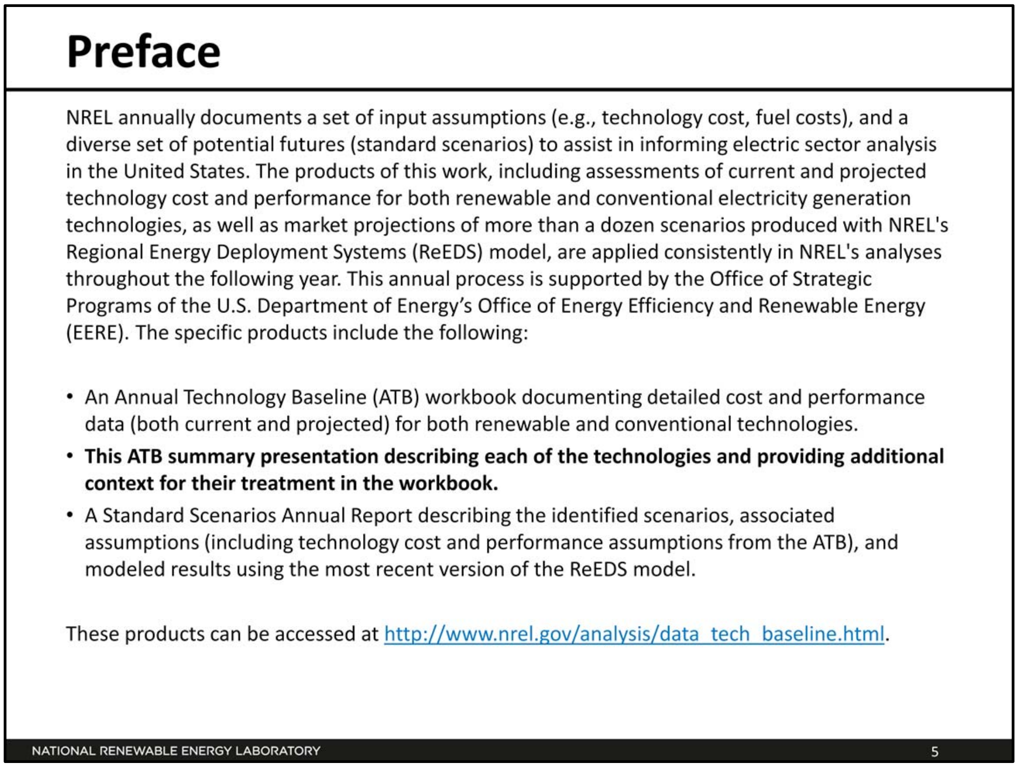
Table of Contents

1. 2016 ATB Overview



Preface
This presentation is one of several products resulting from an effort to provide a consistent set of technology cost and performance data and to define a conceptual and consistent scenario framework that can be used in NREL's future analyses. The long-term objective of this effort is to identify a range of possible futures of the U.S. electricity sector in which to consider specific energy system issues through (1) defining a set of prospective scenarios that bound ranges of key technology, market, and policy assumptions; and (2) assessing these scenarios in NREL's market models to understand the range of resulting outcomes, including energy technology deployment and production, energy prices, and CO_2 emissions.

The effort, supported by the U.S. Department of Energy's (DOE) Office of Energy Efficiency and Renewable Energy (EERE), has focused on the electric sector by creating a technology cost and performance database, defining scenarios, documenting associated assumptions, and generating modeled results using NREL's Regional Energy Deployment Systems Model (ReEDS). This work leverages and continues significant activity already being funded by EERE for individual technologies and market segments.
The specific products includes the following:

- An Annual Technology Baseline (ATB) workbook documenting detailed cost and performance data (both current and projected) for both renewable and conventional technologies.
- **This ATB summary presentation describing each of the technologies and providing additional context for their treatment in the workbook.**
- A 2016 Standard Scenarios Annual Report describing the identified scenarios, associated assumptions (including technology cost and performance assumptions from the ATB), modeled results, and the base structure of the specific version of the ReEDS model (v2016.1) (annual "release") used to generate the results.

These products can be accessed at http://www.nrel.gov/analysis/data_tech_baseline.html.

NREL intends to consistently apply these products in its ongoing electric sector scenarios analyses to ensure that the analyses incorporate a transparent, realistic, and timely set of input assumptions and consider a diverse set of potential futures. The application of standard scenarios, clear documentation of underlying assumptions, and model versioning is expected to result in

- improved transparency of critical input assumptions and modeling methodologies;
- improved comparability of results across studies;
- improved consideration of the potential economic and environmental impacts of generation technology improvement, changes in market conditions, and changes to policies and regulations; and
- an enhanced framework for formulating and addressing new analysis questions.

NREL plans to update the scenario framework and technology baseline annually and extend it to other technologies, models, and sectors, including transportation and the built environment.

Recent NREL Scenario Analyses

- 20% Wind Energy by 2030 (2008)
- Evaluating a Proposed 20% National Renewable Portfolio Standard (2009)
- SunShot Vision Study (2012)
- Renewable Electricity Futures Study – Exploration of High-Penetration Renewable Electricity Futures (2012)
- Beyond Renewable Portfolio Standards (2013)
- Integrated Canada-US Power Sector Modeling with ReEDS (2013)
- ReEDS Modeling of the President's 2020 U.S. Renewable Electricity Generation Goal (2014)
- Wind Vision Report (2015)
- Impacts of Renewable Energy Tax Credit Extensions (2016
- On the Path to SunShot (2016)
- Hydropower Vision (2016)
- Geothermal Vision (forthcoming)

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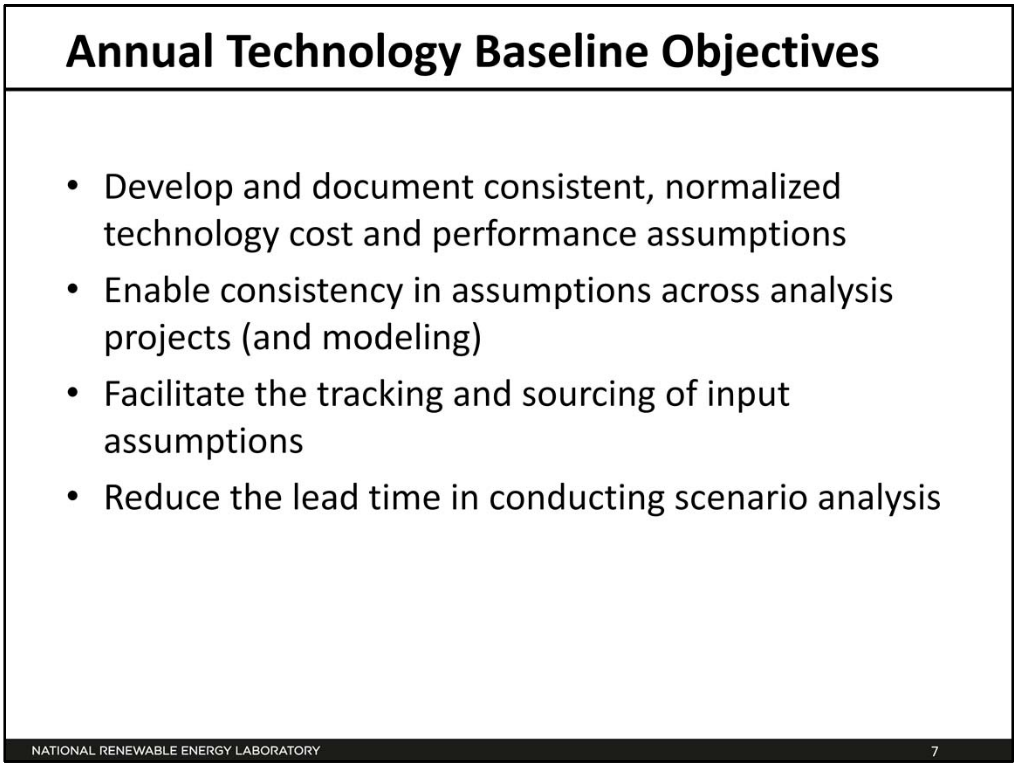
These examples of recent NREL scenario analyses all required technology cost and performance assumptions, and motivated the creation of the ATB in order to improve the consistency across the analyses.

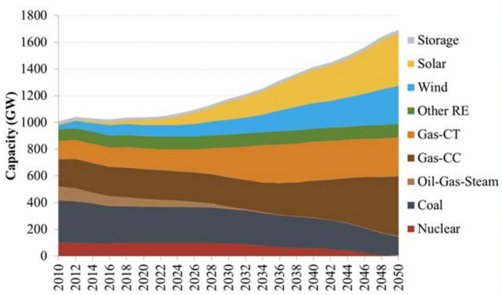


With the increased reliance on NREL's data and modeling tools for studies for EERE and other stakeholders, we collectively recognized the need and opportunity to establish a process to develop and communicate the underlying data and assumptions on which they are based.

Scenario analyses have become an integral component of the technology analysis portfolio conducted at the DOE and NREL, and are used to inform long-term R&D strategies. The cost and performance of technologies today and into the future are critical drivers of the evolution of the power system. Transparent, harmonized assumptions are crucial for conducting robust scenario analysis to inform R&D strategies.

Standard Scenarios and Relationship to ATB

- The Standard Scenarios create an ensemble of standard scenarios for the future – initially presented through NREL's ReEDS modeling results
  - Illustrate the model's solution space
  - Provide a jump-start for analysis projects using ReEDS
  - Varying over anticipated drivers and specific storylines
- Publish an annual report of standard scenario results and modeling assumptions
- 2016 Standard Scenarios report to be published in late summer 2016
- **The ATB provides the technology cost and performance assumptions for renewable and conventional technologies**



Group	Scenario	Notes
Fossil Fuel Costs	AEO 2014 Reference Fuel Cost Low NG and Coal Costs High NG and Coal Costs	Fossil Fuel Cost Cases (AEO 2014): *Reference*: AEO 2014 NG and Coal Reference *Low*: High Oil & Gas Resource + Low Coal Price *High*: Low Oil & Gas Resource + High Coal Price
Demand Growth	AEO 2014 Reference Demand Growth AEO Low EE adoption AEO High EE adoption	Demand Growth Rate Cases: *Reference*: AEO 2014 Reference *Low EE Adoption*: AEO 2014 2013 Demand *High EE Adoption*: AEO 2014 High Demand
Renewable Energy Technology Costs	High RE Cost AEO 2014 Reference + Wind Vision Low RE Cost EERE Goals where available	SunShot Scenarios for PV: *Reference*: 62.5% by 2020 going to 75% by 2040 *Low Cost*: 75% by 2020 *High Cost*: 50% by 2020 Wind Vision Scenarios for Wind: *Reference*: WV Median Reduction *Low Cost*: WV High Cost Reduction *High Cost*: WV Low Cost Reduction
Retirements	MJB Planned + Ventyx Lifetimes Extended nuclear lifetime Accelerated coal retirement	Extended Nuclear lifetime: Relicensing to 80 years available Accelerated Coal retirements: 50 yr lifetime if built after 1970 (from 65+) Accelerated retirement if built before 1970
Policy/Regulatory Environment	Current Law	Alternative policies as specific storylines.

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Figure and table from the 2015 Standard Scenarios Report. See http://www.nrel.gov/docs/fy15osti/64072.pdf.

The Standard Scenarios and Annual Technology Baseline products were previously co-released products. In 2016, the projects are now released separately, but are still related. The Standard Scenarios use the ATB as the technology cost and performance inputs.

Annual Technology Baseline (ATB)

- **Product: A populated framework to identify technology-specific cost and performance parameters or other investment decision metrics across a range of resource characteristics, sites, or fuel price assumptions for electricity-generation technologies at present and with projections through 2050. The levelized cost of energy (LCOE) is provided as a summary metric, but is not the primary focus of this work.**
- Accompanying Excel spreadsheet includes all inputs and calculations illustrated on subsequent pages.
- Notes pages that provide additional detail for interpreting information on subsequent pages.
- Product includes:
  - A comparison of input assumptions to recent historic trends; this demonstrates the extent to which model inputs represent current state of technology
  - Projections of future technology cost and performance relative to other published projections; these illustrate results among a variety of sources.
  - Normalization of definitions of variables

While this second edition of ATB continues to focus on utility-scale electricity generation technologies from the perspective of a utility that procures facilities and generates electricity, distribution level PV technologies have been added. Other distribution level technologies and storage will be considered in future editions.

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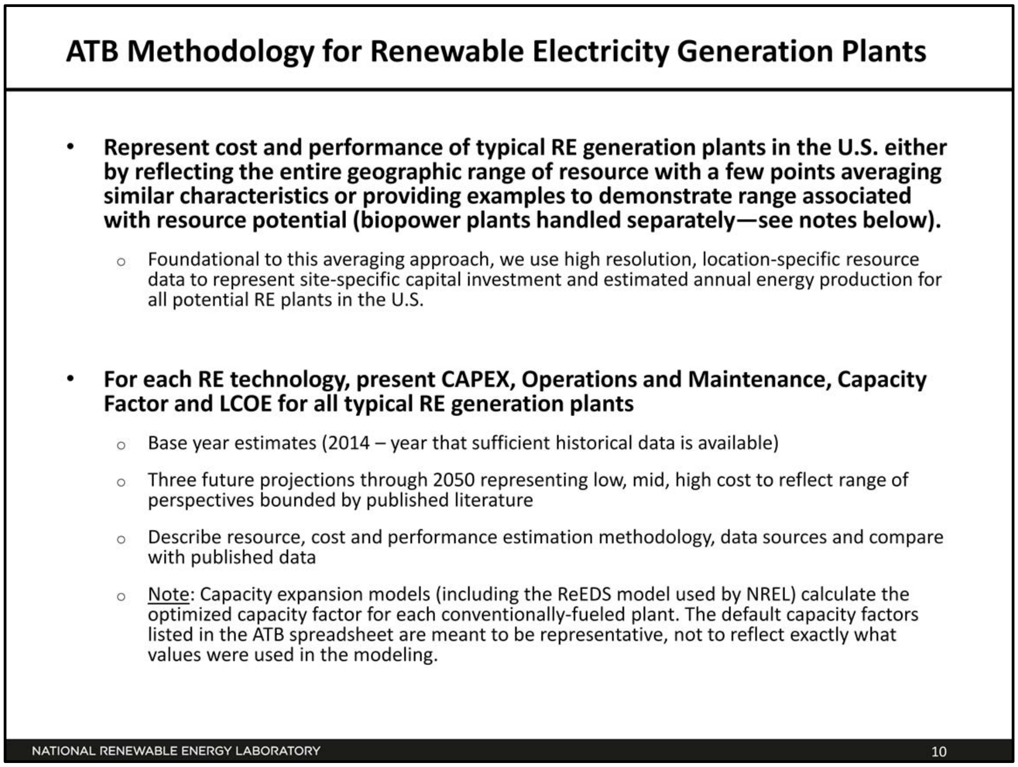
LCOE is used throughout this deck as a summary metric for the various cost and performance inputs of each technology. More information on the LCOE can be found in the “Summary of Technologies” section.



- **ATB Methodology for Fossil and Nuclear Generation Plants**
    - Rely on EIA representation of current year plant cost estimates, and for plant cost projections through 2040 (AEO 2016)
    - Rely on EIA scenarios for fuel price projections through 2040 (AEO 2016)
    - Linearly extrapolate the EIA plant cost estimates from 2040 through 2050
    - Hold the EIA fuel price projections at 2040 levels through 2050

- **ATB Methodology for Biopower Plants**
    - Rely on EIA representation of current year plant cost estimates
    - Rely on EIA representation of future plant cost estimates through 2040 (AEO 2016)
    - Linearly extrapolate the EIA plant cost estimates from 2040 through 2050
    - Represent average biopower feedstock price based on “Billion Ton Study” through 2030
    - Hold the biopower feedstock price at 2030 levels through 2050

References

U.S. Energy Information Administration. (2016). *Annual Energy Outlook 2016 Early Release*. May 2016.

DOE. (2011). *US Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry*. ORNL/TM-2011/224.

Overview of Current Costs in the ATB

Technology	Source
Land-based and Offshore Wind Power Plants	Wind Vision Report (2015), compared to wind market data reports
Utility, Residential, and Commercial PV Plants	Bottoms-up cost modeling from Feldman et al. (2015), compared to PV market data reports
Concentrating Solar Power Plants	Bottoms-up cost modeling from Kurup and Turchi (2015), compared to recent CSP plant (Crescent Dunes) costs
Geothermal Plants	Bottoms-up cost modeling using GETEM
Hydropower Plants	Hydropower Vision Report (2016), cost modeling from O'Connor et al. (2015)
Conventional Plants	Annual Energy Outlook reported costs

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References:
DOE Wind Vision 2015: Wind Cost Appendix H: Table H-4.
Feldman et al (2015) Photovoltaic System Pricing Trends: 2015 Edition. NREL/PR-6A20-64898.
Kurup, P and Turchi, C. (2015), Parabolic Trough Collector Cost Update for the System Advisor Model (SAM). NREL Report No. TP-6A20-65228.
US DOE Geothermal Energy Technology Evaluation Model (GETEM). http://www4.eere.energy.gov/geothermal/projects/1096 and http://www4.eere.energy.gov/geothermal/sites/default/files/documents/mines_getem_peer2013.pdf.
O'Connor, P.W., S.T. DeNeale, D.R. Chalise, A. Maloof (2015). Hydropower Baseline Cost Modeling, Version 2. ORNL/TM-2015/471. Oak Ridge, TN: Oak Ridge National Laboratory.
Electricity Market Module in Assumptions to AEO 2015: Table 8.2.
U.S. Energy Information Administration. (2016). *Annual Energy Outlook 2016 Early Release*. May 2016.

Overview of Future RE Cost Projections

Technology	Source	Rationale
Land-based and Offshore Wind Power Plants, Utility PV Plants, Residential and Commercial PV, Hydropower Plants	High, low, and median values of population from published studies that include cost projections for scenario modeling	Defining ATB High, Mid and Low cost cases as bounding scenarios to published literature provides a broad range of perspective
Concentrating Solar Power (CSP) Plants	High, low, and median values are taken from analysis of the published literature, primarily the SunShot Vision report and new technology pathway analysis in On the Path to SunShot reports.	Defining High, Mid and Low CSP cases in relation to detailed near-term analysis (2020) and relative to published literature provides a range of perspective
Geothermal Plants	Site-specific nature, relative maturity of technology, and lack of existing literature survey lead to assumption of no cost reduction (High, Mid) and application of learning similar to AEO 2015 (Low).	Geothermal Vision study which will likely result in industry developed cost reduction scenarios is underway.

- The ATB relies on future cost projections developed for previous studies.
- This framework provides comparison of cost projections within published literature to illustrate potential differences in perspective. In general projections are within bounds of other perspectives represented in published literature.
- Projections developed independently for each technology using different methods, but initial starting point compared with market data (where available) to provide consistent baseline methodology. Common plant envelope definitions based on Beamon & Leff (2013) contribute to consistent baseline.
- Developing cost and performance projections for electricity generation technologies is difficult. Methods that rely upon engineering-based models are likely to provide insight into potential technology innovations that yield lower cost of energy. Methods that rely upon learning curves in combination with high-level macro-economic assumptions are likely to provide insight into potential rate of adoption of technology innovations. Both methods have strengths and weaknesses in serving the varied interests that seek these types of projections. Approaches that combine methods are likely to provide the greatest transparency and widest application for technology innovation purposes as well as macro-economic purposes.
- High levels of uncertainty are associated with either method. Provision of a range of projections (e.g., low, mid, high) produces scenario modeling results that represent a range of possible outcomes.
- Conventional plant technology costs are from the Annual Energy Outlook 2016 Reference Scenario.

ATB Technologies

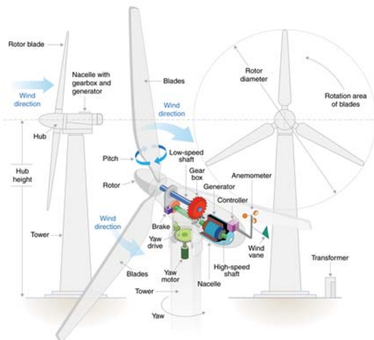
- Land-based Wind Power Plants
- Offshore Wind Power Plants
- Utility-Scale Solar PV Power Plants
- Distributed Residential and Commercial-scale Solar PV
- Concentrating Solar Power Plants
- Geothermal Power Plants: Flash and Binary Organic Rankine Cycle
- Hydropower Plants: Upgrades to Existing Facilities, Powering Non-Powered Dams, and New Stream-reach Development
- Conventional Power Plants: Fossil, Bio, Nuclear

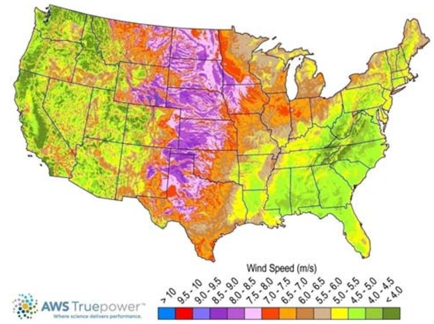
Content of Technology Sections

- **Technology Overview**
  - Resource potential and how CAPEX and/or capacity factor vary with resource
  - Methodology for estimating cost and performance over range of resource conditions
- **Plant CAPEX Definition**
  - Listing of items included in CAPEX estimate
- **CAPEX historic trends, current estimates and future projections**
- **Operations and Maintenance (O&M) costs definition and assumptions**
  - Fixed O&M (FOM), followed by Variable O&M as needed
- **Capacity Factor**: Expected average energy production over technical lifetime of generation plant-historic trends, current estimates and future projections
- **Cost and performance projections methodology**
- **LCOE projections for low, mid, high cost cases with discussion of technology advances that yield future projections**
- **Data sources and references are identified in Notes pages.**

2. Land- based Wind Power Plants

Land-based Wind Overview





Source: NREL, Renewable Electricity Futures

- **Wind resource prevalent throughout the U.S. but concentrated in central states – potential exceeds 10,000 GW**
- **Over 130,000 "areas" for wind plant deployment identified covering over 3.5M square kilometers; potential capacity estimated assuming 3 MW/km2**
- **LCOE calculated for each "area" based on three different wind turbines and long-term average hourly wind profile for each "area"**

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- Total land-based wind potential exceeds 10,000 GW corresponding to over 3.5M square kilometers of potential land area after accounting for standard exclusions such as federally protected areas, urban areas, water, and others. Resource potential has been expanded from approximately 6,000 GW (DOE 2015) by including locations with lower wind speeds to provide more comprehensive coverage of US land areas where future technology may improve economic potential.
- Resource potential represented by over 130,000 distinct "areas" for wind plant deployment covering over 3.5M square kilometers; potential capacity estimated assuming 3 MW/km2 to total over 10,000 GW
- CAPEX based on one of three turbine models associated with the annual average wind speed for each "area".
- CF determined using three normalized wind turbine power curves and hourly wind profile for each "area"
- The majority of land-based wind plants installed in the U.S. range from 50 MW to 100 MW (Wiser and Bolinger, 2014).

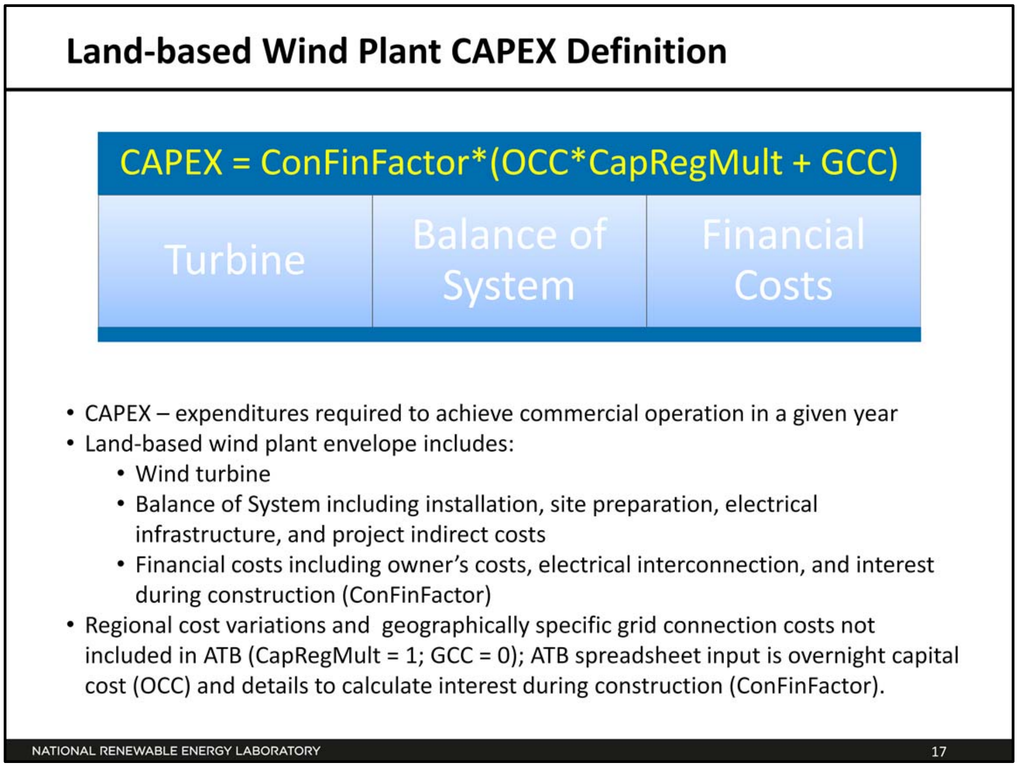
References

- DOE (2015). Wind Vision: A New Era for Wind Power in the United States. 288 pp.; Department of Energy Report No. DOE/GO-102015-4557. http://energy.gov/sites/prod/files/2015/03/f20/wv_full_report.pdf

- Volume 2: Renewable Electricity Generation and Storage Technologies
- Augustine, C.; Bain, R.; Chapman, J.; Denholm, P.; Drury, E.; Hall, D.G.; Lantz, E.; Margolis, R.; Thresher, R.; Sandor, D.; Bishop, N.A.; Brown, S.R.; Cada, G.F.; Felker, F.; Fernandez, S.J.; Goodrich, A.C.; Hagerman, G.; Heath, G.; O'Neil, S.; Paquette, J.; Tegen, S.; Young, K. (2012). Renewable Electricity Generation and Storage Technologies. Vol 2. of Renewable Electricity Futures Study. NREL/TP-6A20-52409-2. Golden, CO: National Renewable Energy Laboratory.

- AWS Truepower. Wind Resource Map. https://www.awstruepower.com/assets/Wind-Resource-Map-UNITED-STATES-11x171.pdf

- Wiser, R.; Bolinger, M.; Barbose, G.; Darghouth, N.; Hoen, B.; Mills, A.; Weaver, S.; Porter, K.; Buckley, M.; Oteri, F.; Tegen, S. (2014). 2013 Wind Technologies Market Report. 96 pp.; NREL Report No. TP-5000-62345; DOE/GO-102014-4459.



- CAPEX in ATB represents wind plant cost in location with no significant logistical challenges or unusual siting conditions similar to the Interior region of the U.S. Regional variants associated with labor rates, material costs, etc. (CapRegMult) are not included.
- CAPEX represents total expenditure required to achieve commercial operation in a given year. Plant envelope defined to include the following (Beamon and Leff, 2013; Moné et al., 2015):
    - Wind turbine supply
    - Balance of System including
        - turbine installation, substructure supply and installation
        - site preparation, installation of underground utilities, access roads, buildings for operations and maintenance
        - electrical infrastructure such as transformers, switchgear and electrical system connecting turbines to each other and to control center
        - project indirect costs including engineering, distributable labor and materials, construction management start up and commissioning, and contractor overhead costs, fees and profit.
    - Financial Costs
        - owner's costs such as development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, property taxes during construction
        - onsite electrical equipment (e.g., switchyard), a nominal-distance spur line (<1 mi), and necessary upgrades at a transmission substation; distance-based spur line cost (GCC) not included in ATB.
        - interest during construction estimated based on 3-year duration accumulated 10%/10%/80% at half-year intervals and 8% interest rate
            - ATB spreadsheet input is Overnight Capital Cost (OCC) and details to calculate interest during construction (ConFinFactor).

Standard Scenarios Model Results

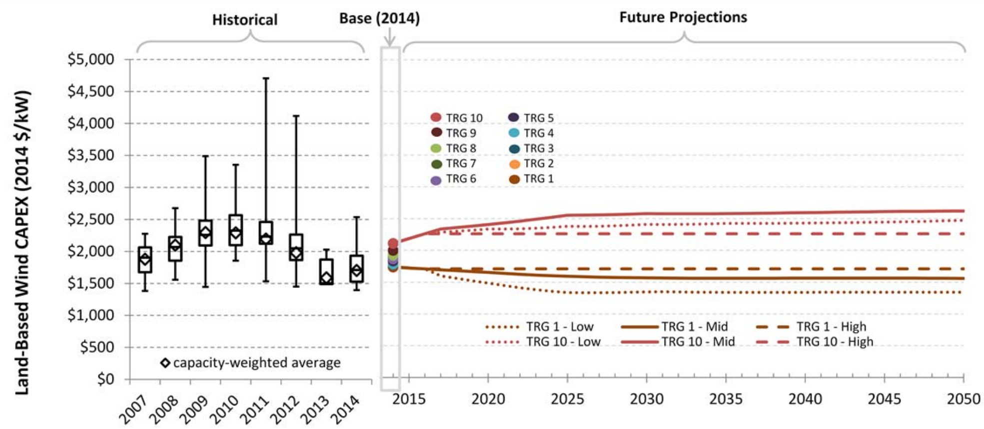
- CAPEX in ATB does not represent regional variants (CapRegMult) associated with labor rates, material costs, etc., but ReEDS does include 134 regional multipliers (Beamon and Leff, 2013)
- ReEDS determines land-based spur line (GCC) uniquely for each of the 130,000 "areas" based on distance and transmission line cost.

References

- Beamon, A.; Leff. M. (2013). EOP III Task 1606, Subtask 3 – Review of Power Plant Cost and Performance Assumptions for NEMS. Prepared by SAIC Energy, Environment & Infrastructure, LLC for the Energy Information Administration, Office of Energy Analysis. http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf

- Moné, C.; Smith, A., Hand, M., Maples, B. (2015). *2013 Cost of Wind Energy Review*. http://www.nrel.gov/docs/fy15osti/63267.pdf

CAPEX Historic Trends, Current Estimates, and Future Projections



Historical data represents CAPEX for plants with Commercial Online Date specified by year.

Projection data represents expected CAPEX for plants with Commercial Online Date specified by Year.

- **CAPEX estimates for 2014 correspond well with market data for plants installed in 2014. Projections reflect continuation of downward trend observed in recent past and anticipated to continue based on preliminary data for 2015 projects.**
- **In the lower wind resource areas represented by TRGs 6-10 CAPEX is likely to grow as future wind turbine technology transitions to new platforms including taller towers, larger rotors and higher machine ratings. In the higher wind resource areas represented by TRGs 1-5 optimization of current wind turbine platforms will lead to lower CAPEX in future years.**
- **TRG = Techno-resource group**

- For illustration in ATB, all potential land-based wind plant “areas” were represented in ten techno-resource groups (TRG). Ten TRG’s were defined by resource potential (GW) and with higher resolution on the highest quality TRGs as these are the most likely sites to be deployed, based on their economics.
- TRG 1 represents the best 100 GW of wind, as determined by LCOE, TRG 2 represents the next best 200 GW, TRG 3 represents the next best 400 GW and TRG 4 represents the next best 800 GW. TRGs 5-9 all represent 1600 GW of resource potential. TRG 10 represents the remaining 1140 GW of available potential. LCOEs associated with this range of resource potential varies from about $47/MWh to $228/MWh in 2014. This representation is based on the approach described in (DOE 2015), but defines the resource in terms of 10 TRGs rather than 5 to improve resolution and accommodate the increased resource potential at lower wind speeds.
- The table below summarizes the annual average wind speed range for each TRG, capacity weighted average wind speed, cost and performance parameters for each TRG, and resource potential in terms of capacity and energy for each TRG

Techno-Resource Group (TRG)	Wind Speed Range (m/s)	Weighted Average Wind Speed (m/s)	Weighted Average CAPEX ($/kW)	Weighted Average OPEX ($/kW/yr)	Weighted Average Net CF (%)	Potential Wind Plant Capacity (GW)	Potential Wind Plant Energy (TWh)
TRG1	7.7 - 13.5	8.8	1737	51	51%	100	411
TRG2	7.5 - 10.4	8.3	1775	51	49%	200	809
TRG3	7.3 - 10.5	8.1	1778	51	48%	400	1610
TRG4	7.1 - 10.1	7.9	1783	51	47%	800	3199
TRG5	6.8 - 9.5	7.5	1833	51	45%	1600	6238
TRG6	61. - 9.4	6.9	1867	51	40%	1600	5567
TRG7	5.3 - 8.3	6.2	1895	51	33%	1600	4561
TRG8	4.7 - 6.6	5.5	1930	51	26%	1600	3513
TRG9	4.1 - 5.7	4.8	1999	51	20%	1600	2597
TRG10	1.6 - 5.1	4.0	2109	51	12%	1140	1099
Total						10,640	29606

- Actual land-based wind plant CAPEX (Wiser and Bolinger, 2014) is shown in box and whiskers format (bar represents median, box represents 25th and 75th percentile, whiskers represent minimum and maximum; diamond represents capacity weighted average) for comparison to ATB current CAPEX estimates and future projections. Wiser & Bolinger (2014) provides statistical representation of CAPEX for about 65% of wind plants installed in the U.S. since 2007
- CAPEX estimates for 2014 correspond well with market data for plants installed in 2014. Projections reflect continuation of downward trend observed in recent past and anticipated to continue based on preliminary data for 2015 projects.
- CAPEX estimates should tend toward the low end of observed cost because no regional impacts or spur line costs are included. These effects are represented in the market data.
- Projections of future wind plant CAPEX were determined based on adjustments to CAPEX, FOM and CF in each year to result in a pre-determined LCOE value. In the lower wind resource areas represented by TRGs 6-10 CAPEX is likely to grow as future wind turbine technology transitions to new platforms including taller towers, larger rotors and higher machine ratings. In the higher wind resource areas represented by TRGs 1-5 optimization of current wind turbine platforms will lead to lower CAPEX.

References

- Wiser, R.; Bolinger, M.; Barbose, G.; Darghouth, N.; Hoen, B.; Mills, A.; Weaver, S.; Porter, K.; Buckley, M.; Oteri, F.; Tegen, S. (2014). 2013 Wind Technologies Market Report. 96 pp.; NREL Report No. TP-5000-62345; DOE/GO-102014-4459.
- Lantz, E.; Wiser, R.; Hand, M. (2012). IEA Wind Task 26: The Past and Future Cost of Wind Energy, Work Package 2. 137 pp.; NREL Report No. TP-6A20-53510.
- Wiser, R.; Lantz, E.; Bolinger, M.; Hand, M. (2012). *Recent Developments in the Levelized Cost of Energy From U.S. Wind Power Projects.* Presentation submitted to IEA Task 26.
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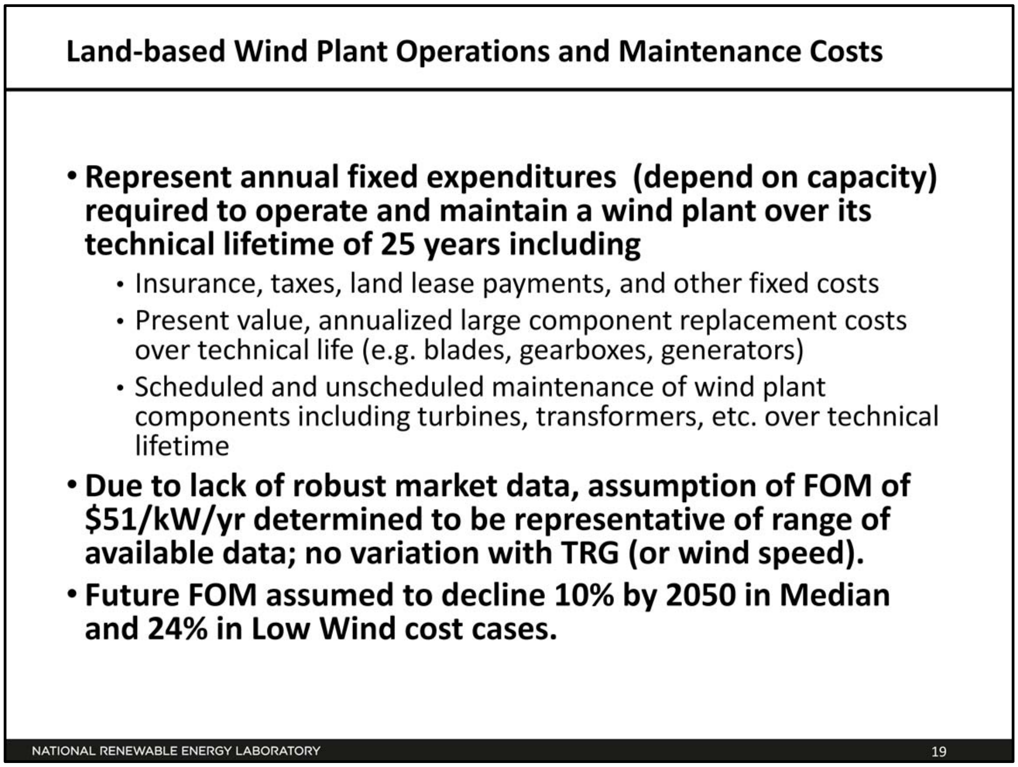

- Represent annual fixed expenditures (depend on capacity) required to operate and maintain a wind plant over its technical lifetime of 25 years including
    - Insurance, taxes, land lease payments, and other fixed costs
    - Present value, annualized large component replacement costs over technical life (e.g. blades, gearboxes, generators)
    - Scheduled and unscheduled maintenance of wind plant components including turbines, transformers, etc. over technical lifetime
- Due to lack of robust market data, assumption of $51/kW/yr determined to be representative of range of available data; no variation with TRG (or wind speed).
- Projections of future wind plant FOM were determined based on adjustments to CAPEX, FOM and CF in each year to result in a pre-determined LCOE value.

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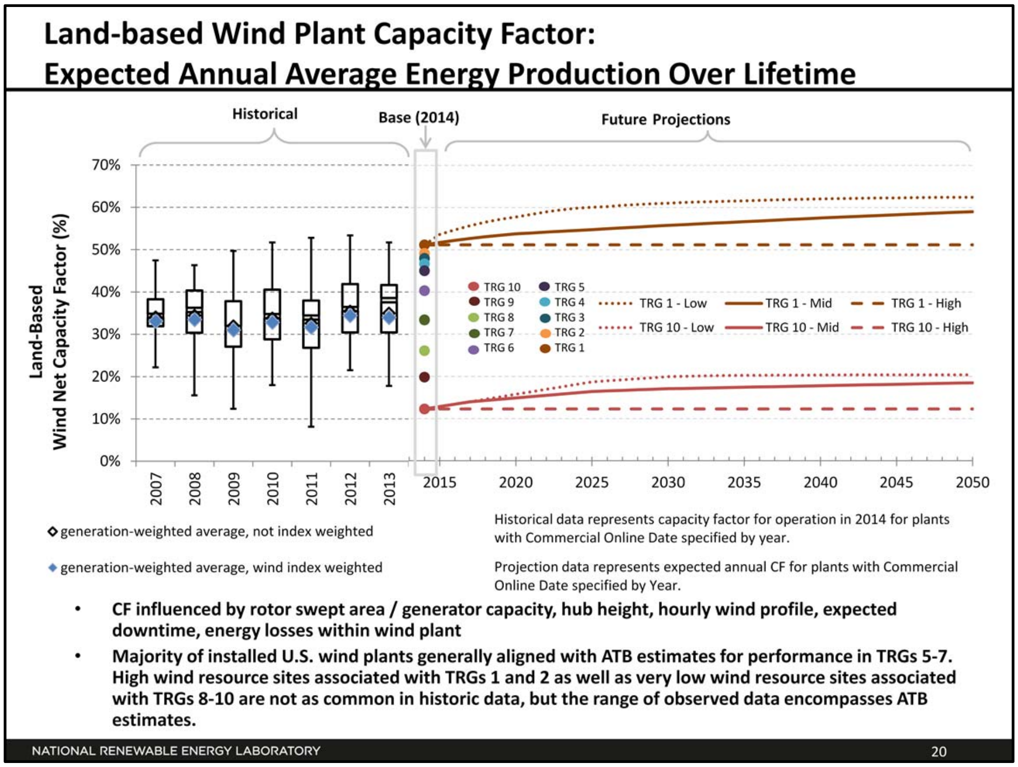
- Wiser, R.; Bolinger, M.; Barbose, G.; Darghouth, N.; Hoen, B.; Mills, A.; Weaver, S.; Porter, K.; Buckley, M.; Oteri, F.; Tegen, S. (2014). 2013 Wind Technologies Market Report. 96 pp.; NREL Report No. TP-5000-62345; DOE/GO-102014-4459.
- DOE (2015). Wind Vision: A New Era for Wind Power in the United States. 288 pp.; Department of Energy Report No. DOE/GO-102015-4557. http://energy.gov/sites/prod/files/2015/03/f20/wv_full_report.pdf

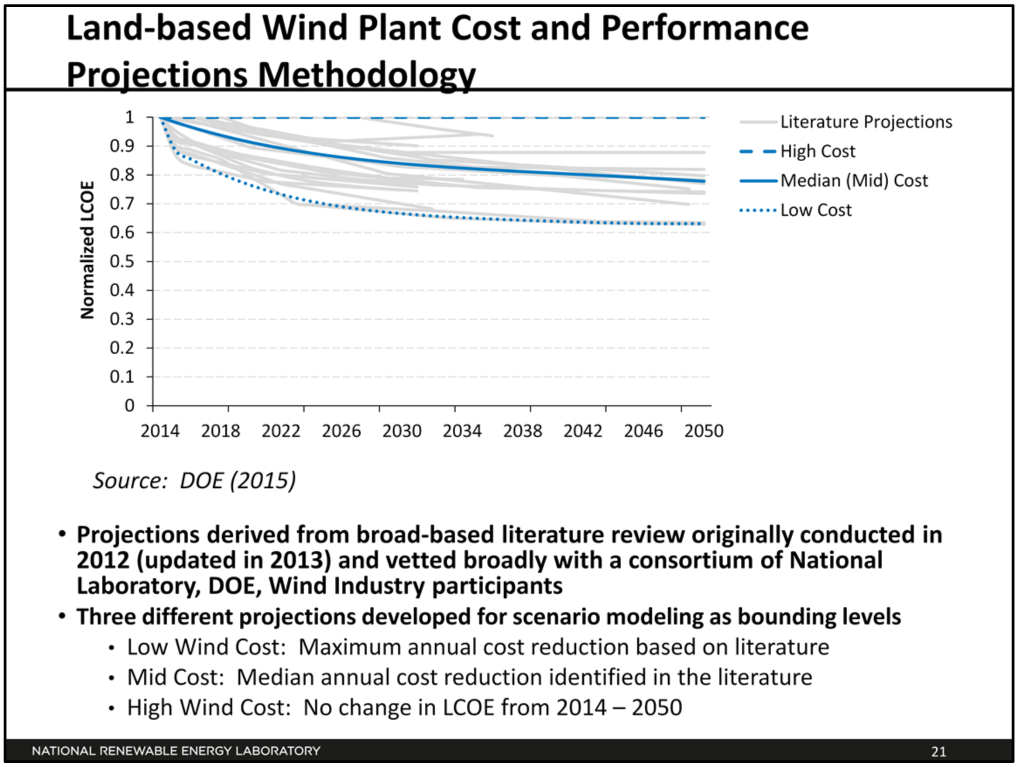


- Capacity factor represents expected annual average energy production divided by annual energy production assuming the plant operates at rated capacity for every hour of the year. Intended to represent long-term average over technical lifetime of plant and does not represent inter-annual variation in energy production.
- CF influenced by rotor swept area / generator capacity, hub height, hourly wind profile, expected downtime, energy losses within wind plant
- CF referenced to 80 m above ground level long-term average hourly wind resource data from AWS Truepower
- For illustration in ATB, all potential land-based wind plant “areas” were represented in ten TRGs. Capacity weighted average CAPEX, CF, and resource potential are shown in earlier slide. (DOE 2015).
- Actual energy production from about 90% of wind plants operating in the U.S. since 2007 (Wiser and Bolinger, 2014) is shown in box and whiskers format for comparison with ATB current estimates and future projections. The historic data illustrates capacity factor for projects operating in 2014 shown by year of commercial online date. A wind index developed by NextEra is used to normalize wind energy production in 2014 relative to historic average wind energy production.
- Majority of installed U.S. wind plants generally aligned with ATB estimates for performance in TRGs 5-7. High wind resource sites associated with TRGs 1-4 as well as very low wind resource sites associated with TRGs 8-10 are not as common in historic data, but the range of observed data encompasses ATB estimates. Projections of capacity factor for plants installed in future years were determined based on adjustments to CAPEX, FOM and CF in each year to result in a pre-determined LCOE value (see next slide for description of methodology).
- Projections for capacity factors implicitly reflect technology innovations such as larger rotors and taller towers that will increase energy capture at the same geographic location without specifying precise tower height and rotor diameter changes.

Standard Scenarios Model Results
- ReEDS output capacity factors for wind and solar-PV can be lower than input capacity factors due to endogenously estimated curtailments determined by scenario constraints.

References

- Wiser, R.; Bolinger, M.; Barbose, G.; Darghouth, N.; Hoen, B.; Mills, A.; Weaver, S.; Porter, K.; Buckley, M.; Oteri, F.; Tegen, S. (2014). 2013 Wind Technologies Market Report. 96 pp.; NREL Report No. TP-5000-62345; DOE/GO-102014-4459.
- Lantz, E.; Wiser, R.; Hand, M. (2012). IEA Wind Task 26: The Past and Future Cost of Wind Energy, Work Package 2. 137 pp.; NREL Report No. TP-6A20-53510.
- Wiser, R.; Lantz, E.; Bolinger, M.; Hand, M. (2012). *Recent Developments in the Levelized Cost of Energy From U.S. Wind Power Projects.* Presentation submitted to IEA Task 26.
- DOE (2015). Wind Vision: A New Era for Wind Power in the United States. 288 pp.; Department of Energy Report No. DOE/GO-102015-4557. http://energy.gov/sites/prod/files/2015/03/f20/wv_full_report.pdf

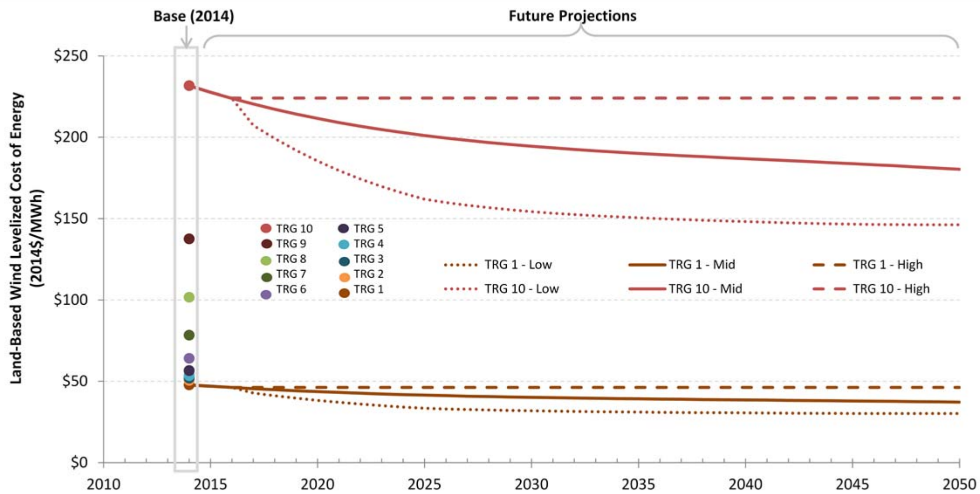


- Projections derived from broad-based literature review (DOE 2015) and vetted with a consortium of National Laboratory, DOE and wind industry experts.
- Projections derived from analysis of more than 20 different projection scenarios from more than 15 independent published studies.
- Literature estimates normalized to a common 2014 starting point in order to focus on projected cost reduction instead of absolute reported costs; range of cost reduction 0% - 40% through 2050.
- Three different projections developed for scenario modeling as bounding levels
    - Low Wind Cost: Maximum annual cost reduction based on literature
    - Mid Cost: Median annual cost reduction identified in the literature
    - High Wind Cost: No change in LCOE from 2014 - 2050
- Cost of energy reductions were implemented as changes to CAPEX, CF, and FOM as illustrated on previous slides.

References

- Lantz, E.; Wiser, R.; Hand, M. (2012). IEA Wind Task 26: The Past and Future Cost of Wind Energy, Work Package 2. 137 pp.; NREL Report No. TP-6A20-53510.
- DOE (2015). Wind Vision: A New Era for Wind Power in the United States. 288 pp.; Department of Energy Report No. DOE/GO-102015-4557. http://energy.gov/sites/prod/files/2015/03/f20/wv_full_report.pdf

Land-based Wind Cost and Performance Projections



- **In general, the degree of adoption of a range of technology innovations distinguishes between the low, mid and high cost cases.**
- **The range of LCOE in 2050 associated with variation in wind resource across the U.S. is $49-224/MWh for the High Cost scenario and $34-146/MWh for the Low Cost scenario.**

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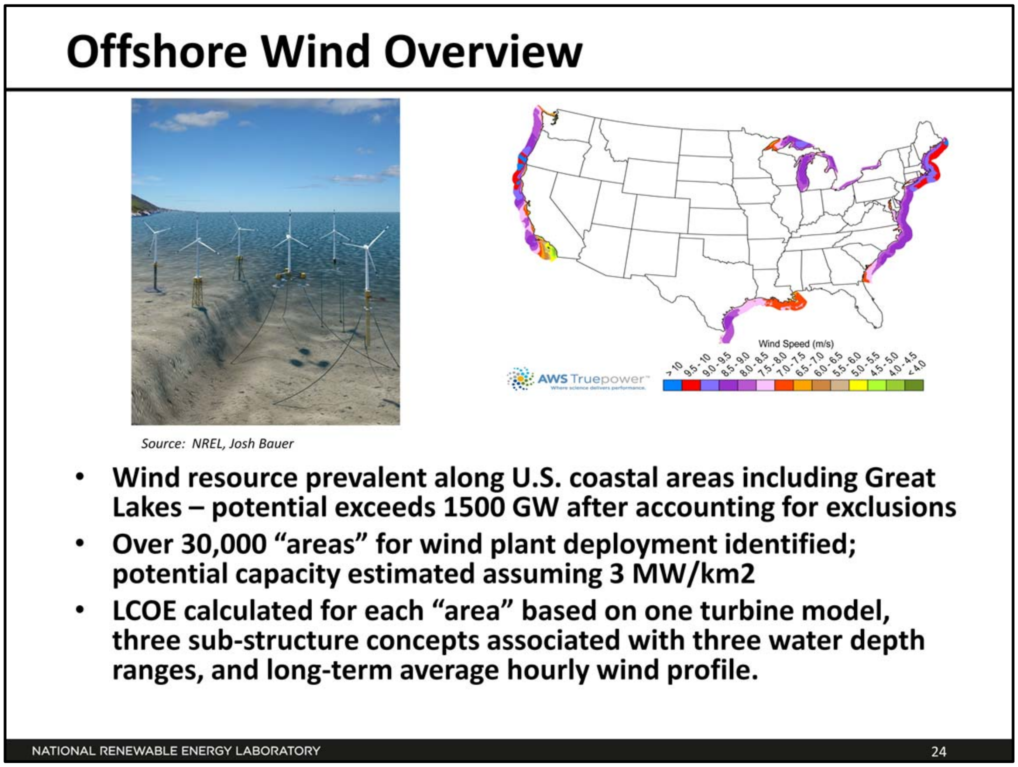
In general, projections represent the following trends, and the degree of adoption distinguishes between Low and Mid Wind Cost scenarios.

- Continued turbine scaling to larger MW turbines with larger rotors such that swept area / MW capacity decreases resulting in high capacity factors for a given location
- Continued diversity of turbine technology where largest rotor diameter turbines tend to be located in lower wind speed sites, but number of turbine options for higher wind speed sites increases.
- Taller towers that result in higher capacity factors for a given site due to wind speed increase with elevation above ground level.
- Improved plant siting and operation to reduce plant level energy losses increasing capacity factor.
- More efficient operation and maintenance procedures combined with more reliable components to reduce annual average FOM costs.
- Continued manufacturing and design efficiencies such that capital cost / kW decreases with larger turbine components.
- Adoption of a wide range of innovative control, design, and material concepts that facilitate the high level trends described above.

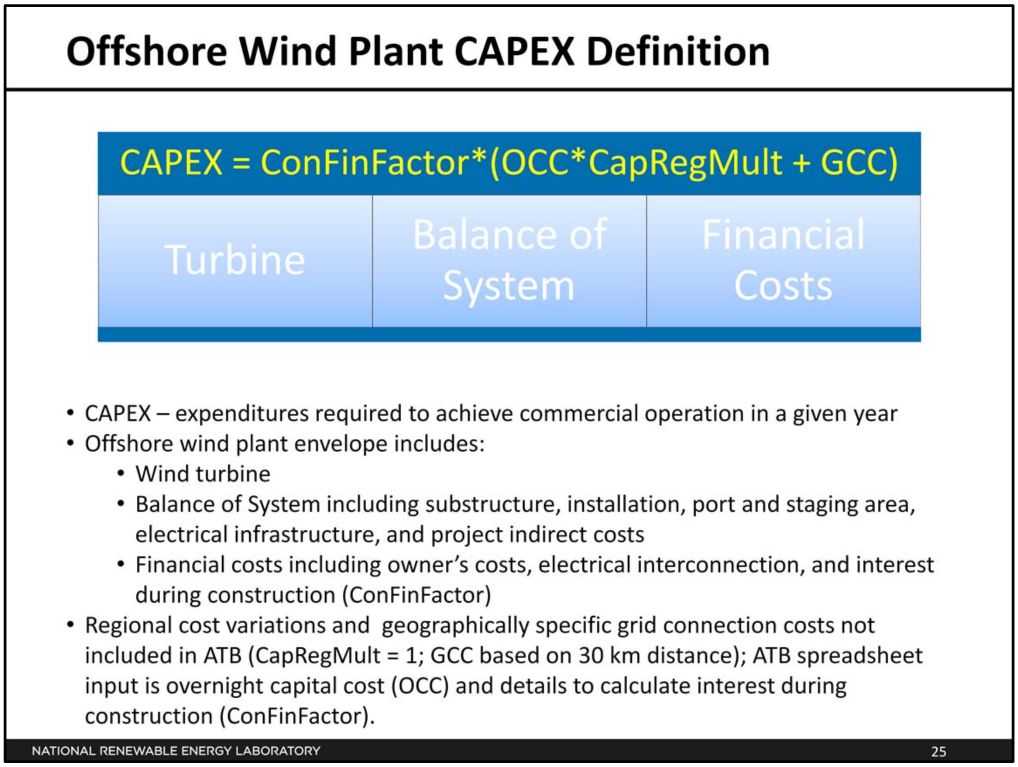
3. Offshore Wind Power Plants



- Wind resource prevalent along U.S. coastal areas including the Great Lakes . Resource potential exceeds 1500 GW (Hand et al., forthcoming) after accounting for exclusions such as marine protected areas, shipping lanes, pipelines, and others.
- Resource potential represented by over 30,000 "areas" for wind plant deployment; potential capacity estimated assuming 3 MW/km2 to total over 15 00 GW.
- CAPEX estimates for each "area" based on one turbine model with three sub-structure concepts associated with three ranges of water depth
- Substructure type reflects water depth
    - Monopile – shallow water from 0-30 m
    - Jacket – mid-depth from 31-60 m
    - Floating – deep water from 61-700 m
- CF estimates determined based on one normalized wind turbine power curve and hourly wind profile for each "area"
- Representative offshore wind plant size is assumed to be about 500 MW (Tegen et al., 2012)

References

- DOE (2015). Wind Vision: A New Era for Wind Power in the United States. 288 pp.; Department of Energy Report No. DOE/GO-102015-4557. http://energy.gov/sites/prod/files/2015/03/f20/wv_full_report.pdf
- Moné, C.; Stehly, T., Maples, B., Settle, E. (2015). *2014 Cost of Wind Energy Review*. http://www.nrel.gov/docs/fy16osti/64281.pdf



- CAPEX in ATB represents typical offshore wind plant sited 30 km from shore which is representative of currently installed European offshore wind plants. CAPEX in ATB does not explicitly represent regional variants associated with labor rates, material costs, etc. or geographically determined spur line costs.
- CAPEX for offshore wind plants in ATB include export cable costs and construction-period transit costs associated with a representative distance of 30 km from shore (GCC based on 30 km distance).
- CAPEX represents total expenditure required to achieve commercial operation in a given year. Plant envelope defined to include the following (Beamon and Leff, 2013; Moné et al., 2015):
  - Wind turbine supply
  - Balance of System including
    - turbine installation, substructure supply and installation
    - site preparation, port and staging area support for delivery, storage, handling, installation of underground utilities
    - electrical infrastructure such as transformers, switchgear and electrical system connecting turbines to each other and to control center
    - project indirect costs including engineering, distributable labor and materials, construction management start up and commissioning, and contractor overhead costs, fees and profit.
  - Financial Costs
    - owner's costs such as development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, property taxes during construction
    - onsite electrical equipment (e.g., switchyard), a nominal-distance spur line (<1 mi), and necessary upgrades at a transmission substation
    - interest during construction estimated based on 3-year duration accumulated 10%/10%/80% at half-year intervals and 8% interest rate
      - ATB spreadsheet input is Overnight Capital Cost (OCC) and details to calculate interest during construction (ConFinFactor).

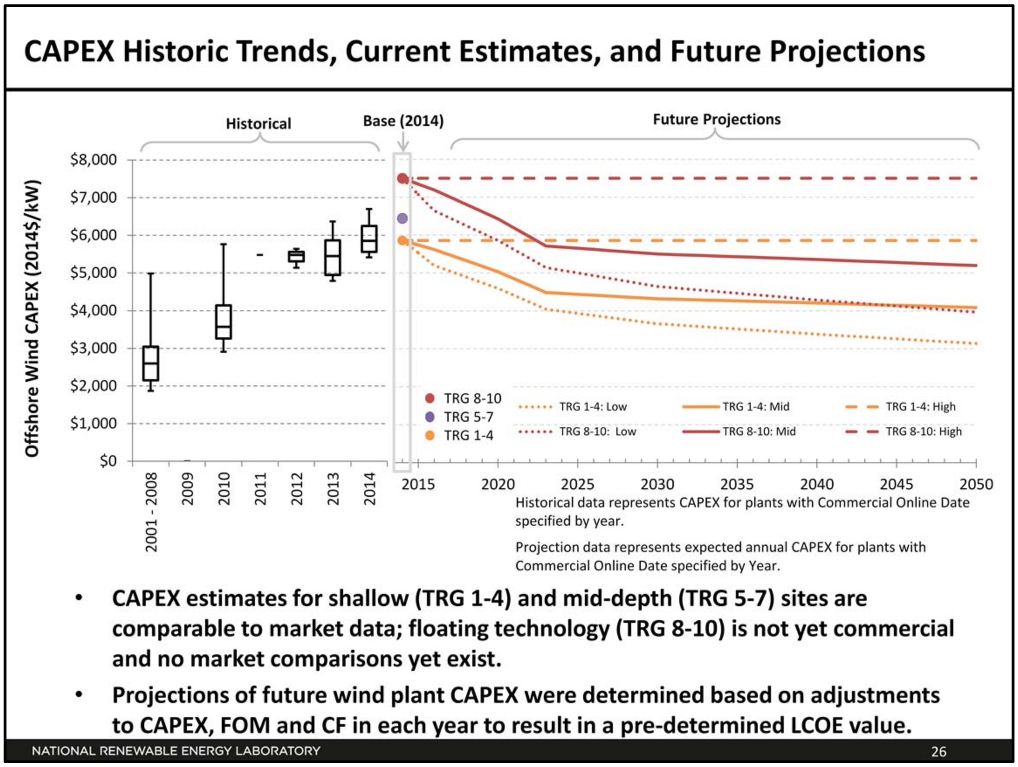
Standard Scenarios Model Results

- CAPEX in ATB does not represent regional variants (CapRegMult) associated with labor rates, material costs, etc., but ReEDS does include 134 regional multipliers (cite SAIC paper).
- ReEDS determines offshore spur line and land-based spur line (GCC) uniquely for each of the 30,000 "areas" based on distance and transmission line cost. ReEDS includes estimates of associated incremental transportation costs during construction with the offshore spur line estimate.

References

Beamon, A.; Leff. M. (2013). EOP III Task 1606, Subtask 3 – Review of Power Plant Cost and Performance Assumptions for NEMS. Prepared by SAIC Energy, Environment & Infrastructure, LLC for the Energy Information Administration, Office of Energy Analysis. http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf

Moné, C.; Smith, A., Hand, M., Maples, B. (2015). *2013 Cost of Wind Energy Review.* http://www.nrel.gov/docs/fy15osti/63267.pdf



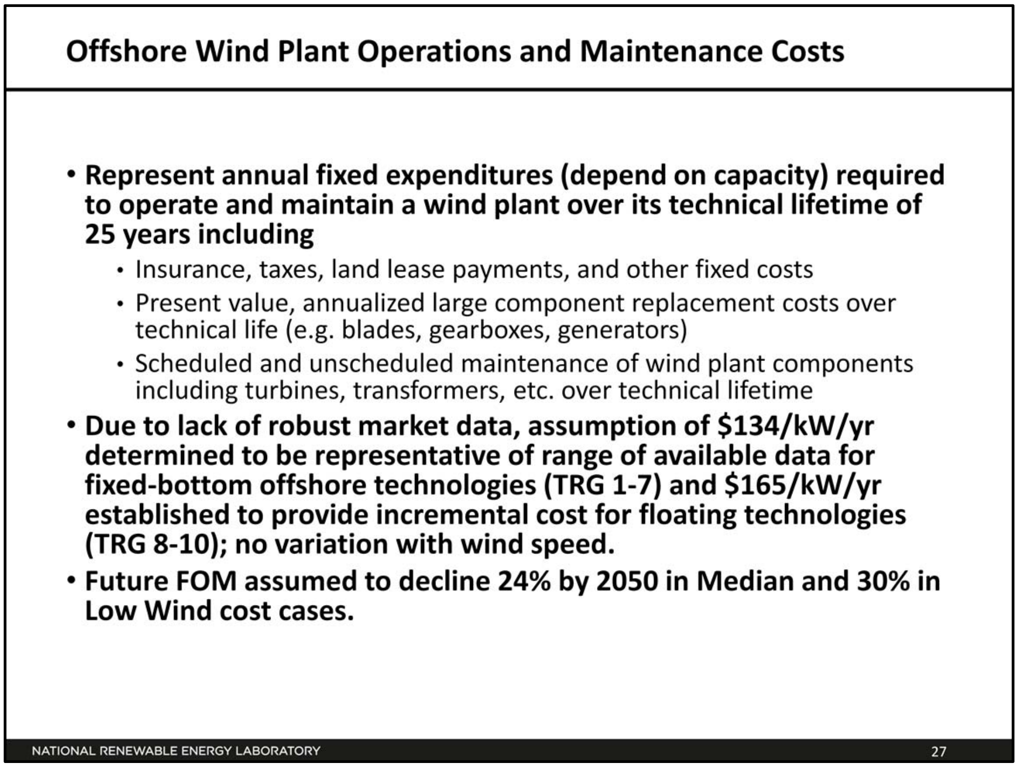
- For illustration in ATB, all potential offshore wind plant "areas" were represented in ten bins. The bins were defined based on water depth and LCOE range. Capacity weighted average wind speed and resource potential are shown below (DOE 2015).

TRG		LCOE Range ($/MWh)	Weighted Average Wind Speed (m/s)	Potential Wind Plant Capacity (GW)	Potential Wind Plant Energy (TWh)
Shallow (<= 30 m)	OSW 1	LCOE <= 172	9.1	11	46
	OSW 2	172< LCOE <= 193	8.5	61	231
	OSW 3	193< LCOE <= 218	8	191	674
	OSW 4	218< LCOE	7.3	165	500
Mid-Depth (31-60 m)	OSW 5	LCOE <= 193	9.1	48	197
	OSW 6	193< LCOE <= 213	8.6	87	338
	OSW 7	213< LCOE	8.4	181	661
Deep (61-700 m)	OSW 8	LCOE <= 218	9.5	82	355
	OSW 9	218< LCOE <= 238	9	184	756
	OSW 10	238< LCOE	8.6	549	2078
Total				1,559	5835

- CAPEX in ATB represents offshore cable cost based on 30 km distance to land.
- Actual and proposed offshore wind plant CAPEX (Smith et al., 2015) are shown in box and whiskers format (bar represents median, box represents 25th and 75th percentile, whiskers represent minimum and maximum for comparison to ATB current CAPEX estimates and future projections.
- Historical CAPEX data represents European projects > 100 MW installed from 2001 to 2014.
- CAPEX estimates for shallow and mid-depth "areas" are comparable to market data; floating technology is not yet commercial and no market comparison data exists.
- Projections of future wind plant CAPEX were determined based on adjustments to CAPEX, FOM and CF in each year to result in a pre-determined LCOE value.

Reference

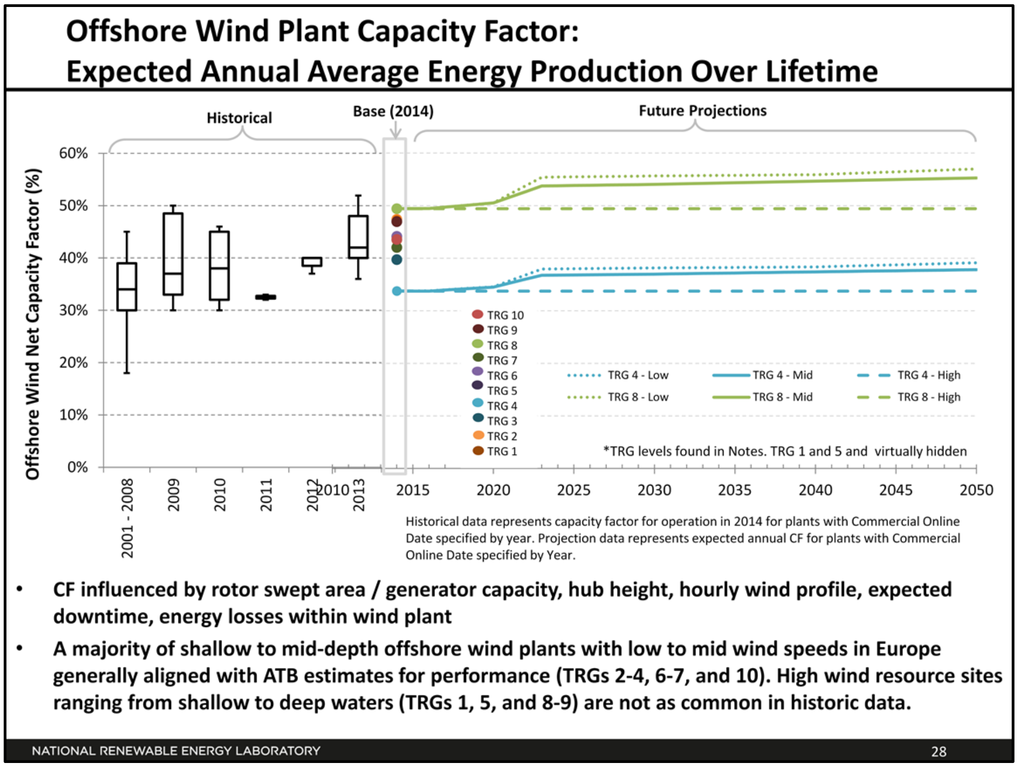
- DOE (2015). Wind Vision: A New Era for Wind Power in the United States. 288 pp.; Department of Energy Report No. DOE/GO-102015-4557. http://energy.gov/sites/prod/files/2015/03/f20/wv_full_report.pdf
- Smith, A., Stehly, T., Musial, W. (2015). 2014-2015 Offshore Wind Technologies Market Report. National Renewable Energy Laboratory Report No. NREL/TP-5000-64283. Available at: http://www.nrel.gov/docs/fy15osti/64283.pdf



- Represent annual fixed expenditures (depend on capacity) required to operate and maintain a wind plant over its technical lifetime of 25 years including
    - Insurance, taxes, land lease payments, and other fixed costs
    - Present value, annualized large component replacement costs over technical life (e.g. blades, gearboxes, generators)
    - Scheduled and unscheduled maintenance of wind plant components including turbines, transformers, etc. over technical lifetime
- Due to lack of robust market data, assumption of $134/kW/yr determined to be representative of range of available data for fixed-bottom offshore technologies (TRG 1-7) and $165/kW/yr established to provide incremental cost for floating technologies (TRG 8-10); no variation with wind speed.
- Projections of future wind plant FOM were determined based on adjustments to CAPEX, FOM and CF in each year to result in a pre-determined LCOE value.

Reference

- Tegen et al. 2012. Cost of Wind Energy Review.
- DOE (2015). Wind Vision: A New Era for Wind Power in the United States. 288 pp.; Department of Energy Report No. DOE/GO-102015-4557. http://energy.gov/sites/prod/files/2015/03/f20/wv_full_report.pdf



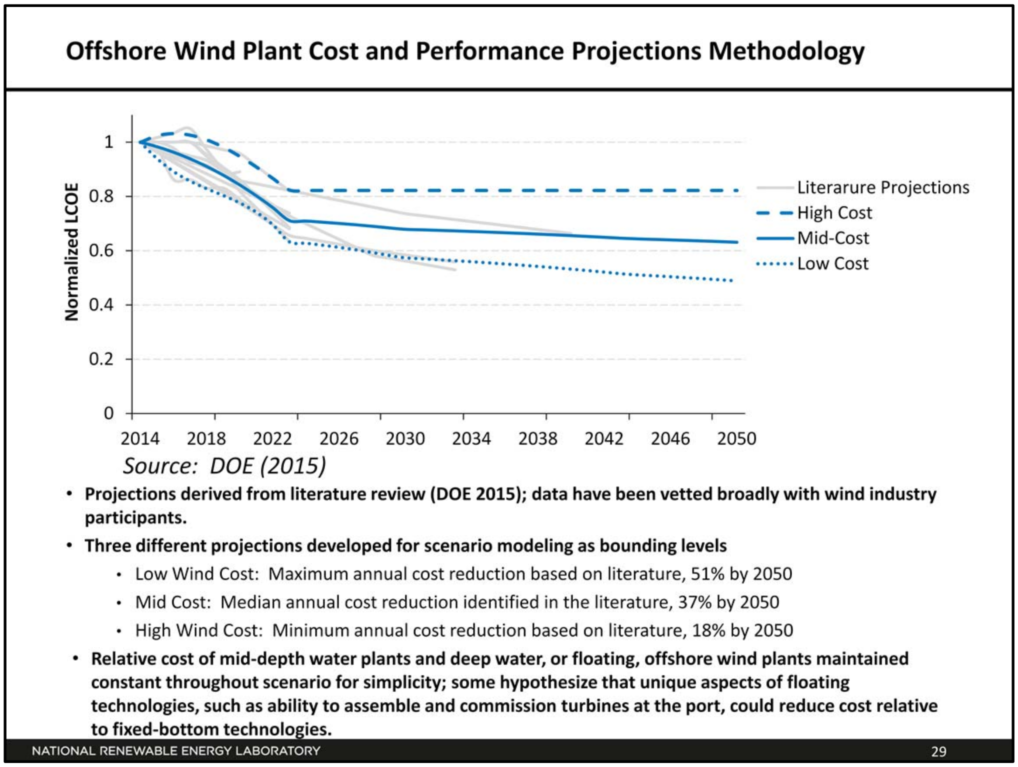
- Capacity factor represents expected annual average energy production divided by annual energy production assuming the plant operates at rated capacity for every hour of the year. Intended to represent long-term average over technical lifetime of plant and does not represent inter-annual variation in energy production.
- CF influenced by rotor swept area / generator capacity, hub height, hourly wind profile, expected downtime, energy losses within wind plant
- CF referenced to 80 m above water surface long-term average hourly wind resource data from AWS Truepower
- For illustration in ATB, all potential offshore wind plant "areas" were represented in ten bins. The bins were defined based on water depth and LCOE ranges. Capacity weighted average CAPEX, CF, and resource potential are shown in earlier slide (DOE 2015).
- Actual energy production from wind plants operating in Europe (Smith et al., 2015) is shown in box and whiskers format for comparison with ATB current estimates and future projections. The historic data illustrates capacity factor for projects operating in 2014 shown by year of commercial online date.
- A majority of shallow to mid-depth offshore wind plants with low to mid wind speeds in Europe are generally aligned with ATB estimates for performance (TRGs 2-4, 6-7, and 10). High wind resource sites ranging from shallow to deep water (TRGs 1, 5, and 8-9) are not as common in historic data.
- Projections of capacity factor for plants installed in future years were determined based on adjustments to CAPEX, FOM and CF in each year to result in a pre-determined LCOE value.

Standard Scenarios Model Results

- ReEDS output capacity factors for wind and solar –PV can be lower than input capacity factors due to endogenously estimated curtailments determined by scenario constraints.

References

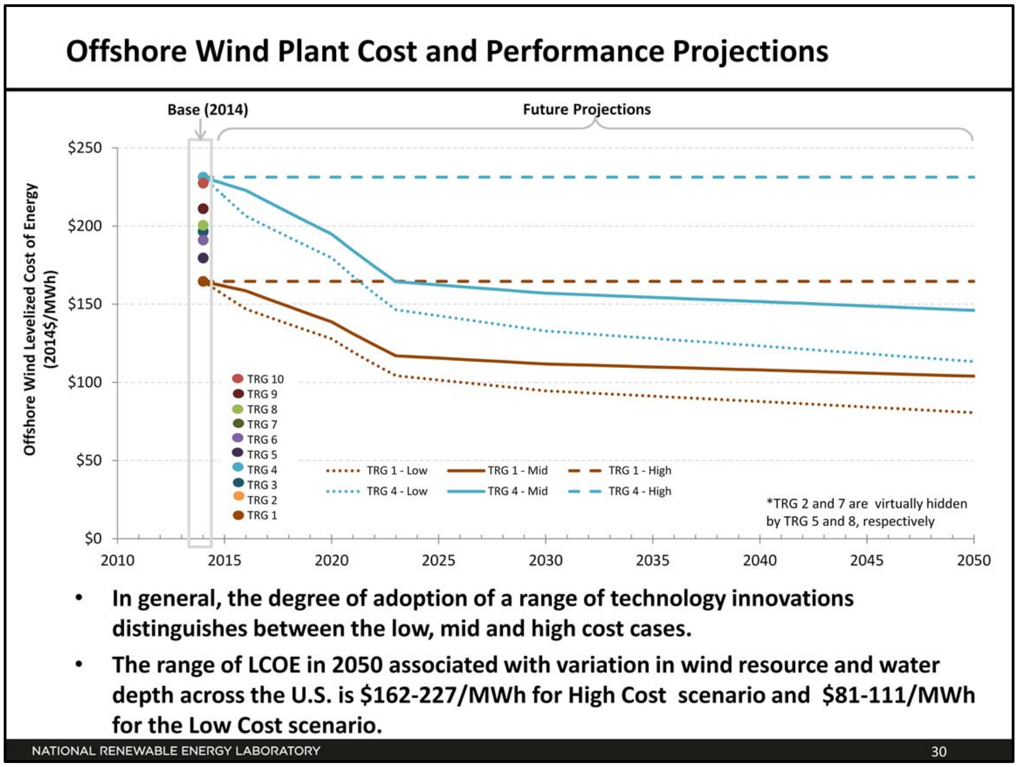
- DOE (2015). Wind Vision: A New Era for Wind Power in the United States. 288 pp.; Department of Energy Report No. DOE/GO-102015-4557. http://energy.gov/sites/prod/files/2015/03/f20/wv_full_report.pdf
- Smith, A., Stehly, T., Musial, W. (2015). 2014-2015 Offshore Wind Technologies Market Report. National Renewable Energy Laboratory Report No. NREL/TP-5000-64283. Available at: http://www.nrel.gov/docs/fy15osti/64283.pdf



- Projections derived from literature review (DOE 2015); data have been vetted broadly with wind industry participants.
- Projections derived from analysis of more than 10 different projection scenarios from 6 independent published studies.
    - Fewer published offshore wind cost and performance projections exist, and most do not extend through 2050.
    - Several pathways for cost reduction tied to specific technical advancements identified by BVG Associates for UK Crown Estate (BVG Associates 2012).
- Literature estimates normalized to a common starting point in order to focus on projected cost reduction; range of cost reduction 20-50% through 2050. Due to lack of study projections extending beyond 2030, LCOE reductions post 2030 are loosely based on progress rates of 0% for High Cost and 5% for Mid and Low Cost.
- Relative cost of mid-depth water plants and deep water, or floating, offshore wind plants maintained constant throughout scenario for simplicity; some hypothesize that unique aspects of floating technologies, such as ability to assemble and commission turbines at the port, could reduce cost relative to fixed-bottom technologies.
- Three different projections developed for scenario modeling as bounding levels
    - Low Wind Cost: Maximum annual cost reduction based on literature, 51% by 2050
    - Mid Cost: Median annual cost reduction identified in the literature, 37% by 2050
    - High Wind Cost: Minimum annual cost reduction based on literature, 18% by 2050
- Cost of energy reductions were implemented as changes to CAPEX, CF, and FOM as illustrated on previous slides.

References

- DOE (2015). Wind Vision: A New Era for Wind Power in the United States. 288 pp.; Department of Energy Report No. DOE/GO-102015-4557. http://energy.gov/sites/prod/files/2015/03/f20/wv_full_report.pdf
- BVG Associates. (2012). *Offshore Wind Cost Reduction Pathways: Technology Work Stream*. The Crown Estate. London. Available at: http://www.thecrownestate.co.uk/media/305086/BVG%20OWCRP%20technology%20work%20stream.pdf

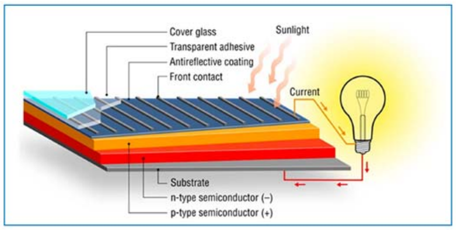


In general, projections represent the following trends, and the degree of adoption distinguishes between Low and Mid and High Wind Cost scenarios.

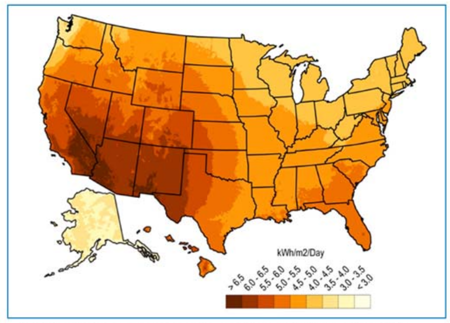
- Continued turbine scaling to larger MW turbines with larger rotors such that swept area / MW capacity decreases resulting in high capacity factors for a given location
- Greater competition for primary components (e.g., turbines, support structure and installation)
- Economy of scale and productivity improvements including mass-production of sub-structure component and optimized installation strategies.
- Improved plant siting and operation to reduce plant level energy losses increasing capacity factor.
- More efficient operation and maintenance procedures combined with more reliable components to reduce annual average FOM costs.
- Adoption of a wide range of innovative control, design, and material concepts that facilitate the high level trends described above.

4. Utility-Scale Solar PV Power Plants

Solar PV Technology Overview



Components of a silicon PV cell (REF Volume 2)



Map of the mean solar resource available to a PV system that is facing south and is tilted at an angle equal to the latitude of the system (REF Volume 2)

- **Flat-plate PV can take advantage of direct and indirect insolation, so PV modules need not directly face and track incident radiation. This gives PV systems a broad geographical application**
- **Solar resources across the United States are mostly good to excellent at about 1,000–2,500 kilowatt-hours (kWh)/square meter (m^2)/year**
- **Representative utility PV systems are one-axis tracking systems with a 1.1 DC-to-AC ratio (or inverter loading ratio)**

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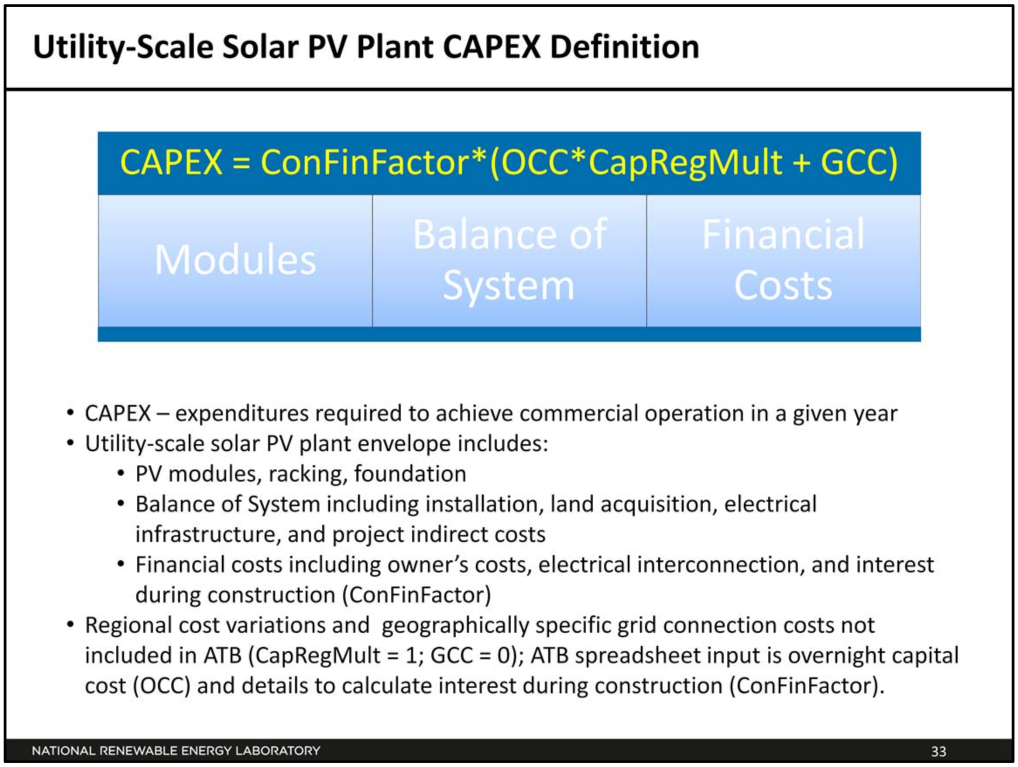
- Solar resources across the United States are mostly good to excellent at about 1,000–2,500 kilowatt-hours (kWh)/square meter (m2)/year. The Southwest is at the top of this range, while only Alaska and part of Washington are at the low end. The range for the 48 contiguous states is about 1,350–2,500 kWh/m2/year. Nationwide, solar resource levels vary by about a factor of two.

- The total U.S. land area suitable for PV is significant and will not limit PV deployment. For example, one estimate suggested that the land area required to supply all end-use electricity in the United States using PV is about 5,500,000 hectares (ha) (13,600,000 acres), which is equivalent to 0.6% of the country's land area or about 22% of the "urban area" footprint (this calculation is based on deployment/land in all 50 states).
- Utility-scale PV plant cost and performance estimated for all available areas based on typical plant cost and hours of sunlight associated with latitude.
    - CAPEX estimated using manufacturing cost models and benchmarked with industry.
    - CF estimated based on hours of sunlight at latitude.

References

Volume 2: Renewable Electricity Generation and Storage Technologies. Augustine, C.; Bain, R.; Chapman, J.; Denholm, P.; Drury, E.; Hall, D.G.; Lantz, E.; Margolis, R.; Thresher, R.; Sandor, D.; Bishop, N.A.; Brown, S.R.; Cada, G.F.; Felker, F.; Fernandez, S.J.; Goodrich, A.C.; Hagerman, G.; Heath, G.; O'Neil, S.; Paquette, J.; Tegen, S.; Young, K. (2012). Renewable Electricity Generation and Storage Technologies. Vol 2. of Renewable Electricity Futures Study. NREL/TP-6A20-52409-2. Golden, CO: National Renewable Energy Laboratory.



- CAPEX in ATB represents solar PV plant cost based on modeled system prices representative of bids issued in the fourth quarter of the previous year.
- CAPEX in ATB does not explicitly represent regional variants associated with labor rates, material costs, etc. or geographically determined spur lines costs.
- CAPEX represents total expenditure required to achieve commercial operation in a given year. Plant envelope defined to include the following based on NREL Solar-PV Manufacturing Cost Model (Feldman et al.) and (Beamon and Leff, 2013):
    - Modules including
        - module supply, power electronics, racking, foundation, AC & DC materials and installation.
    - Balance of System including
        - Land acquisition, site preparation, installation of underground utilities, access roads, fencing, buildings for operations and maintenance.
        - Electrical infrastructure such as transformers, switchgear and electrical system connecting modules to each other and to control center.
        - Project indirect costs including engineering, distributable labor and materials, construction management start up and commissioning, and contractor overhead costs, fees and profit.
    - Financial Costs
        - Owner's costs such as development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, property taxes during construction.
        - Onsite electrical equipment (e.g., switchyard), a nominal-distance spur line (<1 mi), and necessary upgrades at a transmission substation; distance-based spur line cost (GCC) not included in ATB.
        - Interest during construction estimated based on 6-month duration accumulated 100% at half-year intervals and 8% interest rate.
            - ATB spreadsheet input is Overnight Capital Cost (OCC) and details to calculate interest during construction ConFinFactor.

Standard Scenarios Model Results

- CAPEX in ATB does not represent regional variants (CapRegMult) associated with labor rates, material costs, etc., but ReEDS does include 134 regional multipliers (cite SAIC paper).
- CAPEX in ATB does not include geographically determined spur line (GCC) from plant to transmission grid, but ReEDS calculates a unique value for each potential PV plant.

Future ATB Representation

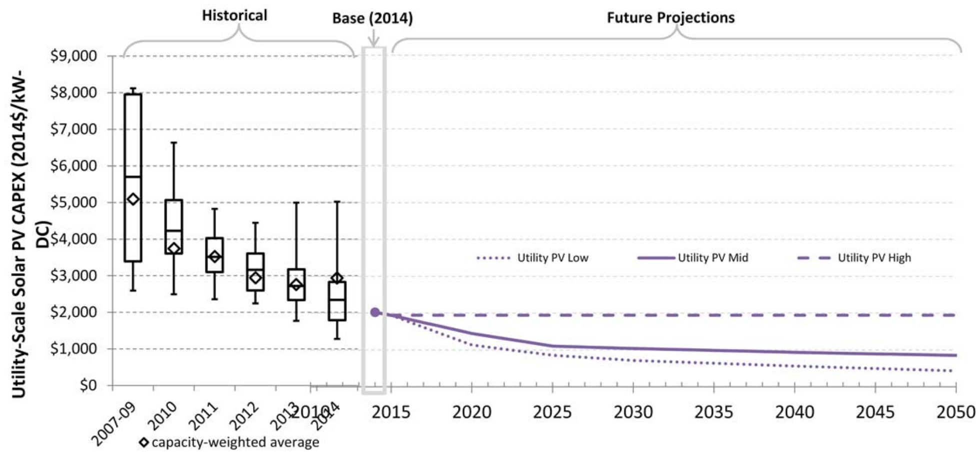
- **Construction period and expenditure schedule may be shortened.**

References

Beamon, A.; Leff. M. (2013). EOP III Task 1606, Subtask 3 – Review of Power Plant Cost and Performance Assumptions for NEMS. Prepared by SAIC Energy, Environment & Infrastructure, LLC for the Energy Information Administration, Office of Energy Analysis. http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf

Feldman, D.; Barbose, G.; Margolis, M.; James, T.; Weaver, S.; Darghouth, N.; Fu, R.; Davidson, C.; Booth, S.; Wiser, R. "Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections 2014 Edition." September 2014. NREL/PR-6A20-62558.

CAPEX Historic Trends, Current Estimates, and Future Projections



- CAPEX estimates for 2015 reflect continued rapid decline supported by analysis of recent PPA pricing (Bolinger and Seel) for projects that will become operational in 2015 and beyond.
- CAPEX estimates should tend toward the low end of reported pricing because no regional impacts, time-lagged system prices, or spur line costs are included.
- Capacity weighted average system prices are higher than 80% of system prices in 2014 due to very large systems, with multi-year constructions schedules, installed.

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- For illustration in ATB a representative utility-scale PV plant is shown. Although the variety of PV technologies varies, typical plant costs can be represented with a single estimate.
- Although the technology market share may shift over time with new developments, the typical plant cost is represented with the projections above.
- Actual utility-scale PV plant CAPEX (Bolinger and Seel, 2015) is shown in box and whiskers format (bar represents median, box represents 20^{th} and 80^{th} percentile, whiskers represent minimum and maximum; diamond represents capacity weighted average) for comparison to ATB current CAPEX estimates and future projections. Bolinger and Seel (2014) provides statistical representation of CAPEX for 87% of all utility-scale PV capacity.
- PV pricing and capacities are quoted in W_{DC} (i.e. module rated capacity) as opposed to other generation technologies which are quoted in W_{AC} (for PV this would correspond to the combined rated capacity of all inverters). This is done because it is the unit that the majority of the PV industry still uses.
- CAPEX estimates should tend toward the low end of observed cost because no regional impacts or spur line costs are included. These effects are represented in the historical market data.
- 2014 & 2015 system prices of $1.98 and $1.90/W are based on modeled pricing for one-axis tracking systems quoted in Q4 2013 and Q1 2015, as reported in Feldman et al. 2015 (adjusted for inflation). This is higher than the $1.80/W and $1.71/W reported in Q1 2015 and Q2 2015 by GTM and SEIA for “Modeled Utility Turnkey One-Axis Tracking PV System Pricing,” as well as the $1.72/W and $1.65/W reported in Q1 2015 and Q2 2015 for “Capacity-Weighted Average Utility PV System Prices.”
- Projections of future utility-scale PV plant CAPEX are based on the a collection of 20 system price projections from 10 separate institutions. To adjust all projections to the ATB’s assumption of single-axis tracking systems, $0.15/W was added to all price projections that assumed fix-tilt tracking technology, and $0.075/W was added for all price projections that did not list whether the technology was fixed-tilt or single-axis tracking. The “high” case assumes that CAPEX pricing remains at current levels. The “low” case represents the minimum estimate in the literature dataset. The “mid” case represents the median estimate in the literature dataset. For the “low” and “mid” cases the values before 2025 include a price adder, representing the difference between the minimum or median US price estimate and the minimum or median price estimate for the entire dataset. This adder decreases on a straight-line between 2015 and 2025. It is assumed after 2025 US prices will be on par with global averages. To account for the temporal variation in price projections the “mid” and “low” cases make estimates every five years through 2030, and every ten years afterwards, with a straight-line change between estimates. In instances in which literature projections did not include all years a straight-line change in price was assumed between any two projected values.

Note: all prices quoted in Euros converted to USD (1 € = $1.25); all prices quoted in W_{AC} converted to W_{DC} (1 W_{AC}=1.2 W_{DC}).

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Utility-scale Solar PV Plant Operations and Maintenance Costs

- **Represent annual expenditures required to operate and maintain a solar PV plant over its technical lifetime of 30 years including:**
  - Insurance, legal and administrative fees, and other fixed costs
  - Present value, annualized large component replacement costs over technical life (e.g., inverters)
  - Scheduled and unscheduled maintenance of solar PV plants, transformers, etc. over technical lifetime
- **FOM assumed to be \$17/kW/yr based on industry data.**
- **Future FOM assumed to decline by 55% by 2020 in Low and by 2025 in Mid.**

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- Represent annual expenditures required to operate and maintain a solar PV plant over its technical lifetime of 30 years including:
  - Insurance, legal and administrative fees, and other fixed costs.
  - Present value, annualized large component replacement costs over technical life (e.g., inverters).
  - Scheduled and unscheduled maintenance of solar PV plants, transformers, etc. over technical lifetime.

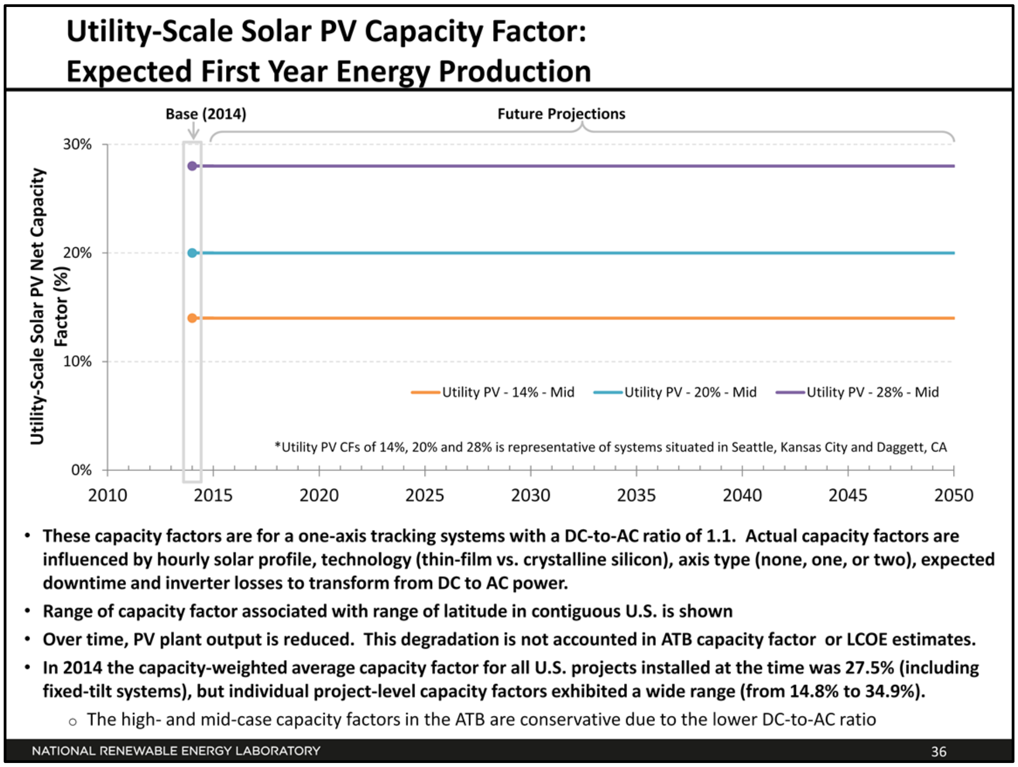
FOM of \$16.7/kW_{DC}/yr based on Bolinger and Seel (2015) in which they state that “PV O&M costs appear to have been in the neighborhood of
\$20/kW_{AC}-year, or \$10/MWh, in 2014.” AC was converted into DC by dividing by 1.2. A wide range in reported price exists in the marketplace, in part depending on what maintenance practices exist for a particular system. These cost categories include: asset management (including compliance and reporting for incentive payments), different insurance products, site security, cleaning, vegetation removal, and failure of components. Not all of these practices are performed for each system; additionally, some factors are dependent on the quality of the parts and construction. NREL analysts estimate that O&M costs can range between \$0 - \$40/kW_{DC}/yr.

- Typical projects perform some, but not necessarily all, of the following O&M procedures:
  1) Inverter replacement at 15 years
  2) General maintenance (including cleaning and vegetation removal)
  3) Site security
  3) Legal and administrative fees
  4) Insurance
  5) Property taxes

References

US Department of Energy, 2012. SunShot Vision Study: February 2012. NREL Report No. BK5200-47927

Bolinger, M.; Seel, J. (2015). *Utility-Scale Solar 2014: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States*. Berkeley, CA: Lawrence Berkeley National Laboratory.



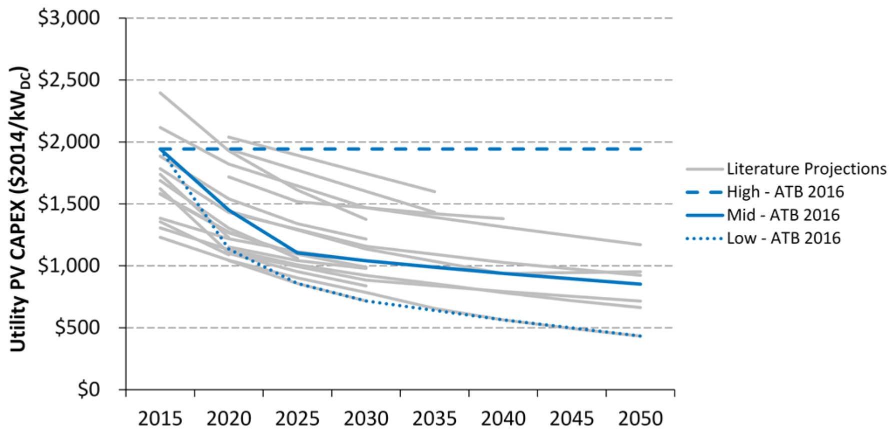
- Capacity factor represents expected annual average energy production (kWh_{AC}) divided by annual energy production assuming the plant operates at rated DC capacity for every hour of the year. It is intended to represent long-term average over technical lifetime of plant. Other technologies' capacity factors are represented in exclusively AC units, however because PV pricing in this presentation is represented in $\$/W_{DC}$ PV system capacity is a DC rating. PV system inverters, which convert DC energy/power to AC energy/power, have AC capacity ratings; therefore the capacity of a PV system is also rated in MW_{AC}, or the aggregation of all inverters' rated capacities. A PV system's capacity factor can also be represented using exclusively AC units, which is typically a higher number than the DC capacity factor (PV systems' DC ratings are typically higher than their AC rating, therefore the capacity factor calculated using a DC capacity rating has a higher denominator).
- Capacity factor influenced by hourly solar profile, technology (thin-film versus crystalline silicon), axis type (none, one, or two), expected downtime and inverter losses to transform from DC to AC power.
- For illustration in ATB, range of capacity factor associated with range of latitude in contiguous U.S. is shown.
- Over time, PV plant output is reduced. This degradation is not accounted in ATB capacity factor estimates. It is typically represented by a reduced plant capacity in the future rather than a change in annual output.
- Projections of capacity factor for plants installed in future years are unchanged from current year. Solar-PV plants have very little downtime and inverter efficiency is already optimized.
- Given the historic reported capacity factors by systems installed in the U.S., these values likely represent a conservative estimate of system production. Part of this is due to differences in inverter loading ratios (ILR, also called DC-to-AC ratio), which can increase production, but also increase cost ($\$/W_{DC}$). That said, in 2014 the cumulative PV capacity factor for low-, mid-, and high-insolation regions, for tracking systems with a mid-level ILR (1.2-1.275) were 21.5%, 29.2%, and 31% respectively – significantly higher than the 14%, 20%, and 28% used in this analysis.

Standard Scenarios Model Results
- Assumed annual degradation of 0.5% is represented in NPV calculation in ReEDS.
- ReEDS output capacity factors for wind and solar-PV can be lower than input capacity factors due to endogenously estimated curtailments determined by scenario constraints.

References:
National Renewable Energy Laboratory. Regional Energy Deployment System (ReEDS).

Bolinger, M.; Seel, J. (2015). *Utility-Scale Solar 2014: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States*. Berkeley, CA: Lawrence Berkeley National Laboratory. September 2015.

Utility-scale PV Plant Cost and Performance Projections Methodology



- **20 global and US system price projections over time, from 10 separate institutions**
- **Many of the global projections are weighted heavily towards western countries (e.g. Europe, Japan, U.S.) and in the long-term, U.S. should follow global trends – many institutions used one system price for all countries**

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- Projections of future utility-scale PV plant CAPEX are based on the a collection of 20 system price projections from 10 separate institutions. To adjust all projections to the ATB's assumption of single-axis tracking systems, $0.15/W was added to all price projections that assumed fix-tilt tracking technology, and $0.075/W was added for all price projections that did not list whether the technology was fixed-tilt or single-axis tracking. The "high" case assumes that CAPEX pricing remains at current levels. The "low" case represents the minimum estimate in the dataset. The "mid" case represents the median estimate in the dataset. For the "low" and "mid" cases the values before 2025 include a price adder, representing the difference between the minimum or median US price estimate and the minimum or median price estimate for the entire dataset. This adder decreases on a straight-line between 2015 and 2025. It is assumed after 2025 US prices will be on par with the median of all (U.S. + global) price projections. To account for the temporal variation in price projections the "mid" and "low" cases make estimates every five years through 2030, and every ten years afterwards, with a straight-line change between estimates.

Note: all prices quoted in Euros converted to USD (1 € = $1.25); all prices quoted in W_{AC} converted to W_{DC} (1 W_{AC}=1.2 W_{DC}). The maximum value was kept constant after its last year of projection; in instances in which literature projections did not include all years a straight-line change in price was assumed between any two projected values.

Capacity factors are assumed to not increase over time. All PV system efficiency improvements are assumed to result in capital cost reductions rather than capacity factor improvements.

References

US Department of Energy, 2012. SunShot Vision Study: February 2012. NREL Report No. BK5200-47927

Projections:

Agora Energiewende. (2015). *Current and Future Cost of Solar Photovoltaics*. February 2015.

Arnulf Jäger-Waldau, et al. (2014). *ETRI 2014: Energy Technology Reference Indicator, projections for 2010-2050*. European Commission: JRC Science and Policy Reports.

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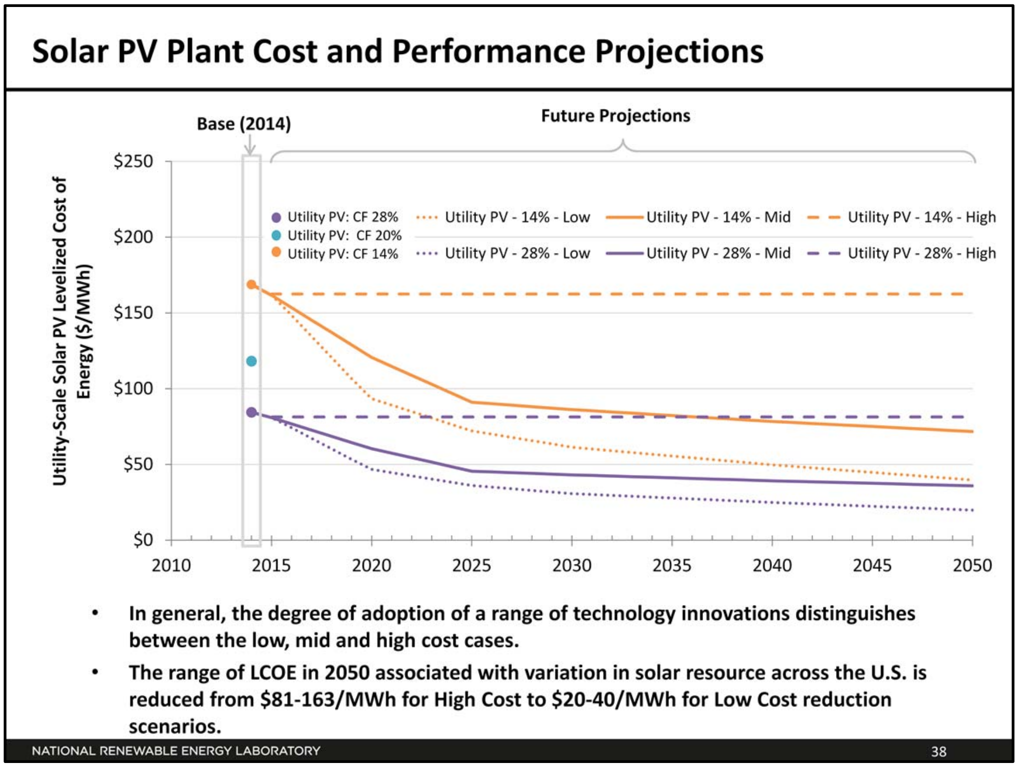
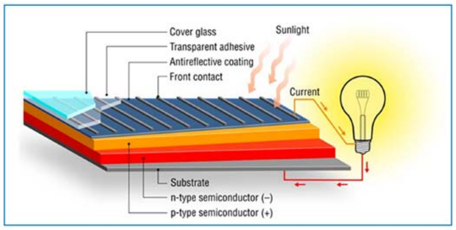


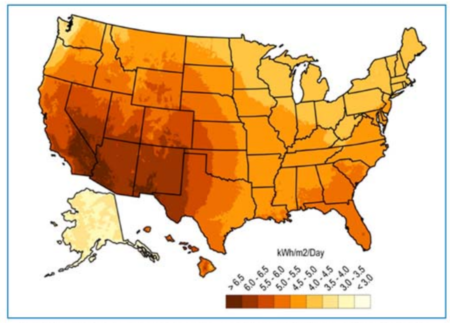
- In general, projections represent the following trends to reduce CAPEX and FOM. The degree of adoption distinguishes between Low, Mid, and High PV Cost scenarios.
- Modules
  - Increased module efficiencies and increased production-line throughput to decrease CAPEX (overhead costs on a per-kilowatt will go down if efficiency and throughput improvement are realized).
  - Reduced wafer thickness or the thickness of thin-film semiconductor layers.
  - Development of new semiconductor materials.
  - Thin-film (CdTE and CIGS).
  - Developing larger manufacturing facilities in low-cost regions.
- Balance of System
  - Increased module efficiency, reducing the size of the installation.
  - Development of racking systems that enhance energy production or require less robust engineering.
  - Integration of racking or mounting components in modules.
  - Reduction of supply chain complexity and cost.
    - Create standard packages system design.
    - Improve supply chains for BOS components in modules.
    - Create standard packaged system designs.
    - Improve supply chains for BOS components.
  - Improved power electronics
    - Improve inverter prices and performance, possibly by integrating micro-inverters.
  - Decreased installation costs and margins
    - Reduction of supply chain margins (e.g., profit and overhead charged by suppliers, manufacturer, distributors, and retailers); this will likely occur naturally as the U.S. PV industry grows and matures.
    - Streamlining of installation practices through improved workforce development and training, and developing standardized PV hardware.
    - Expansion of access to a range of innovative financing approaches and business models.
    - Development of best practices for permitting interconnection, and PV installation such as subdivision regulations, new construction guidelines, and design requirements.
- FOM cost reduction represents optimized O&M strategies, reduced component replacement costs and lower frequency of component replacement.

5. Distributed Residential Solar PV

Distributed Residential Solar PV Technology Overview



Components of a silicon PV cell (REF Volume 2



Map of the mean solar resource available to a fixed axis PV system that is facing south and is tilted at an angle equal to the latitude of the system (REF Volume 2)

- **Flat-plate PV can take advantage of direct and indirect insolation, so PV modules need not directly face and track incident radiation. This gives PV systems a broad geographical application especially for Residential PV systems**

- **Solar resources across the United States are mostly good to excellent at about 1,000–2,500 kilowatt-hours (kWh)/square meter (m^2)/year**
- **Residential PV systems have been modelled for a 5.0 kW_{DC} with a fixed tilt (25^o) roof mount system**

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- Solar resources across the United States are mostly good to excellent at about 1000 – 2,500 kilowatt-hours (kWh)/square meter (m2)/year. The Southwest is at the top of this range, while only Alaska and part of Washington are at the low end. The range for the 48 contiguous states is about 1,350–2,500 kWh/m2/year. Nationwide, solar resource levels vary by about a factor of two.

- Distributed-scale PV is assumed to be configured as a fixed-axis, roof-mounted system. Compared to Utility-Scale PV, this reduces both the potential capacity factor and amount of land (roof space) that is available for development. A recent study of rooftop PV technical potential estimated that as much as 731 GW (926 TWh/yr) of potential exists for small buildings (< 5,000 m^2 footprint) and 386 GW (506 TWh/yr) for medium (5,000 – 25,000 m^2) and large buildings (>25,000 m^2) (Gagnon et al 2016).

- Distributed-scale PV system cost and performance estimated for all available areas based on typical system cost and hours of sunlight associated with latitude.
    - CAPEX estimated using manufacturing cost models and benchmarked with industry.
    - CF estimated based on low, mid, and high resource areas to represents a range of potential generation.
- Residential-scale PV plants installed in the U.S. are represented by system size of 5 kW (US DOE, 2012).

References

Volume 2: Renewable Electricity Generation and Storage Technologies. Augustine, C.; Bain, R.; Chapman, J.; Denholm, P.; Drury, E.; Hall, D.G.; Lantz, E.; Margolis, R.; Thresher, R.; Sandor, D.; Bishop, N.A.; Brown, S.R.; Cada, G.F.; Felker, F.; Fernandez, S.J.; Goodrich, A.C.; Hagerman, G.; Heath, G.; O'Neil, S.; Paquette, J.; Tegen, S.; Young, K. (2012). Renewable Electricity Generation and Storage Technologies. Vol 2. of Renewable Electricity Futures Study. NREL/TP-6A20-52409-2. Golden, CO: National Renewable Energy Laboratory.

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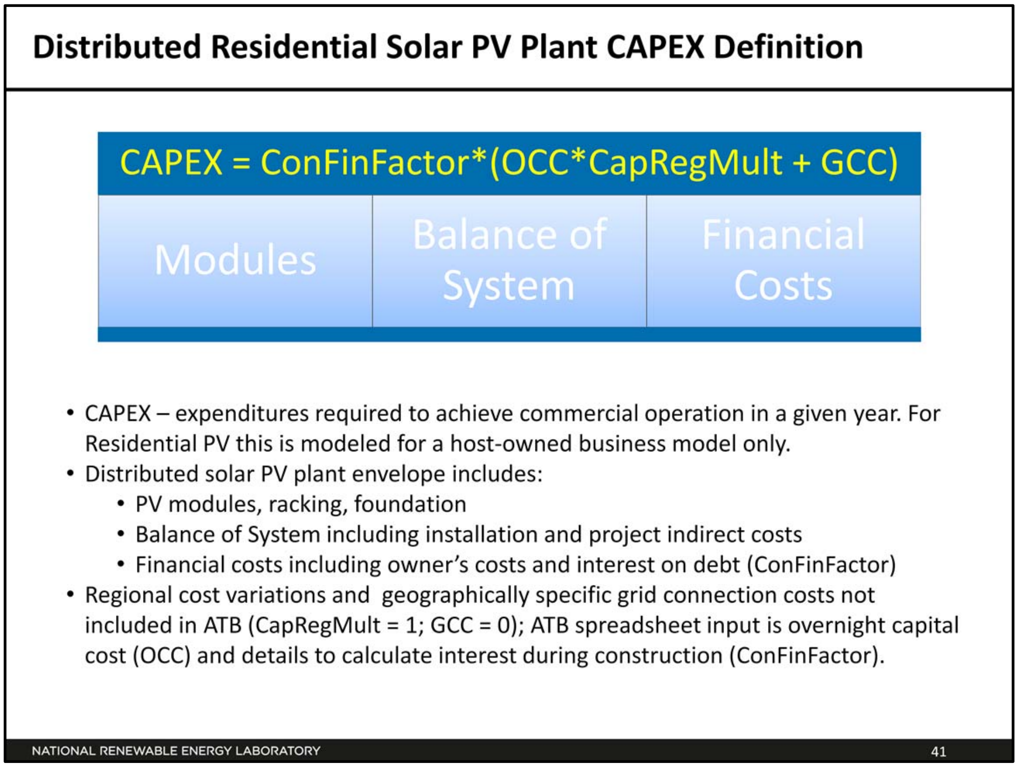
Pieter Gagnon, Robert Margolis, Jennifer Melius, Caleb Phillips, Ryan Elmore. (2016). Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment. NREL Report No. 6A20-65298



- CAPEX in ATB for 2014-15 represent the bottom-up NREL price benchmark, as reported in Woodhouse et al. 2016 and Feldman et al. 2015.; projections post-2015 are based on a collection of 10 system price projections from 5 separate institutions. The "high" case assumes that CAPEX pricing remains at current levels. The " low" case represents the minimum estimate in the dataset. The "mid" case represents the median estimate in the dataset , however the values before 2025 include a price adder, representing the difference between the median US 2015 price estimate and the median 2015 price estimate for the entire dataset. This adder decreases on a straight-line between 2020 and 2025. It is assumed after 2025 US prices will be on par with global averages. To account for the temporal variation in price projections the "mid" and "low" cases make estimates every five years through 2030 , and every ten years afterwards, with a straight-line change between estimates. In instances in which analyst projections did not include all years a straight-line change in price was assumed between any two projected values.

- CAPEX in ATB does not explicitly represent regional variants associated with labor rates, material costs, etc. or geographically determined spur lines costs. See slide below for complete details.
- CAPEX represents total expenditure required to achieve operation in a given year. Plant envelope defined to include the following based on NREL Solar-PV Manufacturing Cost Model (Feldman et al. 2015) and (Beamon and Leff, 2013):
  - Modules including
    - module supply, power electronics, racking, foundation, AC & DC materials and installation.
  - Balance of System including
    - Land acquisition, site preparation, installation of underground utilities, access roads, fencing, buildings for operations and maintenance.
    - Electrical infrastructure such as transformers, switchgear and electrical system connecting modules to each other and to control center.
    - Project indirect costs including engineering, distributable labor and materials, construction management start up and commissioning, and contractor overhead costs, fees and profit.
  - Financial Costs
    - Owner's costs such as development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, property taxes during construction.
    - Onsite electrical equipment (e.g., switchyard), a nominal-distance spur line (<1 mi), and necessary upgrades at a transmission substation; distance-based spur line cost (GCC) not included in ATB.
    - Interest during construction estimated based on 1-year duration accumulated 100% at half-year intervals and 8% interest rate.
      - ATB spreadsheet input is Overnight Capital Cost (OCC) and details to calculate interest during construction ConFinFactor.

Standard Scenarios Model Results

- CAPEX in ATB does not represent regional variants (CapRegMult) associated with labor rates, material costs, etc., but dSolar does include 134 regional multipliers (EIA 2013).

References

Beamon, A.; Leff. M. (2013). EOP III Task 1606, Subtask 3 – Review of Power Plant Cost and Performance Assumptions for NEMS. Prepared by SAIC Energy, Environment & Infrastructure, LLC for the Energy Information Administration, Office of Energy Analysis. http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf

EIA 2013. *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants.* Washington, DC: U.S. DOE Energy Information Administration. http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf.

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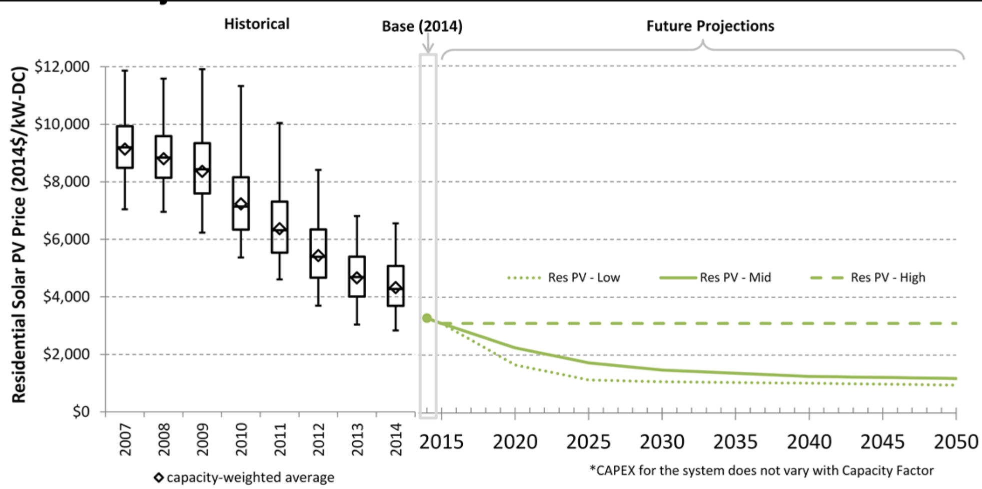
CAPEX (Residential PV) Historic Trends, Current Estimates, and Future Projections



- CAPEX estimates for 2015 reflect continued rapid decline in pricing supported by analysis of recent system cost and pricing (GTM/SEIA) for projects that became operational in 2015.
- CAPEX estimates should tend toward the low end of reported pricing because of the tendency of reported data to reflect short-term market distortions and reporting methods.

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- For illustration in ATB a representative residential-scale PV plant is shown. Although the variety of PV technologies varies, typical plant costs can be represented with a single estimate.
- Although the technology market share may shift over time with new developments, the typical plant cost is represented with the projections above.
- Actual residential PV plant CAPEX (Barbose et al, 2015) is shown in box and whiskers format (bar represents median, box represents 20th and 80th percentile, whiskers represent minimum and maximum; diamond represents capacity weighted average) for comparison to ATB current CAPEX estimates and future projections. Barbose et al (2015) represents 81% of all U.S. residential and commercial PV capacity installed through 2014 and 62% of capacity installed in 2014. We expect the weighted average market report numbers to be higher than the national cost number we are projecting here because many of the historical installations are in states (e.g., California) where installation costs are high than a national cost number.
- PV pricing and capacities are quoted in W_{DC} (i.e. module rated capacity) as opposed to other generation technologies which are quoted in W_{AC} (for PV this would correspond to the combined rated capacity of all inverters). This is done to correspond with the $1.60/W goal in 2020, and is also the unit that the majority of the PV industry still uses.
- CAPEX estimates should tend toward the low end of observed cost because no regional impacts or spur line costs are included. These effects are represented in the historical market data.
- 2014 & 2015 system price of $3.29/W and $3.10/W are based on modeled pricing for residential systems quoted in Q3 2014 and Q1 2015 respectively, as reported in "Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections 2015 Edition." This is consistent with the $3.59/W and $3.50/W reported in Q1 2015 and Q2 2015 by GTM and SEIA for "Modeled Residential Turnkey System Pricing With Breakdown," but lower than the $4.43/W and $4.22/W reported in Q1 2015 and Q2 2015 for "Capacity-Weighted Average Residential PV System Prices."
- Projections post-2015 are based on a collection of 10 system price projections from 5 separate institutions. The "high" case assumes that CAPEX pricing remains at current levels. The "low" case represents the minimum estimate in the dataset. The "mid" case represents the median estimate in the dataset. For the "low" and "mid" cases the values before 2025 include a price adder, representing the difference between the minimum or median US price estimate and the minimum or median price estimate for the entire dataset. This adder decreases on a straight-line between 2020 and 2025. It is assumed after 2025 US prices will be on par with global averages. To account for the temporal variation in price projections the "mid" and "low" cases make estimates every five years through 2030, and every ten years afterwards, with a straight-line change between estimates. In instances in which analyst projections did not include all years a straight-line change in price was assumed between any two projected values. Additionally, SETO has a program goal of $1.60/W in 2020.
- Note: all prices quoted in Euros converted to USD (1 € = $1.25); all prices quoted in W_{AC} converted to W_{DC} (1 W_{AC}=1.2 W_{DC}).

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Distributed Residential Solar PV Plant Operations and Maintenance Costs

- **Represent annual expenditures required to operate and maintain a solar PV plant over its technical lifetime of 25 years including:**
  - Insurance, legal and administrative fees, and other fixed costs
  - Present value, annualized large component replacement costs over technical life (e.g., inverters)
  - Scheduled and unscheduled maintenance of solar PV plants, transformers, etc. over technical lifetime
- **FOM assumed to be \$20/kW/yr based on Jones-Albertus et al (2015)**
- **Future FOM assumed to decline by 50% by 2020 in Low and by 2025 in Mid.**

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- Represent annual expenditures required to operate and maintain a residential solar PV plant over its technical lifetime of 20 years including:
  - Insurance, legal and administrative fees, and other fixed costs.
  - Present value, annualized large component replacement costs over technical life (e.g., inverters).
  - Scheduled and unscheduled maintenance of solar PV plants, transformers, etc. over technical lifetime.
- FOM assumed to be \$20/kW_{DC}/yr based on Albertus et al (2015). This number is reasonably consistent with the 2013 "Empirical O&M costs" reported in LBNL's "Utility-scale Solar 2013" technical report, which indicates O&M costs ranging from \$15/kW_{AC}/yr to \$25/kW_{AC}/yr for fixed-tilt PV systems (note: this range would be lower if reported in \$$kW_{DC}$/yr). A wide range in reported price exists in the marketplace, in part depending on what maintenance practices exist for a particular system. These cost categories include: asset management (including compliance and reporting for incentive payments), different insurance products, site security, cleaning, vegetation removal, and failure of components. Not all of these practices are performed for each system; additionally, some factors are dependent on the quality of the parts and construction. NREL analysts estimate that O&M costs can range between \$0 - \$40/kW_{DC}/yr.

2013 O&M estimates	Fixed O&M cost (USD per kW DC)			Variable O&M cost (USD per kWh)
	Min.	Median	Max.	
GTM Survey	8 ~ 12	12 ~ 15	15 ~ 25	0
NREL OpenEI Database	7.56	32.47	110	0
EIA		19.97		0
Lazard		13 ~ 20		0
LBNL	16		32	0

- Current O&M costs are based on those outlined in the SunShot Vision Study, including an inverter replacement in year 15. The low case is based on future O&M costs achieved in the SunShot Vision Study in 2020; the high case assumes no O&M cost reduction; the middle case assumes cost reductions between the high and low case in 2020, with costs reducing to the low case by 2030. There is currently great market variation in what individual companies perform for O&M. Typical projects perform some, but not necessarily all, of the following O&M procedures:

  1) Inverter replacement at 15 years
  2) General maintenance (including cleaning and vegetation removal)
  3) Site security
  3) Legal and administrative fees
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References

US Department of Energy, 2012. SunShot Vision Study: February 2012. NREL Report No. BK5200-47927

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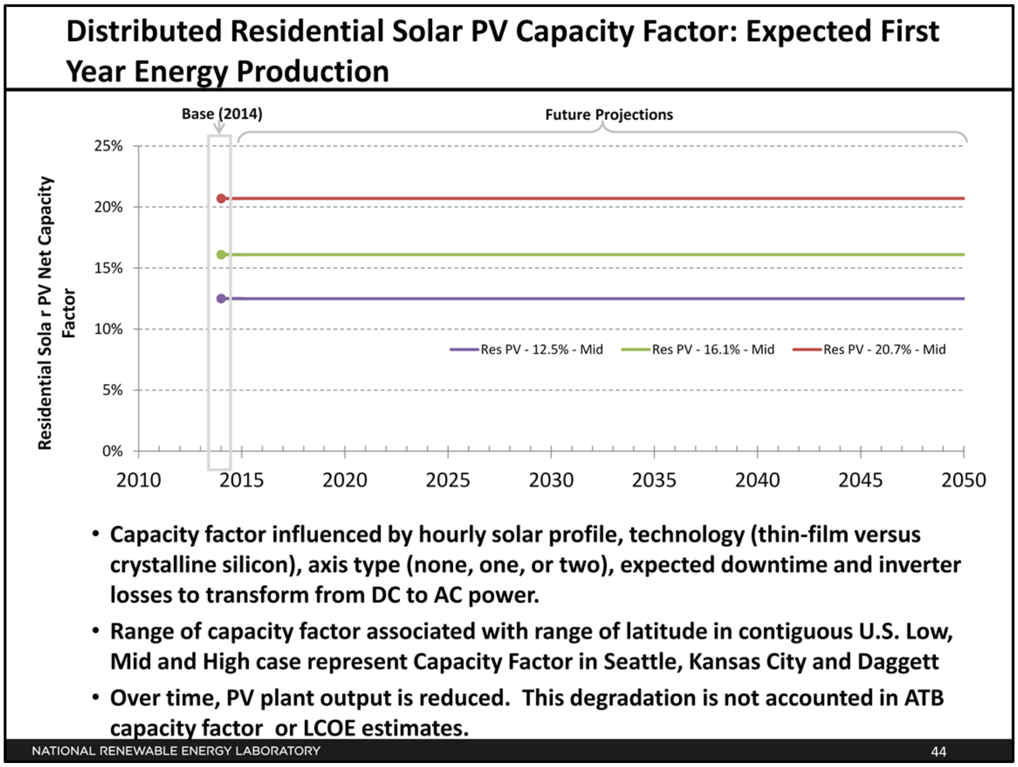

- Capacity factor represents expected annual average energy production divided by annual energy production assuming the plant operates at rated AC capacity for every hour of the year. Intended to represent long-term average over technical lifetime of plant.
- Capacity factor influenced by hourly solar profile, technology (thin-film versus crystalline silicon), axis type (none, one, or two), expected downtime and inverter losses to transform from DC to AC power.
- For illustration in ATB, range of capacity factor associated with range of solar irradiance in contiguous U.S. is shown using Seattle, WA, Kansas City, MO, and Daggett, CA as low, mid, high range ; capacity factors as modeled range from 12 – 21%, though these depend significant on geography and system configuration e.g. fixed-tilt vs single-axis tracking
- Over time, PV plant output is reduced due to degradation in module quality. This degradation is not accounted in ATB capacity factor estimates. In dSolar annual degradation is including in projected system generation when a consumer considers adoption.
- Projections of capacity factor for plants installed in future years are unchanged from current year. Solar-PV plants have very little downtime and inverter efficiency is already optimized, though improvements in panel density are expected.

Standard Scenarios Model Results

- Assumed annual degradation of 0.5% is represented in NPV calculation in dSolar.
- dSolar does not endogenously consider curtailment from surplus RE generation, though this is a feature of the linked ReEDS-dSolar model, where balancing area-level marginal curtailments can be applied to DGPV generation as determined by scenario constraints.

References

National Renewable Energy Laboratory. Regional Energy Deployment System (ReEDS).
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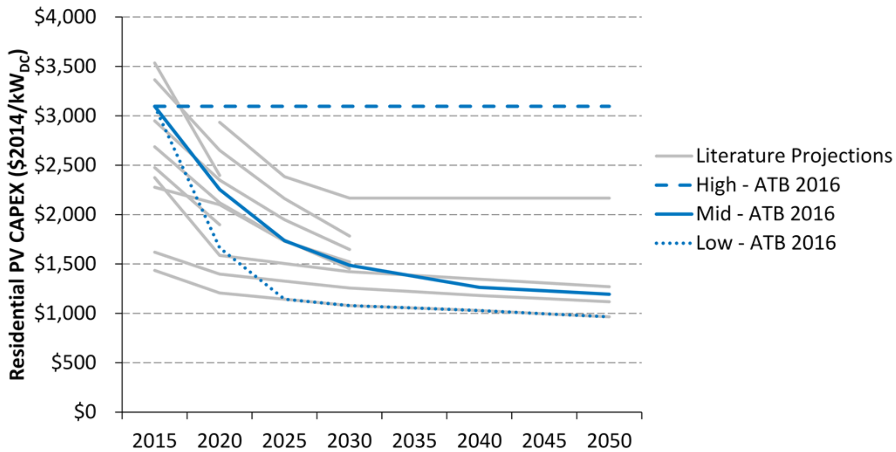
Residential PV Plant Cost and Performance Projections Methodology



- **10 global and US system price projections over time, from 5 separate institutions**
- **Many of the global projections are weighted heavily towards western countries (e.g. Europe, Japan, US) and in the long-term, US should follow global trends – many institutions used one system price for all countries**

Projections post-2015 are based on a collection of 10 system price projections from 5 separate institutions. The “high” case assumes that CAPEX pricing remains at current levels. The “low” case represents the minimum estimate in the dataset. The “mid” case represents the median estimate in the dataset. For the “low” and “mid” cases the values before 2025 include a price adder, representing the difference between the minimum or median US price estimate and the minimum or median price estimate for the entire dataset. This adder decreases on a straight-line between 2015 and 2025. It is assumed after 2025 US prices will be on par with global averages. To account for the temporal variation in price projections the “mid” and “low” cases make estimates every five years through 2030, and every ten years afterwards, with a straight-line change between estimates. In instances in which analyst projections did not include all years a straight-line change in price was assumed between any two projected values. Additionally, SETO has a program goal of $1.60/W in 2020.

Note: all prices quoted in Euros converted to USD (1 € = $1.25); all prices quoted in W_{AC} converted to W_{DC} (1 W_{AC}=1.2 W_{DC}). The maximum value was kept constant after its last year of projection.

Capacity factors are assumed to not increase over time. All PV system efficiency improvements are assumed to result in capital cost reductions rather than capacity factor improvements.

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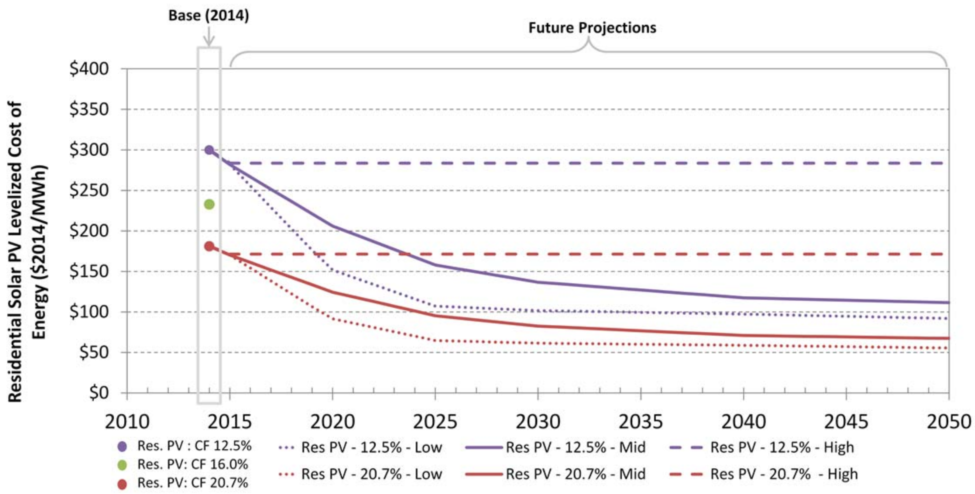
U.S. Energy Information Administration. (2016). *Annual Energy Outlook 2016 Early Release*. May 2016.

Distributed Residential PV Plant Cost and Performance Projections



- **In general, the degree of adoption of a range of technology innovations distinguishes between the low, mid and high cost cases.**
- **The range of LCOE associated with variation in solar resource across the U.S. is reduced from $171-284/MWh in 2014 for High Cost to $55 - 92/MWh for Low Cost reduction scenarios.**

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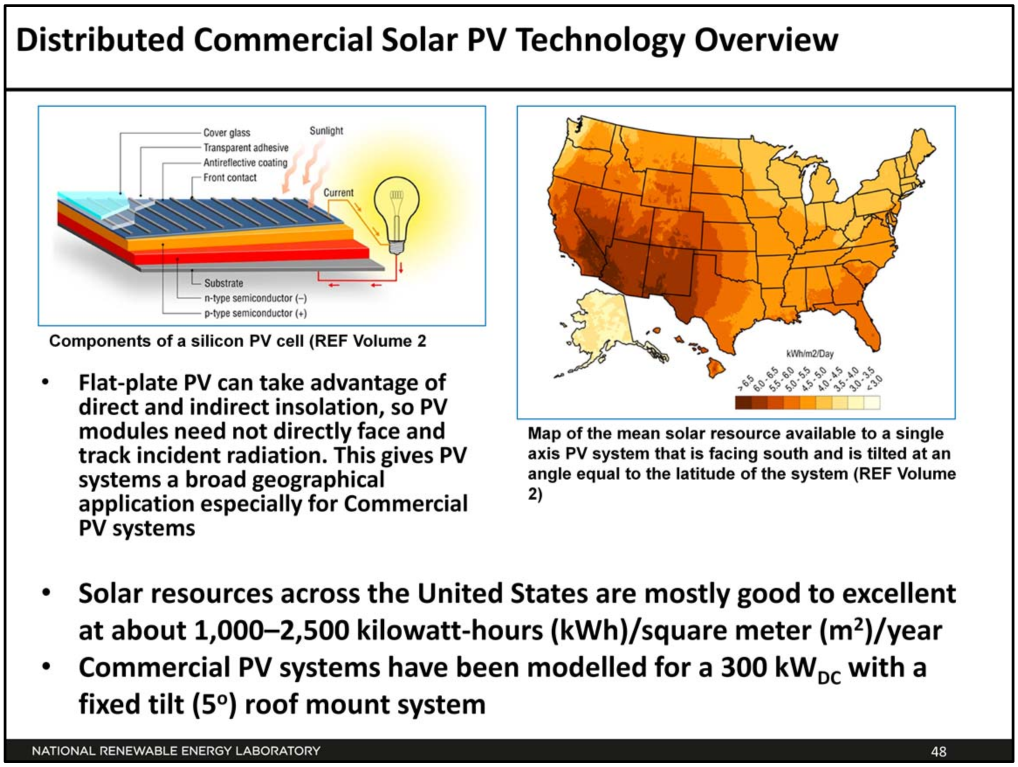
In general, projections represent the following trends to reduce CAPEX and FOM. The degree of adoption distinguishes between Low, Mid, and High PV Cost scenarios.

- Modules
  - Increased module efficiencies and increased production-line throughput to decrease CAPEX (overhead costs on a per-kilowatt will go down if efficiency and throughput improvement are realized).
  - Reduced wafer thickness or the thickness of thin-film semiconductor layers.
  - Development of new semiconductor materials.
  - Thin-film (CdTE and CIGS).
  - Developing larger manufacturing facilities in low-cost regions.
- Balance of System
  - Increased module efficiency, reducing the size of the installation.
  - Development of racking systems that enhance energy production or require less robust engineering.
  - Integration of racking or mounting components in modules.
  - Reduction of supply chain complexity and cost.
    - Create standard packages system design.
    - Improve supply chains for BOS components in modules.
    - Create standard packaged system designs.
    - Improve supply chains for BOS components.
  - Improved power electronics
    - Improve inverter prices and performance, possibly by integrating micro-inverters.
  - Decreased installation costs and margins
    - Reduction of supply chain margins (e.g., profit and overhead charged by suppliers, manufacturer, distributors, and retailers); this will likely occur naturally as the U.S. PV industry grows and matures.
    - Streamlining of installation practices through improved workforce development and training, and developing standardized PV hardware.
    - Expansion of access to a range of innovative financing approaches and business models.
    - Development of best practices for permitting interconnection, and PV installation such as subdivision regulations, new construction guidelines, and design requirements.
- FOM cost reduction represents optimized O&M strategies, reduced component replacement costs and lower frequency of component replacement.

6. Distributed Commercial-Scale Solar PV



- Solar resources across the United States are mostly good to excellent at about 1000 – 2,500 kilowatt-hours (kWh)/square meter (m2)/year. The Southwest is at the top of this range, while only Alaska and part of Washington are at the low end. The range for the 48 contiguous states is about 1,350–2,500 kWh/m2/year. Nationwide, solar resource levels vary by about a factor of two.

- Distributed-scale PV is assumed to be configured as a fixed-axis, roof-mounted system. Compared to Utility-Scale PV, this reduces both the potential capacity factor and amount of land (roof space) that is available for development. A recent study of rooftop PV technical potential estimated that as much as 731 GW (926 TWh/yr) of potential exists for small buildings (< 5,000 m^2 footprint) and 386 GW (506 TWh/yr) for medium (5,000 – 25,000 m^2) and large buildings (>25,000 m^2) (Gagnon et al 2016).

- Distributed-scale PV system cost and performance estimated for all available areas based on typical system cost and hours of sunlight associated with latitude.
    - CAPEX estimated using manufacturing cost models and benchmarked with industry.
    - CF estimated based on low, mid, and high resource areas to represents a range of potential generation.
- Commercial-scale PV plants installed in the U.S. are represented by system size of 300 kW (US DOE, 2012).

References

Volume 2: Renewable Electricity Generation and Storage Technologies. Augustine, C.; Bain, R.; Chapman, J.; Denholm, P.; Drury, E.; Hall, D.G.; Lantz, E.; Margolis, R.; Thresher, R.; Sandor, D.; Bishop, N.A.; Brown, S.R.; Cada, G.F.; Felker, F.; Fernandez, S.J.; Goodrich, A.C.; Hagerman, G.; Heath, G.; O'Neil, S.; Paquette, J.; Tegen, S.; Young, K. (2012). Renewable Electricity Generation and Storage Technologies. Vol 2. of Renewable Electricity Futures Study. NREL/TP-6A20-52409-2. Golden, CO: National Renewable Energy Laboratory.

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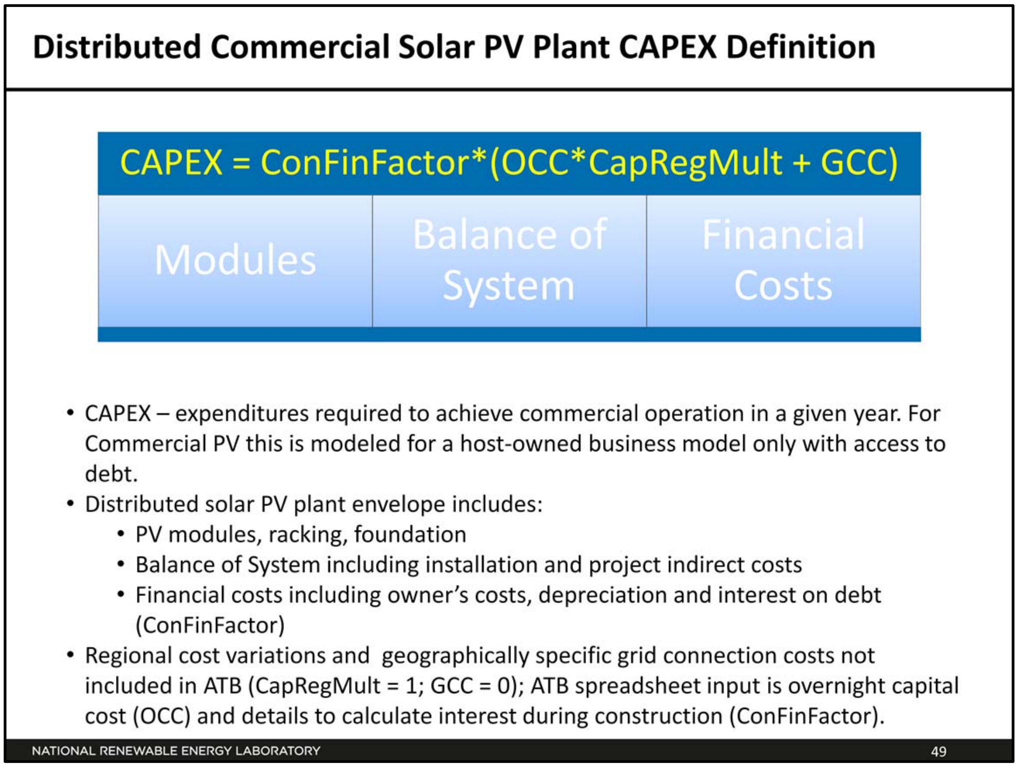
Pieter Gagnon, Robert Margolis, Jennifer Melius, Caleb Phillips, Ryan Elmore. (2016). Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment. NREL Report No. 6A20-65298



- CAPEX in ATB for 2014-15 represent the bottom-up NREL price benchmark, as reported in Woodhouse et al. 2016 and Feldman et al. 2015.; projections post-2015 are based on a collection of 12 system price projections from 6 separate institutions. The "high" case assumes that CAPEX pricing remains at current levels. The "low" case represents the minimum estimate in the dataset. The "mid" case represents the median estimate in the dataset, however the values before 2025 include a price adder, representing the difference between the median US 2015 price estimate and the median 2015 price estimate for the entire dataset. This adder decreases on a straight-line between 2020 and 2025. It is assumed after 2025 US prices will be on par with global averages. To account for the temporal variation in price projections the "mid" and "low" cases make estimates every five years through 2030, and every ten years afterwards, with a straight-line change between estimates. In instances in which analyst projections did not include all years a straight-line change in price was assumed between any two projected values.

- CAPEX represents total expenditure required to achieve operation in a given year. Plant envelope defined to include the following based on NREL Solar-PV Manufacturing Cost Model (Feldman et al. 2015) and (Beamon and Leff, 2013):
  - Modules including
    - module supply, power electronics, racking, foundation, AC & DC materials and installation.
  - Balance of System including
    - Land acquisition, site preparation, installation of underground utilities, access roads, fencing, buildings for operations and maintenance.
    - Electrical infrastructure such as transformers, switchgear and electrical system connecting modules to each other and to control center.
    - Project indirect costs including engineering, distributable labor and materials, construction management start up and commissioning, and contractor overhead costs, fees and profit.
  - Financial Costs
    - Owner's costs such as development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, property taxes during construction.
    - Onsite electrical equipment (e.g., switchyard), a nominal-distance spur line (<1 mi), and necessary upgrades at a transmission substation; distance-based spur line cost (GCC) not included in ATB.
    - Interest during construction estimated based on 1-year duration accumulated 100% at half-year intervals and 8% interest rate.
      - ATB spreadsheet input is Overnight Capital Cost (OCC) and details to calculate interest during construction ConFinFactor.

Standard Scenarios Model Results

- CAPEX in ATB does not represent regional variants (CapRegMult) associated with labor rates, material costs, etc., but dSolar does include 134 regional multipliers (EIA 2013).

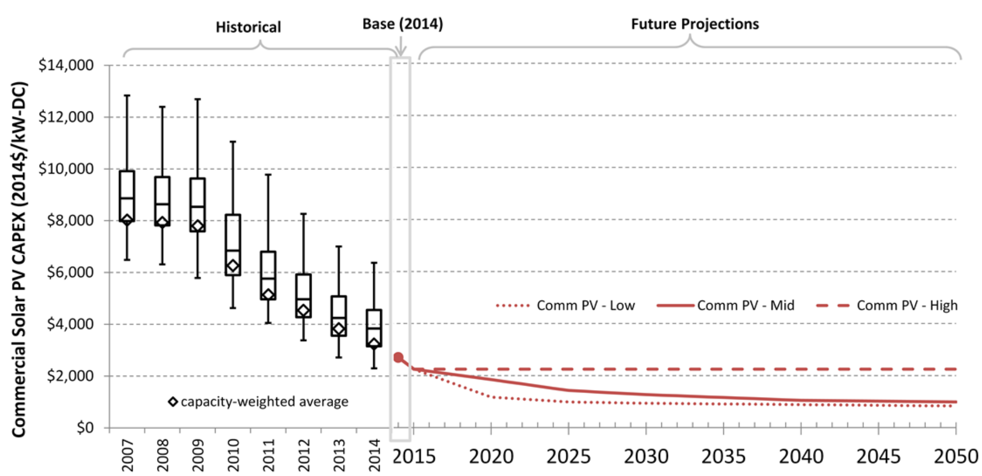
References

Beamon, A.; Leff. M. (2013). EOP III Task 1606, Subtask 3 – Review of Power Plant Cost and Performance Assumptions for NEMS. Prepared by SAIC Energy, Environment & Infrastructure, LLC for the Energy Information Administration, Office of Energy Analysis.
http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf

EIA 2013. *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants.* Washington, DC: U.S. DOE Energy Information Administration. http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf.

Feldman, D.; Barbose, G.; Margolis, M.; Bolinger, M.; Chung, D.; Fu, R.; Seel, J. Davidson, C.; Darghouth, N.; Wiser, R. "Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections 2015 Edition." September 2015. NREL/PR-6A20-64898.

CAPEX (Commercial PV) Historic Trends, Current Estimates, and Future Projections



- CAPEX estimates for 2015 reflect continued rapid decline in pricing supported by analysis of recent system pricing (GTM/SEIA) for projects that became operational in 2015.
- The range in CAPEX estimates reflects the heterogeneous composition of the commercial PV market in the US

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- For illustration in ATB a representative commercial-scale PV plant is shown. Although the variety of PV technologies varies, typical plant costs can be represented with a single estimate.
- Although the technology market share may shift over time with new developments, the typical plant cost is represented with the projections above.
- Actual commercial-scale PV plant CAPEX (Barbose et al, 2015) is shown in box and whiskers format (bar represents median, box represents 20th and 80th percentile, whiskers represent minimum and maximum; diamond represents capacity weighted average) for comparison to ATB current CAPEX estimates and future projections. Barbose et al (2014) represents 81% of all U.S. residential and commercial PV capacity installed through 2014 and 62% of capacity installed in 2014.
- PV pricing and capacities are quoted in W_{DC} (i.e. module rated capacity) as opposed to other generation technologies which are quoted in W_{AC} (for PV this would correspond to the combined rated capacity of all inverters). This is done to correspond with the $1.30/W goal in 2020, and is also the unit that the majority of the PV industry still uses.
- CAPEX estimates should tend toward the low end of observed cost because no regional impacts or spur line costs are included. These effects are represented in the historical market data.
- 2014 & 2015 system prices of $2.64/W and $2.20/W are based on modeled pricing for commercial systems quoted in Q3 2014 and Q1 2015 respectively, as reported in "Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections 2015 Edition." This is consistent with the $2.19/W and $2.13/W reported in Q1 2015 and Q2 2015 by GTM and SEIA for "Modeled Non-Residential Turnkey System Pricing With Breakdown," but lower than the $3.23/W and $3.13/W reported in Q1 2015 and Q2 2015 for "Capacity-Weighted Average Non-Residential PV System Prices."
- Projections post-2015 are based on a collection of 12 system price projections from 6 separate institutions. The "high" case assumes that CAPEX pricing remains at current levels. The "low" case represents the minimum estimate in the dataset. The "mid" case represents the median estimate in the dataset. For the "low" and "mid" cases the values before 2025 include a price adder, representing the difference between the minimum or median US price estimate and the minimum or median price estimate for the entire dataset. This adder decreases on a straight-line between 2020 and 2025. It is assumed after 2025 US prices will be on par with global averages. To account for the temporal variation in price projections the "mid" and "low" cases make estimates every five years through 2030, and every ten years afterwards, with a straight-line change between estimates. In instances in which analyst projections did not include all years a straight-line change in price was assumed between any two projected values. Additionally, SETO has a program goal of $1.3/W in 2020.
- Note: all prices quoted in Euros converted to USD (1 € = $1.25); all prices quoted in W_{AC} converted to W_{DC} ($1\ W_{AC}=1.2\ W_{DC}$).

References

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Sharma, Ash. (2015). *IHS Solar Market Intelligence*. IHS. July 7, 2015.

U.S. Energy Information Administration. (2016). *Annual Energy Outlook 2016 Early Release*. May 2016.

Distributed Commercial Solar PV Plant Operations and Maintenance Costs

- **Represent annual expenditures required to operate and maintain a solar PV plant over its technical lifetime of 25 years including:**
  - Insurance, legal and administrative fees, and other fixed costs
  - Present value, annualized large component replacement costs over technical life (e.g., inverters)
  - Scheduled and unscheduled maintenance of solar PV plants, transformers, etc. over technical lifetime
- **FOM assumed to be \$15/kW/yr based on Jones-Albertus et al (2015)**
- **Future FOM assumed to decline by 50% by 2020 in Low and by 2025 in Mid.**

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- Represent annual expenditures required to operate and maintain a residential solar PV plant over its technical lifetime of 20 years including:
  - Insurance, legal and administrative fees, and other fixed costs.
  - Present value, annualized large component replacement costs over technical life (e.g., inverters).
  - Scheduled and unscheduled maintenance of solar PV plants, transformers, etc. over technical lifetime.
- FOM assumed to be \$15/kW_{DC}/yr based on Albertus et al (2015). This number is reasonably consistent with the 2013 "Empirical O&M costs" reported in LBNL's "Utility-scale Solar 2013" technical report, which indicates O&M costs ranging from \$15/kW_{AC}/yr to \$25/kW_{AC}/yr for fixed-tilt PV systems (note: this range would be lower if reported in \$$kW_{DC}$/yr). A wide range in reported price exists in the marketplace, in part depending on what maintenance practices exist for a particular system. These cost categories include: asset management (including compliance and reporting for incentive payments), different insurance products, site security, cleaning, vegetation removal, and failure of components. Not all of these practices are performed for each system; additionally, some factors are dependent on the quality of the parts and construction. NREL analysts estimate that O&M costs can range between \$0 - \$40/kW_{DC}/yr.

2013 O&M estimates	Fixed O&M cost (USD per kW DC)			Variable O&M cost (USD per kWh)
	Min.	Median	Max.	
GTM Survey	8 ~ 12	12 ~ 15	15 ~ 25	0
NREL OpenEI Database	7.56	32.47	110	0
EIA		19.97		0
Lazard		13 ~ 20		0
LBNL	16		32	0

- Current O&M costs are based on those outlined in the SunShot Vision Study, including an inverter replacement in year 15. The low case is based on future O&M costs achieved in the SunShot Vision Study in 2020; the high case assumes no O&M cost reduction; the middle case assumes cost reductions between the high and low case in 2020, with costs reducing to the low case by 2030. There is currently great market variation in what individual companies perform for O&M. Typical projects perform some, but not necessarily all, of the following O&M procedures:
  1) Inverter replacement at 15 years
  2) General maintenance (including cleaning and vegetation removal)
  3) Site security
  3) Legal and administrative fees
  4) Insurance
  5) Property taxes

References

US Department of Energy, 2012. SunShot Vision Study: February 2012. NREL Report No. BK5200-47927

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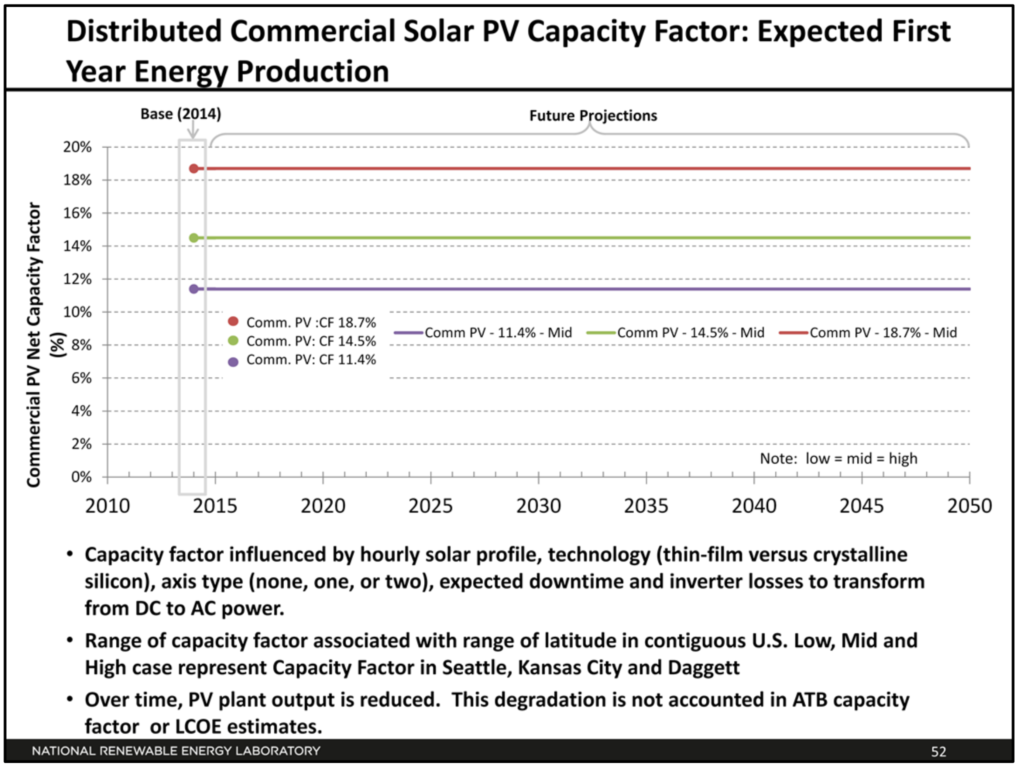

- Capacity factor represents expected annual average energy production divided by annual energy production assuming the plant operates at rated AC capacity for every hour of the year. Intended to represent long-term average over technical lifetime of plant.
- Capacity factor influenced by hourly solar profile, technology (thin-film versus crystalline silicon), axis type (none, one, or two), expected downtime and inverter losses to transform from DC to AC power.
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- Projections of capacity factor for plants installed in future years are unchanged from current year. Solar-PV plants have very little downtime and inverter efficiency is already optimized, though improvements in panel density are expected.

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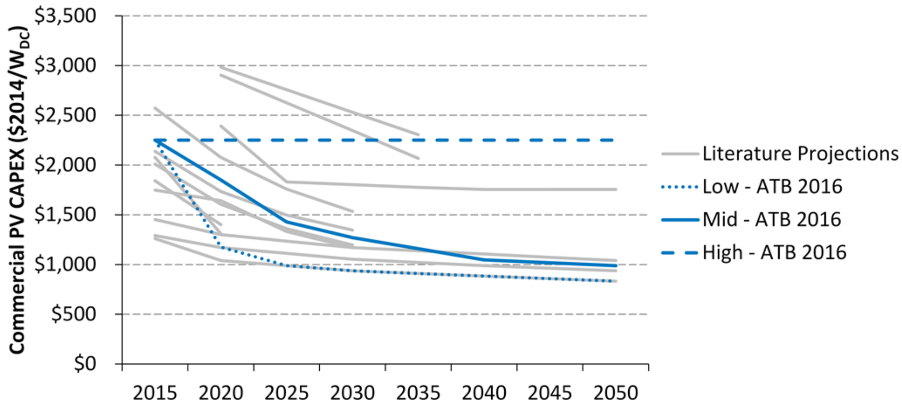
Commercial-scale PV Plant Cost and Performance Projections Methodology



- **12 global and US system price projections over time, from 6 separate institutions**
- **Many of the global projections are weighted heavily towards western countries (e.g. Europe, Japan, US) and in the long-term, US should follow global trends – many institutions used one system price for all countries**

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Projections of future utility-scale PV plant CAPEX are based on the a collection of 12 system price projections from 5 separate institutions with low, mid, and high representing the minimum, median, and maximum estimates in this dataset.

Note: all prices quoted in Euros converted to USD (1 € = $1.25); all prices quoted in W_{AC} converted to W_{DC} (1 W_{AC}=1.2 W_{DC}).

Capacity factors are assumed to not increase over time. All PV system efficiency improvements are assumed to result in capital cost reductions rather than capacity factor improvements.

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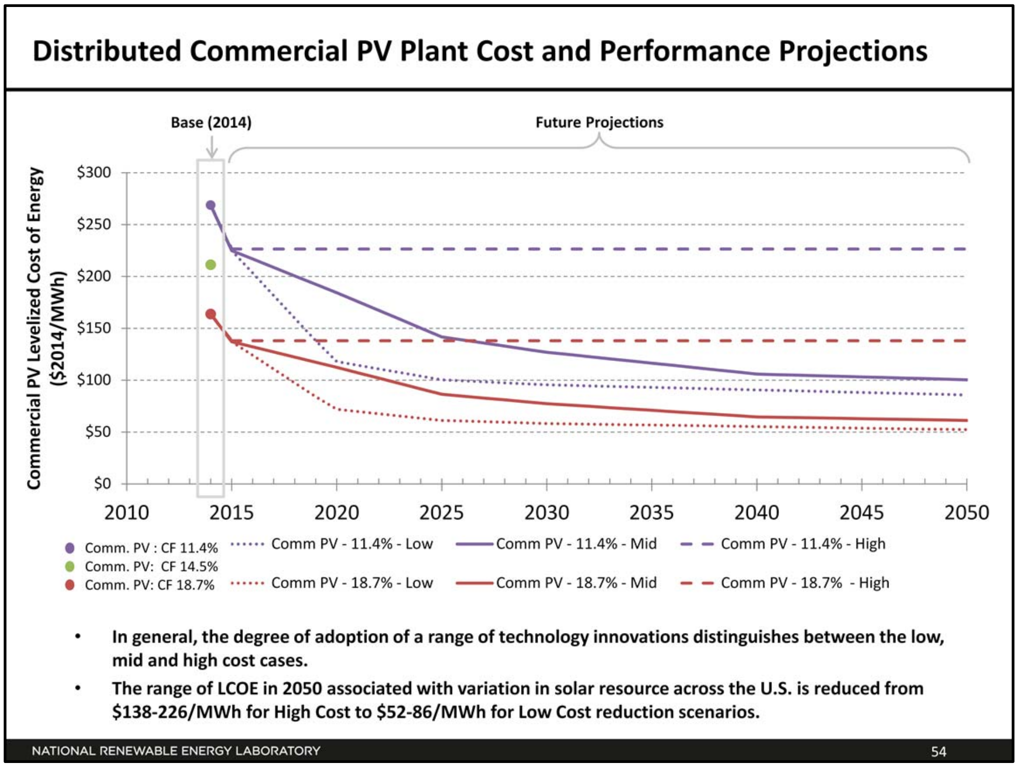

- Note: Since the draft version of this product was posted, current and projected overnight capital cost values for the ATB mid-case Solar PV projection have been modified downward to reflect the significant change in solar market prices that has occurred over the last year. The 2014 overnight capital cost for utility-scale PV has been lowered to $1.90/W, a 20% reduction from the earlier draft, to be in line with the most recent quarterly solar market report available. In turn, these lower costs in 2014 have increased our confidence that the SunShot target of $1.00/W will be achieved earlier. As such, the mid-case projection reduces the 2014 cost to $1.50/W by 2020 (same as earlier draft), and assumes the SunShot target is reached by 2030 instead of 2040 previously (reducing projected costs beyond 2020 by 10-20% from the earlier draft).

- In general, projections represent the following trends to reduce CAPEX and FOM. The degree of adoption distinguishes between Low, Mid, and High PV Cost scenarios.
- Modules
    - Increased module efficiencies and increased production-line throughput to decrease CAPEX (overhead costs on a per-kilowatt will go down if efficiency and throughput improvement are realized).
    - Reduced wafer thickness or the thickness of thin-film semiconductor layers.
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        - Streamlining of installation practices through improved workforce development and training, and developing standardized PV hardware.
        - Expansion of access to a range of innovative financing approaches and business models.
        - Development of best practices for permitting interconnection, and PV installation such as subdivision regulations, new construction guidelines, and design requirements.
- FOM cost reduction represents optimized O&M strategies, reduced component replacement costs and lower frequency of component replacement.

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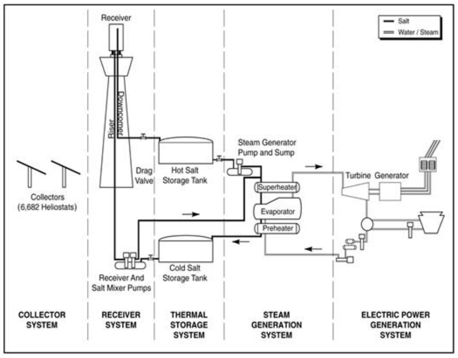
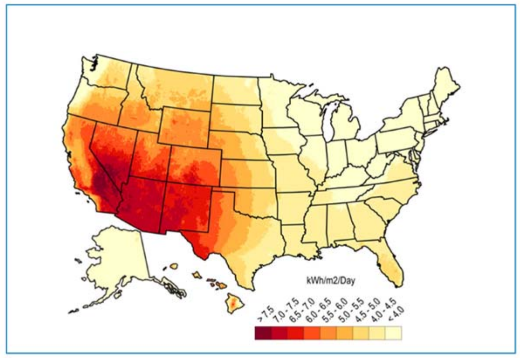
7. Concentrating Solar Power (CSP) Plants

Concentrating Solar Power (CSP) Plant Technology Overview



Base representation of 100MWe CSP Power Tower system with 2 tank Thermal Energy Storage (TES) [Turchi et al, 2015]



Map of mean U.S. solar resource available to CSP systems

- **Common CSP technologies (i.e. Parabolic Trough and Tower Tower) utilize Direct Normal Irradiance (DNI), suited for desert like areas**
- **Raw potential of Southwestern states exceeds 11,000 GW**
- **Solar resources across the Southwest United States are mostly Fair to Excellent at about 2,000 – 2,800 kilowatt-hours (kWh)/m^2/year**

- Solar resource prevalent throughout the U.S., but the southwest states are particularly suited to CSP plants. The resource potential for seven western states (AZ, CA, CO, NV, NM, UT, and TX) exceeds 11,000 GW assuming an annual average resource > 6.0 kWh/m2/day, and after accounting for exclusions such as land slope (>1%); urban areas; water features; and parks, preserves, and wilderness areas **[Mehos, Kabel, and Smithers, 2009].**
- The Solar Programmatic Environmental Impact Statement identified 17 solar energy zones (SEZ) in six western states. The 17 SEZs are priority development areas for utility-scale solar energy facilities. These zones total 285,000 acres and are estimated to accommodate up to 24 GW of solar potential. The program also allows development, subject to a more rigorous review, on an additional 19 million acres of public land. Development is prohibited on approx. 79 million acres. [solareis.anl.gov]
- 16 of 19 currently operational CSP plants in the US using parabolic trough technology. Three power tower facilities: Ivanpah (392 MW), Crescent Dunes (110 MW), and Sierra SunTower (5 MW) are operational. Two small linear Fresnel plants are in operation. [www.nrel.gov/csp/solarpaces]
- For the ATB, 3 representative sites have been chosen based on resource class:
  - Fair Resource e.g. Abilene Regional Airport, TX (5.59 kWh/m^2/day based on the site TMY3 file)
  - Good Resource e.g. Las Vegas, NV (7.1 kWh/m^2/day based on the site TMY3 file)
  - Excellent Resource e.g. Daggett, CA (7.46 kWh/m^2/day based on the site TMY3 file)
- CAPEX determined using manufacturing cost models and benchmarked with industry data. Reflects dry-cooling technologies to reduce water consumption.
- CF varies with inclusion of thermal energy storage. The listed projects assume Power Towers with 10hrs of thermal energy storage.
- Representative CSP plant size is net 100 MWe.
- Solar resource for the Southwest U.S. found from “CSP Today Markets Report - USA”

References
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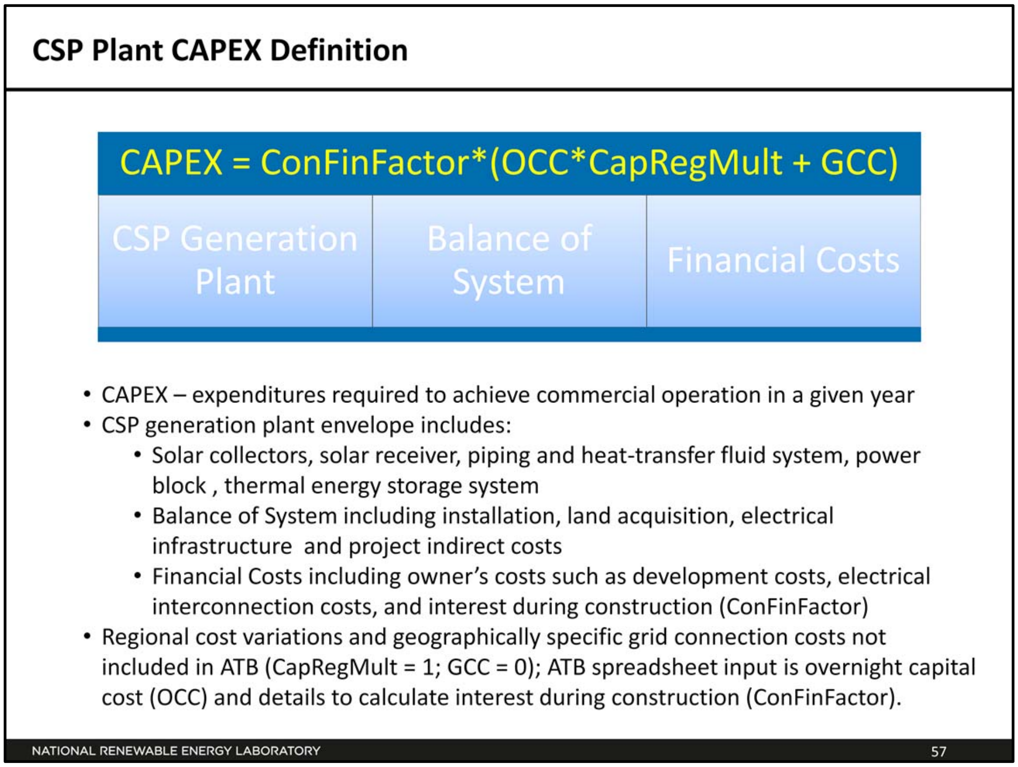
Bureau of Land Management and the U.S. Department of Energy. (2012). Final Programmatic Environmental Impact Statement (PEIS) for Solar Energy Development in Six Southwestern States. http://solareis.anl.gov/documents/fpeis/index.cfm.

www.nrel.gov/csp/solarpaces



- CAPEX in ATB represents solar CSP plant cost based on modeled system prices from industry survey plus indexed costs since last detailed cost study for the fourth quarter of the previous year.

- CAPEX in ATB may not explicitly represent regional variants associated with labor rates, material costs, etc. or geographically determined spur lines costs.
- CAPEX represents total expenditure required to achieve commercial operation in a given year. Plant envelope defined to include the following based on Beamon and Leff (2013), NREL/TP-550-47605, NREL/TP-5500-57625
  - CSP Generation Plant including
    - installed solar collectors, solar receiver, piping and heat-transfer fluid system, power block (heat exchangers, power turbine, generator, cooling system), thermal energy storage system and installation
  - Balance of System including
    - land acquisition, site preparation, installation of underground utilities, access roads, fencing, buildings for operations and maintenance
    - electrical infrastructure such as transformers, switchgear and electrical system connecting modules to each other and to control center. The generator voltage is 13.8 kV, the step-up transformer will be 13.8/230kV, the transmission tie line will be 230 kV
    - project indirect costs including engineering, distributable labor and materials, construction management start up and commissioning, and contractor overhead costs, fees and profit.
  - Financial Costs
    - owner's costs such as development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, property taxes during construction
    - onsite electrical equipment (e.g., switchyard), a nominal-distance spur line (<1 mi), and necessary upgrades at a transmission substation; distance-based spur line cost (GCC) not included in ATB.
    - interest during construction estimated based on 3-year duration accumulated 10%/10%/80% at half-year intervals and 8% interest rate

      ATB spreadsheet input is Overnight Capital Cost (OCC) and details to calculate interest during construction (ConFinFactor).

Standard Scenarios Model Results

- CAPEX in ATB does not represent regional variants (CapRegMult) associated with labor rates, material costs, etc., but ReEDS does include 134 regional multipliers (Beamon and Leff, 2013)

- CAPEX in ATB does not include geographically determined spur line (GCC) from plant to transmission grid, but ReEDS calculates a unique value for each potential CSP plant

References

Beamon, A.; Leff. M. (2013). EOP III Task 1606, Subtask 3 – Review of Power Plant Cost and Performance Assumptions for NEMS. Prepared by SAIC Energy, Environment & Infrastructure, LLC for the Energy Information Administration, Office of Energy Analysis. http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf

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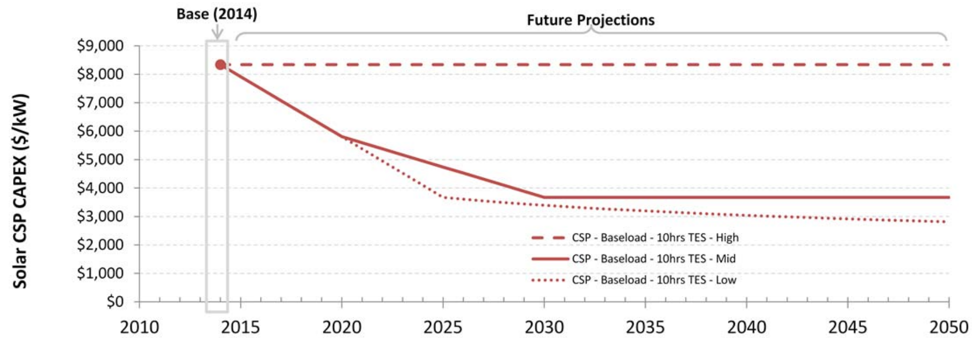
Kurup, P and Turchi, C. (2015), Parabolic Trough Collector Cost Update for the System Advisor Model (SAM). NREL Report No. TP-6A20-65228

Turchi, C. S.; Heath, G. A. (2013). Molten Salt Power Tower Cost Model for the System Advisor Model (SAM). 53 pp.; NREL Report No. TP-5500-57625.

CAPEX Historic Trends, Current Estimates, and Future Projections



- **CAPEX estimate (2014) is ~$8300/kW, for representative Power Tower with 10hrs of storage (and solar multiple of 2.4)**
  - **High**: Molten-salt (sodium nitrate/potassium nitrate, aka, solar salt) Power Tower with direct, 2-tank TES combined with a steam-Rankine power cycle running at 574°C and 41.2% gross efficiency in 2015. Costs stay as per the Base year throughout time
  - **Mid**: Reduced heliostat cost due to greater deployment volume and R&D. New fluids increase operating temperatures to 600°C by 2020 and 700°C by 2030. Advanced power cycles deployed to take advantage of higher operating temperatures.
  - **Low:** Reduced heliostat cost due to greater deployment volume and R&D. New fluids increase operating temperatures to 600°C by 2020 and 700°C by 2025. Advanced power cycles deployed to take advantage of higher operating temperatures. From 2025 potential Learning Rates for the power block and solar field applied.
- **CAPEX assumed to be the same at different resources, as such only one set of High, Mid and Low projections are shown**

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The CAPEX is unchanged for resource class because the same plant is assumed to be built in each location. The capacity factor will change with resource.

- Parabolic trough technology was used to describe CSP systems prior to 2025 in last year's ATB release. For this year, it is now assumed that molten-salt power towers are the representative technology. Either technology can incorporate TES, although power towers do that more efficiently. In both technologies, TES is accomplished by storing hot molten salt in a "2-tank" system – a hot-salt tank and a cold-salt tank. Stored, hot salt can be dispatched to the power block as needed, regardless of solar conditions.
- Thermal energy storage increases plant CAPEX, but also increases CF and annual efficiency. Thermal storage lowers LCOE for power towers.
- Various US and international studies have been made, and will be continued in the future to give Historical CAPEX estimates
- For the Low Case, where Learning Rates have been applied, a Learning Rate of 9.9% for the solar field and a Learning Rate of 12% for the Turbine have been used.
- The first large Molten-salt power tower plant (i.e. Crescent Dunes, 110MWe with 10hrs of storage) started construction in 2011, with a reported Overnight Capital Cost of $8.96/W$_{AC}$

References:

Kurup, P and Turchi, C. (2015), Parabolic Trough Collector Cost Update for the System Advisor Model (SAM). NREL Report No. TP-6A20-65228

Turchi, C. S.; Heath, G. A. (2013). Molten Salt Power Tower Cost Model for the System Advisor Model (SAM). 53 pp.; NREL Report No. TP-5500-57625.

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Rubin, E.S. et al., "A Review of Learning Rates for Electricity Supply Technologies," Energy Policy, 86 (2015)

International Energy Agency, Technology Roadmap, Solar Thermal Electricity (2014) - https://www.iea.org/publications/freepublications/publication/TechnologyRoadmapSolarThermalElectricity_2014edition.pdf

Sandia National Laboratories, "Crescent Dunes Solar Energy Project", Sandia, Jul. 2014, http://www.energystorageexchange.org/projects/348#

Mehos, M and Ho, C, (2016 - in Red Team Review), "On the Path to SunShot – CSP Technology Development Roadmap", NREL, link to be provided when released

CSP Plant Operations and Maintenance (O&M) Costs

- **Represent annual expenditures required to operate and maintain a solar CSP plant over its technical lifetime of 30 years including:**
  - Operating and administrative labor, insurance, legal and administrative fees, and other fixed costs
  - Utilities (water, power, natural gas) and mirror washing
  - Scheduled and unscheduled maintenance including replacement parts for solar field and power block components over technical lifetime
- **Fixed O&M (FOM) assumed to be $66/kW/yr; Variable O&M (VOM) is approximately $4/MWh. [Kurup & Turchi, 2015]**
- **Future FOM assumed to decline by 15% ($56/kW/yr) by 2020 in Low and Mid cost cases. Further drops to the SunShot target of $40/kW/yr by 2030 (Mid) and 2025 (Low). [SunShot Vision Study, 2012]**

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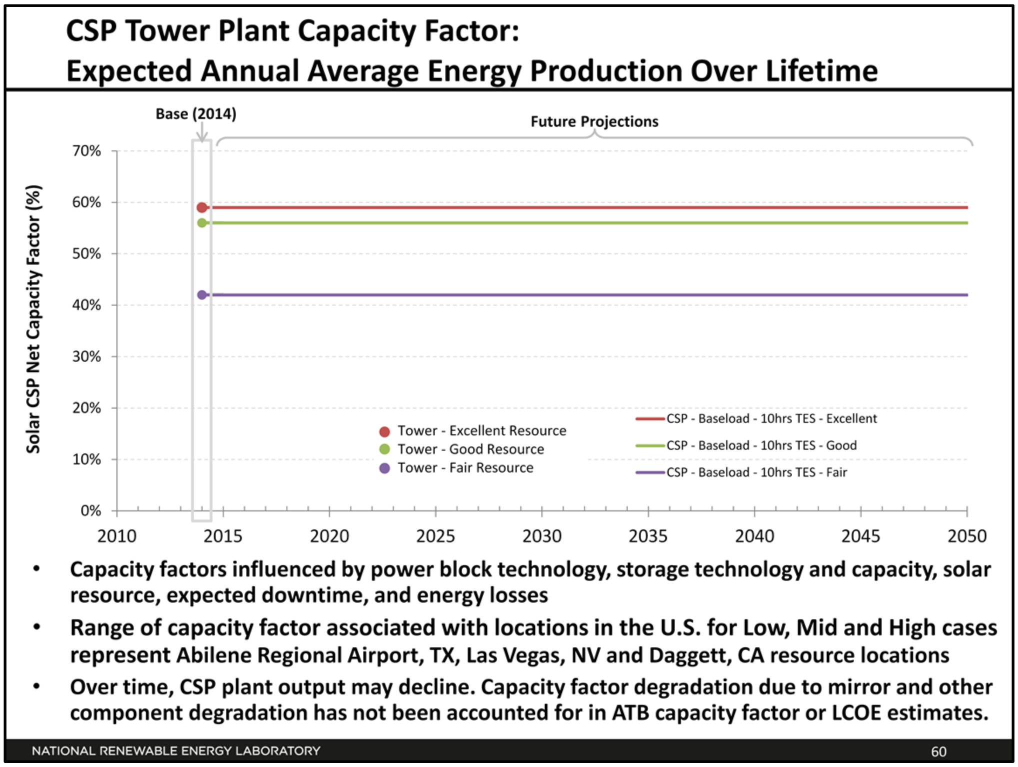
- Represent annual expenditures required to operate and maintain a solar CSP plant over its technical lifetime of 30 years including:
  - Operating and administrative labor, insurance, legal and administrative fees, and other fixed costs
  - Utilities (water, power, natural gas) and mirror washing
  - Scheduled and unscheduled maintenance including replacement parts for solar field and power block components over technical lifetime

References

Turchi, C. (2010). Parabolic Trough Reference Plant for Cost Modeling with the Solar Advisor Model (SAM). 112 pp.; NREL Report No. TP-5500-47605.

Kurup, P and Turchi, C. (2015), Parabolic Trough Collector Cost Update for the System Advisor Model (SAM). NREL Report No. TP-6A20-65228

Turchi, C. S.; Heath, G. A. (2013). Molten Salt Power Tower Cost Model for the System Advisor Model (SAM). 53 pp.; NREL Report No. TP-5500-57625.



- Capacity factor is defined as annual average energy production divided by annual energy production assuming the plant operates at rated capacity for every hour of the year. Intended to represent long-term average over technical lifetime of plant and does not represent inter-annual variation in energy production.

- Capacity factor influenced by the technology, storage technology and capacity, expected downtime and the solar resource. The CSP technologies are assumed to be power towers, but with different power cycles and operating conditions as time passes:

    - (2015) a molten-salt (sodium nitrate/potassium nitrate, aka, solar salt) power tower with direct, 2-tank TES combined with a steam-Rankine power cycle running at 574 C and 41.2% gross efficiency.

    - (2020) a molten-salt (sodium nitrate) power tower with direct, 2-tank TES combined with a supercritical CO_2 power cycle running at 600 C and 44.7% gross efficiency.

    - (2025 or 2030) SunShot targets are met – modeled as molten-salt power tower with direct, 2-tank TES combined with a power cycle running at 700 C and 55% gross efficiency

- For illustration in ATB, range of capacity factor associated with locations in U.S. as represented in ReEDS for three classes of insolation.
  Fair Resource e.g. Abilene Regional Airport, TX (5.59 kWh/m^2/day based on the site TMY3 file) = 42% CF
  Good Resource e.g. Las Vegas, NV (7.1 kWh/m^2/day based on the site TMY3 file) = 56% CF
  Excellent Resource e.g. Daggett, CA (7.46 kWh/m^2/day based on the site TMY3 file) = 59% CF
    - The ATB capacity factors are slightly down-rated from SAM 2015 projections

- These CF estimates represent typical operation; the dispatch characteristics of these systems are valuable to the electric system to manage changes in net electricity demand. Actual capacity factors will be influenced by the degree to which system operators call on solar-CSP plants to manage grid services.

Standard Scenarios Model Results

- CSP plants with thermal storage can be dispatched by grid operators to accommodate diurnal and seasonal load variations and output from variable generation sources (wind and solar-PV). Because of this, their annual energy production and the value of that generation is determined by the electric system needs and capacity and ancillary services markets.

References

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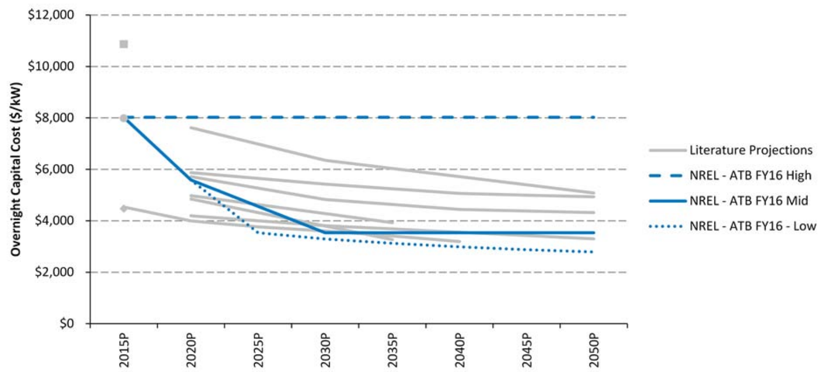
CSP Plant Cost and Performance Projections Methodology



- Three different projections developed for scenario modeling as bounding levels
  - **High**: assumes current molten-salt Power Towers stay the same over time
  - **Mid**: assumes new heat transfer fluids deployed in Power Tower systems to increase operating temperature and efficiency. Increases in heliostat deployment. Assumes SunShot CAPEX and O&M targets hit by 2030.
  - **Low:** assumes SunShot CAPEX and O&M targets are met in 2025, including new, high-efficiency power cycles and low-cost heliostats .
- In comparing with other projections, note that there are major differences in technology assumptions, radiation conditions, field sizes, storage configurations, etc.

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- Projections based on SunShot Vision study and vetted with solar industry participants.
- Attempts have been made to clarify the specifics (e.g. number of hours of storage, solar multiple) of the other published CSP projections. As yet, this has not been possible
- Three different projections developed for scenario modeling as bounding levels
  - (High) – Molten-salt (sodium nitrate/potassium nitrate, aka, solar salt) power tower with direct, 2-tank TES combined with a steam-Rankine power cycle running at 574 C and 41.2% gross efficiency in 2015. Costs stay same over time
  - (Mid) - A molten-salt (sodium nitrate) power tower with direct, 2-tank TES combined with a supercritical CO2 power cycle running at 600 C and 44.7% gross efficiency in 2020. SunShot targets are met in 2030 – modeled as molten-salt power tower with direct, 2-tank TES combined with a power cycle running at 700 C and 55% gross efficiency.
  - (Low) SunShot targets are met in 2025 – modeled as molten-salt power tower with direct, 2-tank TES combined with a power cycle running at 700 C and 55% gross efficiency. For the Low Case, where Learning Rates have been applied, a Learning Rate of 9.9% for the solar field and a Learning Rate of 12% for the Turbine have been used.

References

US Department of Energy, 2012. SunShot Vision Study: February 2012. NREL Report No. BK5200-47927

Sandia National Laboratory. (2011). Power Tower Technology Roadmap. SAND2011-2419.

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Mills, Luke. (2015). H2 2015 *Global Levelized Cost Of Electricity Update*. Bloomberg New Energy Finance. October 1, 2015.

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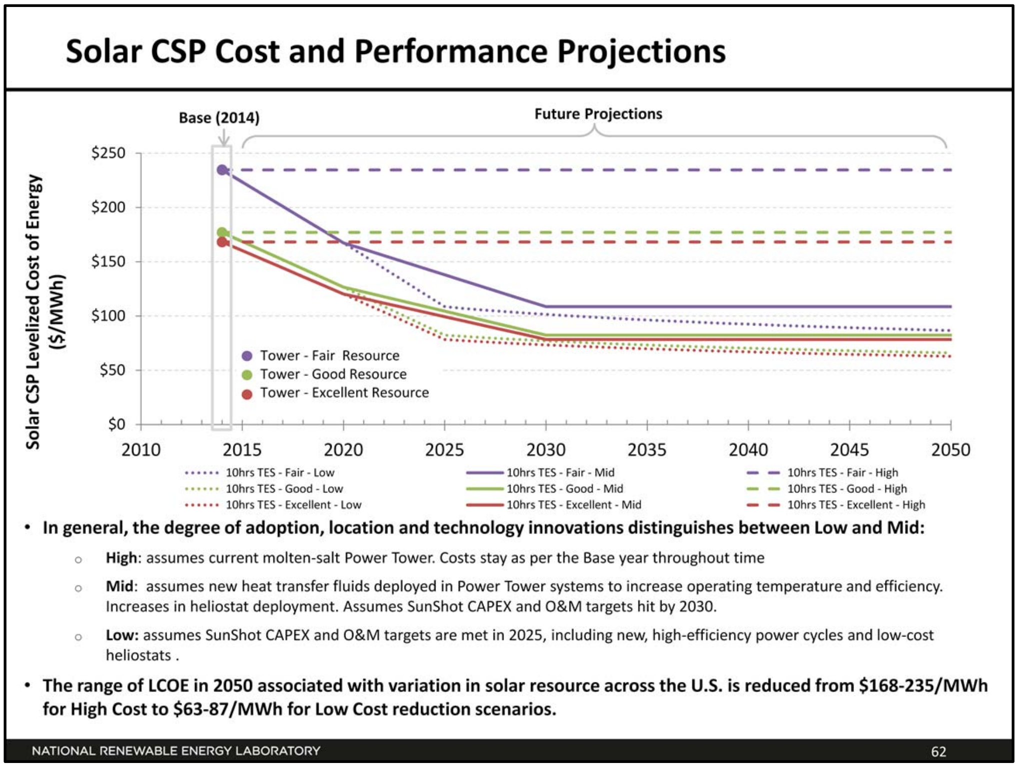


In general, projections represent the following trends, and the degree of adoption distinguishes between Low, Mid and High CSP Cost scenarios as described on previous slide.

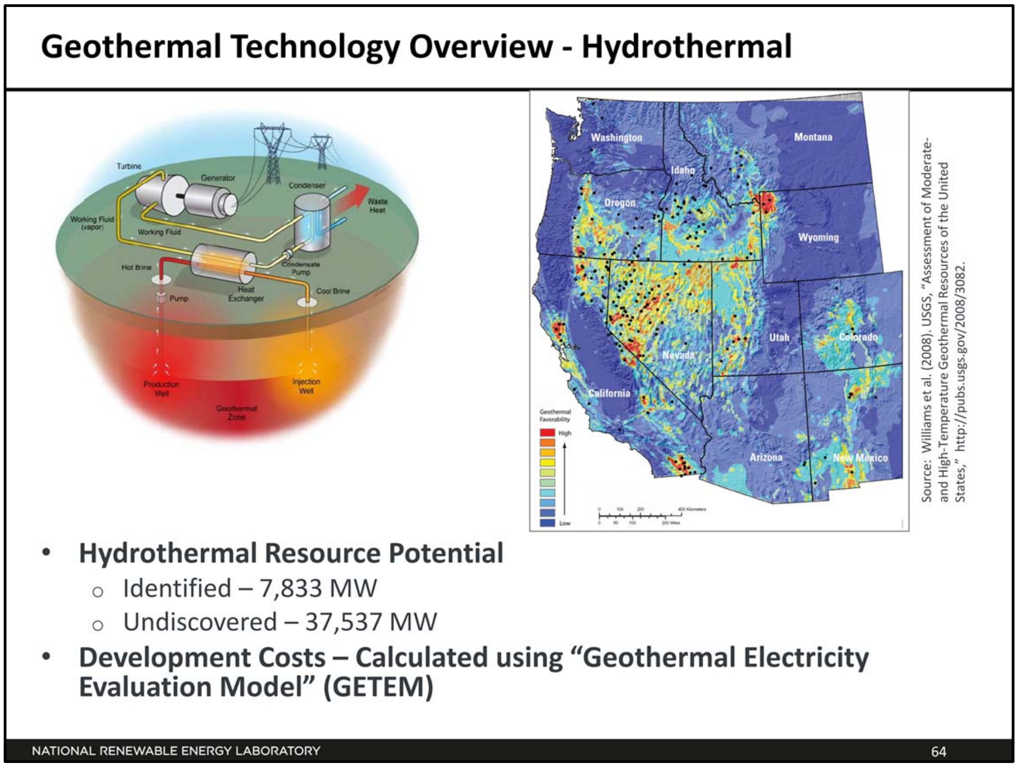
LCOE range shown based on locations with Fair, Good and Excellent resources. The CAPEX is the same at each resource as the same plant is used

Resources taken at i.e. Fair - Abilene Regional Airport, TX; Good - Las Vegas, NV; and Excellent - Daggett, CA.

Power Tower improvements:
- Better and longer-lasting selective surface coatings improve receiver efficiency and reduce O&M costs
- New salts allow for higher operating temperatures and lower cost TES
- Development of the supercritical CO2 power cycle improves cycle efficiency, reduces powerblock cost, and reduces O&M costs
- Lower cost heliostats developed due to more efficient designs, and automated and high-volume manufacturing

General and “soft” costs improvements:
- Modular plant designs decrease installation costs and margins
- Expansion of world market leads to greater and more efficient supply chains; reduction of supply chain margins (e.g., profit and overhead charged by suppliers, manufacturer, distributors, and retailers)
- Expansion of access to a range of innovative financing approaches and business models
- Development of best practices for permitting interconnection, and installation such as subdivision regulations, new construction guidelines, and design requirements

8. Geothermal Power Plants: Flash and Binary Organic Rankine Cycle



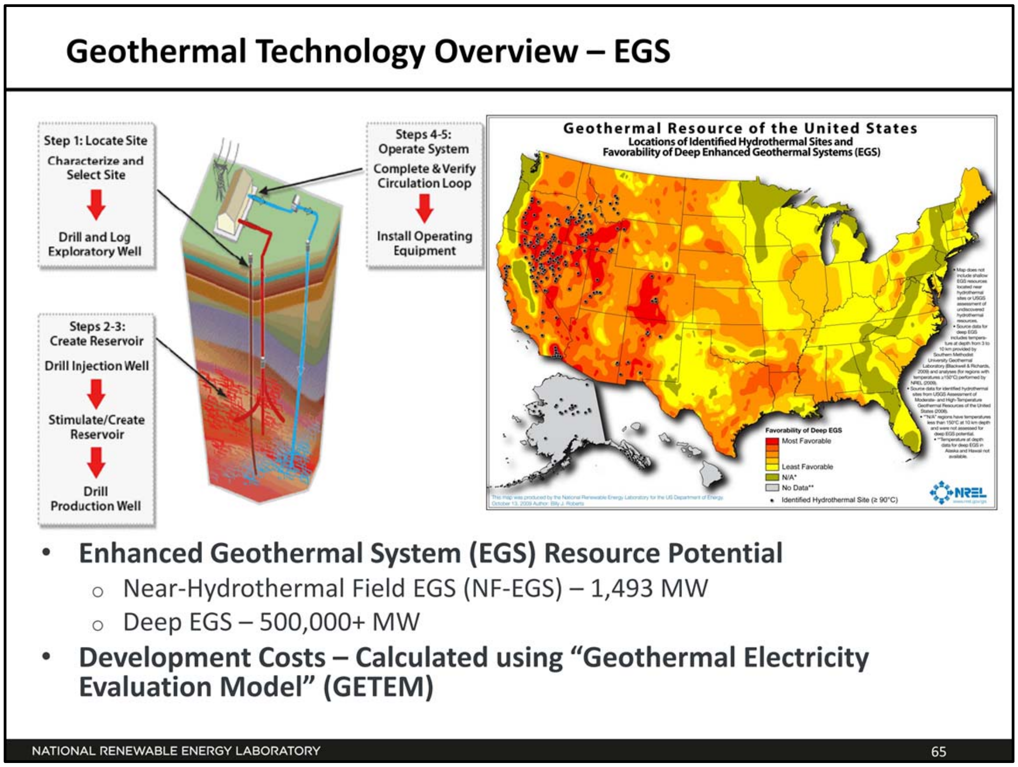
- Hydrothermal geothermal resource concentrated in Western US – total potential is 45,370 MW
- Identified Hydrothermal from USGS 2008 Updated Geothermal Resource Assessment
    - Resource potential estimate at each site identified by USGS based on available reservoir thermal energy information from studies conducted at the site.
    - Installed capacity of about 3 GW in 2014 excluded from resource potential
    - Resource potential estimates increased 20-30% to reflect impact of in-field EGS technologies to increase productivity of dry wells and increase recovery of heat in place from hydrothermal reservoirs.
- Undiscovered hydrothermal values from USGS 2008 Updated Geothermal Resource Assessment
    - Resource potential estimated based on a series of GIS statistical models for the spatial correlation of geological factors that facilitate the formation of geothermal systems.
    - Resource potential estimates increased 20-30% to reflect impact of in-field EGS technologies to increase productivity of dry wells and increase recovery of heat in place from hydrothermal reservoirs.

- Hydrothermal generation plant cost and performance estimated for each potential site using GETEM, a bottom-up cost analysis tool that accounts for each phase of development of a geothermal plant. Model results based on resource attributes (estimated reservoir temperature, depth, and potential) at each site.
    - Site attribute values from USGS (2008) for identified resource potential, and capacity weighted averages of site attribute values from nearby identified resources for undiscovered resource potential.
    - GETEM used to estimate overnight capital cost, and parasitic plant losses that affect net energy production
- Typical geothermal plant size for hydrothermal resource sites are represented from 30 MW to 40 MW depending on technology type, binary or flash. https://www4.eere.energy.gov/geothermal/sites/default/files/documents/mines_getem_peer2013.pdf, Slide 9.

References

U .S. Department of Energy. (2012). Geothermal Energy Technology Evaluation Model (GETEM). http://energy.gov/eere/geothermal/geothermal-electricity-technology-evaluation-model.

Williams, C.; Reed, M.; Mariner, R.; DeAngelo, J.; Galanis, S. (2008). Assessment of moderate- and high-temperature geothermal resources of the United States: U.S. Geological Survey Fact Sheet 2008-3082.



- Near Field-EGS Resource Potential based on data from USGS for EGS potential on the periphery of select, studied, identified hydrothermal sites estimated at 1,493 MW.
- Deep EGS resource potential (Augustine 2011), based on SMU Geothermal Laboratory temp-at-depth maps and methodology from MIT Future of Geothermal Energy Report
    - EGS resource is thousands of GW (16,000 GW) and many locations are likely not commercially feasible.
    - Approaches to restrict resource potential to about 500 GW based on USGS analysis may be implemented in the future.
- EGS generation plant cost and performance estimated for each potential site using GETEM, a bottom-up cost analysis tool that accounts for each phase of development of a geothermal plant. Model results based on resource attributes (estimated reservoir temperature, depth, and potential) at each site.
    - Site attribute values from USGS (2008) for identified resource potential, and capacity weighted averages of site attribute values from nearby identified resources for undiscovered resource potential.
    - GETEM used to estimate overnight capital cost, and parasitic plant losses that affect net energy production
- Typical geothermal plant size for enhanced geothermal system plants are represented by a range from 20 MW to 25 MW for binary or flash technologies. https://www4.eere.energy.gov/geothermal/sites/default/files/documents/mines_getem_peer2013.pdf, Slide 9.

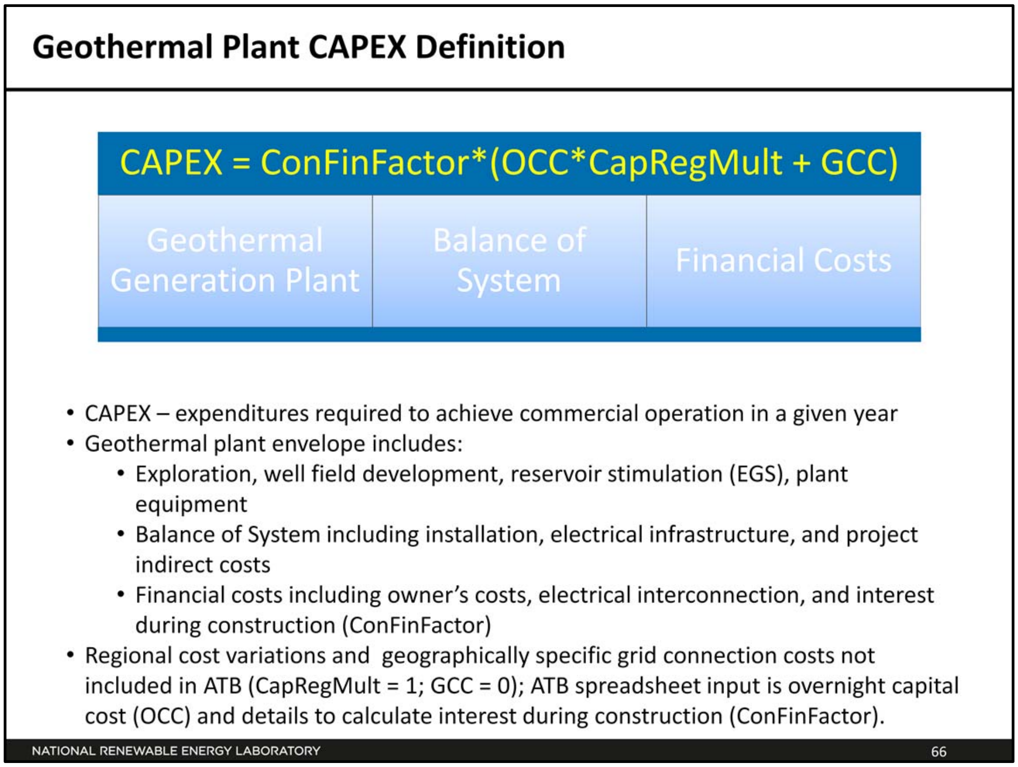
References

Augustine, C. (2011). Updated U.S. Geothermal Supply Characterization and Representation for Market Penetration Model Input. 103 pp.; NREL Report No. TP-6A2-47459.

Robert, B. (2009). Geothermal Resource of the United States: Locations of Identified Hydrothermal Sites and Favorability of Deep Enhanced Geothermal Systems (EBS). National Renewable Energy Laboratory. http://www.nrel.gov/gis/pdfs/National%20Geothermal%20EGS%20Hydrothermal%20%202009.pdf

U.S. Department of Energy. (2012). Geothermal Energy Technology Evaluation Model (GETEM). http://energy.gov/sites/prod/files/2014/02/f7/geothermal_electricity_technology_evaluation_model_may_2011.pdf

Williams, C.; Reed, M.; Mariner, R.; DeAngelo, J.; Galanis, S. (2008). Assessment of moderate- and high-temperature geothermal resources of the United States: U.S. Geological Survey Fact Sheet 2008-3082.



- CAPEX in ATB based on GETEM model results using resource attributes (estimated reservoir temperature, depth, and potential) at each site.
- CAPEX in ATB does not explicitly represent regional variants associated with labor rates, material costs, etc. or geographically determined spur line costs.

- CAPEX represents total expenditure required to achieve commercial operation in a given year. Plant envelope defined to include the following based on GETEM component cost calculations and (Beamon and Leff, 2013):
  - Geothermal Generation Plant including
    - exploration (including exploration at "unsuccessful" sites), confirmation drilling, well field development, reservoir stimulation (EGS), and plant construction
    - power plant equipment, well-field equipment and components for wells (including dry/non-commercial wells)
  - Balance of System including
    - electrical infrastructure such as transformers, switchgear and electrical system connecting turbines to each other and to control center
    - project indirect costs including engineering, distributable labor and materials, construction management start up and commissioning, and contractor overhead costs, fees and profit.
  - Financial Costs
    - owner's costs such as development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, property taxes during construction
    - onsite electrical equipment (e.g., switchyard), a nominal-distance spur line (<1 mi), and necessary upgrades at a transmission substation; distance-based spur line cost (GCC) not included in ATB.
    - interest during construction estimated based on 3-year duration accumulated 10%/10%/80% at half-year intervals and 8% interest rate
      - ATB spreadsheet input is Overnight Capital Cost (OCC) and details to calculate interest during construction (ConFinFactor).

Standard Scenarios Model Results
- CAPEX in ATB does not represent regional variants (CapRegMult) associated with labor rates, material costs, etc., and neither does ReEDS
- CAPEX in ATB does not include geographically determined spur line (GCC) from plant to transmission grid, and neither does ReEDS

References
Beamon, A.; Leff. M. (2013). EOP III Task 1606, Subtask 3 – Review of Power Plant Cost and Performance Assumptions for NEMS. Prepared by SAIC Energy, Environment & Infrastructure, LLC for the Energy Information Administration, Office of Energy Analysis. http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf

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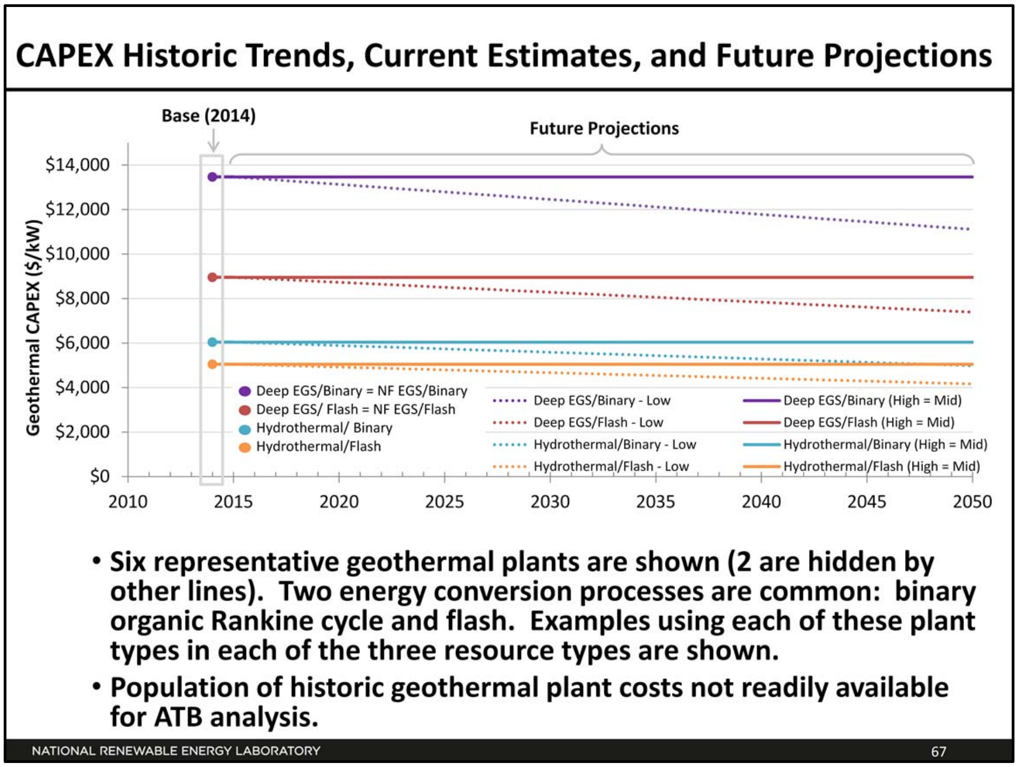
U.S. Department of Energy. (2012). Geothermal Energy Technology Evaluation Model (GETEM). http://energy.gov/eere/geothermal/geothermal-electricity-technology-evaluation-model



- For illustration in ATB, six representative geothermal plants are shown. Two energy conversion processes are common: binary organic Rankine cycle and flash. Examples using each of these plant types in each of the three resource types, hydrothermal (hydro), near-hydrothermal field EGS (NF-EGS) and deep EGS, are shown.
- Costs are for new or "greenfield" hydrothermal projects, not for re-drilling or additional development/capacity additions at an existing site.
- Binary organic Rankine cycle plants use a heat exchanger to transfer geothermal energy to the steam turbine generator; this technology generally applies to lower temperature systems. Due to the increased number of components, lower temperature operation, and general requirement for a number of wells to be drilled for a given power output, these systems have higher CAPEX than flash systems.
- Flash plants create steam directly from the thermal fluid through a pressure change; this technology generally applies to higher temperature systems. Due to the reduced number of components, higher temperature operation, these systems generally produce more power per well reducing drilling costs. These systems generally have lower CAPEX than binary systems.
- Characteristics for the six example plants representing current technology were developed based on discussion with industry stakeholders (GTO internal). The CAPEX estimates were estimated using GETEM. CAPEX for NF-EGS and EGS are equivalent. The table below shows the range of OCC associated with the resource characteristics for potential sites throughout the U.S.
- Projection of future geothermal plant CAPEX is based on minimum learning rates as implemented in AEO 2015, 10% by 2035 and extrapolated to 2050.

Standard Scenario Model Results

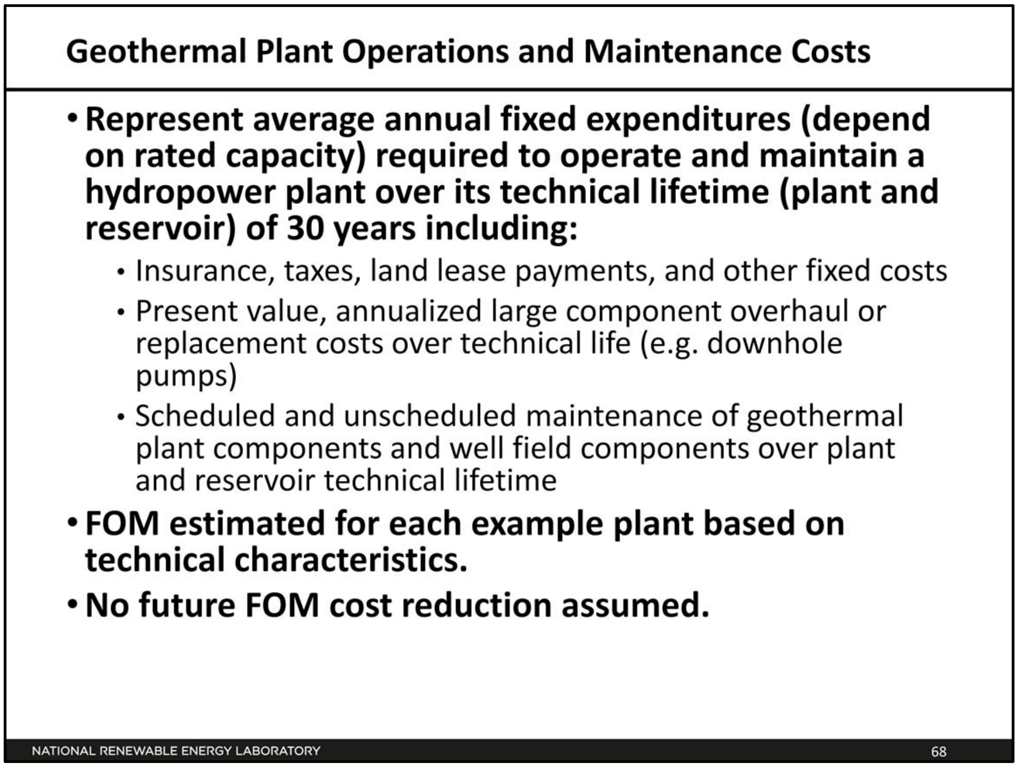
- ReEDS represents cost and performance for hydrothermal, NF-EGS and EGS potential in five bins for each of 134 geographic regions resulting in greater CAPEX range in the reference supply curve than what is shown in examples in ATB.

Future ATB Representation Under Consideration

- For this version of the ATB, future geothermal CAPEX are assumed to be the same as current costs. It is anticipated that ongoing GTO-directed analysis will improve this assumption for future versions of the ATB.

References

- Mines, G.; Nathwani, J. (2013). Geothermal Electricity Technology Evaluation Model. U.S. Department of Energy, Geothermal Technologies Office 2013 Peer Review Http://www4.eere.energy.gov/geothermal/sites/default/files/documents/mines_getem_peer2013.pdf
- EIA (2015). Annual Energy Outlook.



- Represent average annual fixed expenditures (depend on rated capacity) required to operate and maintain a hydropower plant over its technical lifetime (plant and reservoir) of 30 years including:
  - Insurance, taxes, land lease payments, and other fixed costs
  - Present value, annualized large component overhaul or replacement costs over technical life (e.g. downhole pumps)
  - Scheduled and unscheduled maintenance of geothermal plant components and well field components over plant and reservoir technical lifetime
- GETEM used to estimate FOM for each of six representative plants. Characteristics for the six example plants representing current technology were developed based on discussion with industry stakeholders (GTO internal). FOM for NF-EGS and EGS are equivalent.
- No future FOM cost reduction assumed in this edition of ATB

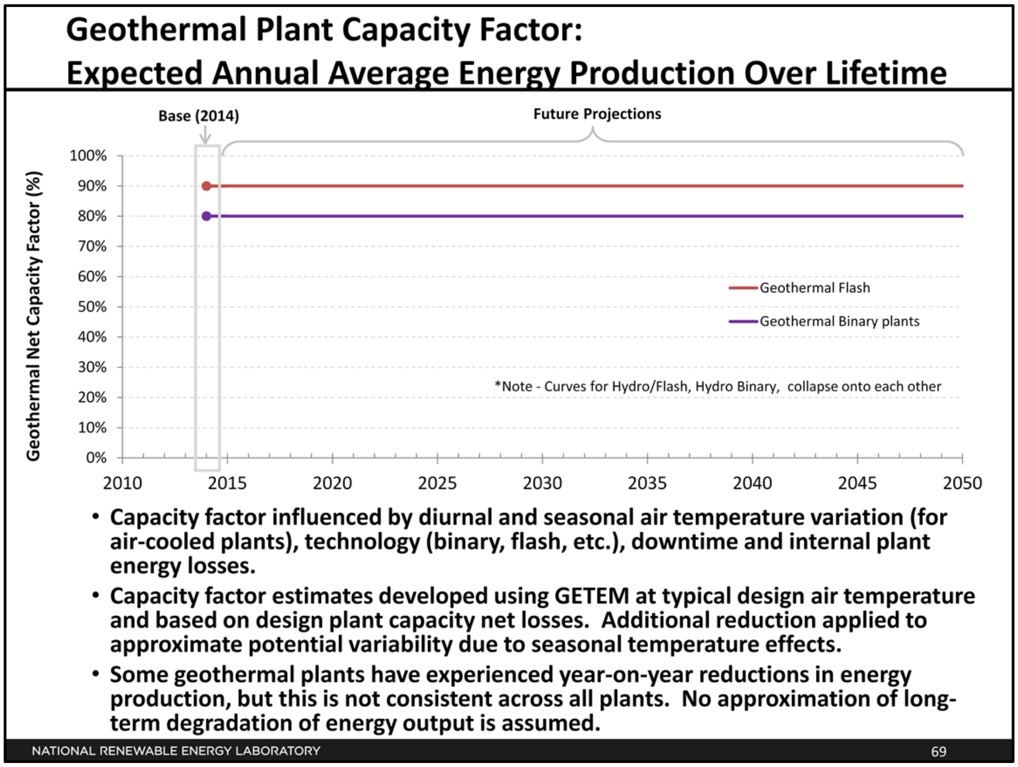
Standard Scenarios Model Results

- ReEDS Version 2016.1 standard scenario model results use FOM from AEO 2014 for all geothermal resource types and technologies.

References

U.S. Department of Energy. (2012). Geothermal Energy Technology Evaluation Model (GETEM). http://energy.gov/sites/prod/files/2014/02/f7/geothermal_electricity_technology_evaluation_model_may_2011.pdf

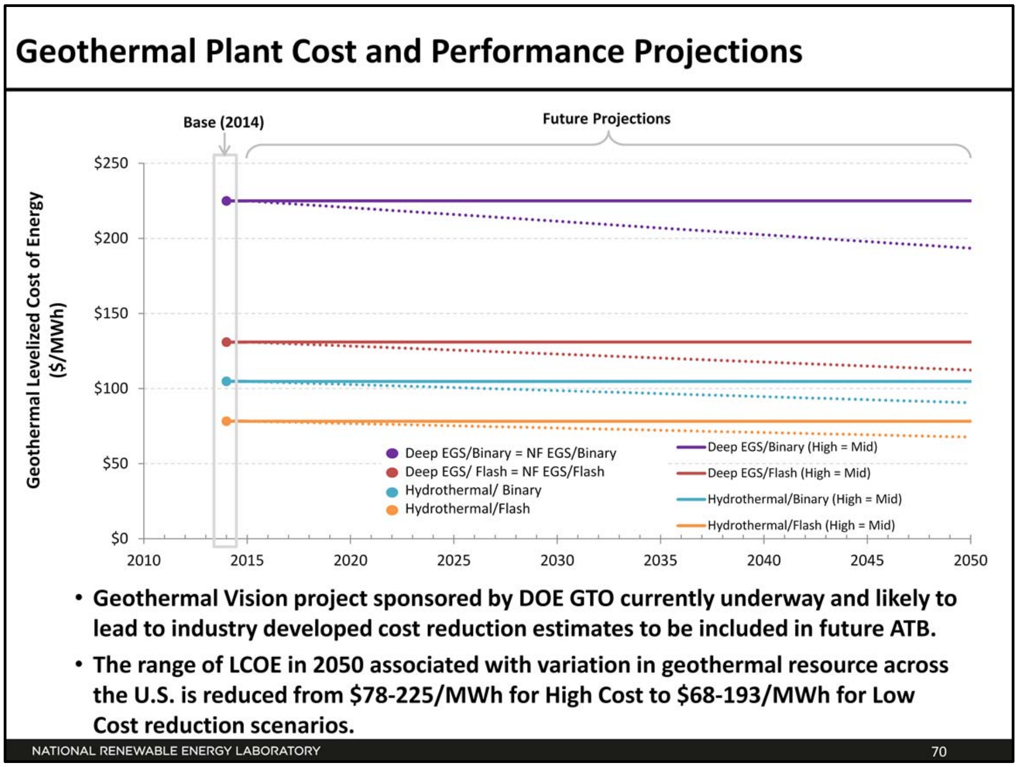
U.S. Energy Information Administration, U.S. Department of Energy (EIA). (2014a). *Annual Energy Outlook 2014 with Projections to 2040*. DOE/EIA-0383(2014). Washington, D.C.: U.S. Department of Energy Office of Integrated and International Energy Analysis. http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf



- Capacity factor represents expected annual average energy production divided by annual energy production assuming the plant operates at rated capacity for every hour of the year. Intended to represent long-term average over technical lifetime of plant and does not represent inter-annual variation in energy production.
- Capacity factor influenced by diurnal and seasonal air temperature variation (for air-cooled plants), technology (binary, flash, etc.), downtime and internal plant energy losses.
- Capacity factor estimates developed using GETEM at typical design air temperature and based on design plant capacity net losses. Additional reduction applied to approximate potential variability due to seasonal temperature effects.
- Some geothermal plants have experienced year-on-year reductions in energy production, but this is not consistent across all plants. No approximation of long-term degradation of energy output is assumed.
- Ongoing work at NREL and INL is helping to improve capacity factor estimates for geothermal plants. As their work progresses, it will be incorporated into future versions of the ATB.

References

U.S. Department of Energy. (2012). Geothermal Energy Technology Evaluation Model (GETEM). http://energy.gov/sites/prod/files/2014/02/f7/geothermal_electricity_technology_evaluation_model_may_2011.pdf



- Thorough literature review for hydrothermal geothermal technologies or EGS technologies cost reduction has not been conducted. The Low Cost case implements minimum learning of 10% by 2035 (AEO 2015) and extrapolates through 2050. The site-specific nature of geothermal plant cost, the relative maturity of hydrothermal plant technology and the very early stage development of EGS technologies make cost projections difficult.
- Geothermal Vision project sponsored by DOE GTO currently underway and likely to lead to industry developed cost reduction estimates to be included in future ATB.
- Areas identified as having potential cost reduction opportunities include:
    - development of exploration and characterization tools, which reduce well-field costs through risk reduction by locating and characterizing low- and moderate-temperature hydrothermal systems prior to drilling.
    - high-temperature tools and electronics for geothermal subsurface operations
    - novel or mixed working fluids in binary power plant designed to increase plant efficiency
    - advanced drilling system using flames or lasers to drill through rock; drilling steering technology; and other technologies to reduce drilling costs

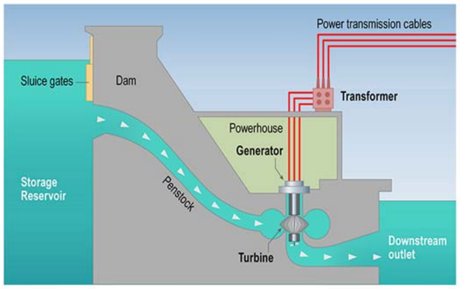
Future ATB Representation Under Consideration

- Low cost scenario reflecting technology improvements to Hydrothermal geothermal plants by 2020 and to EGS plants by 2030 have been developed.

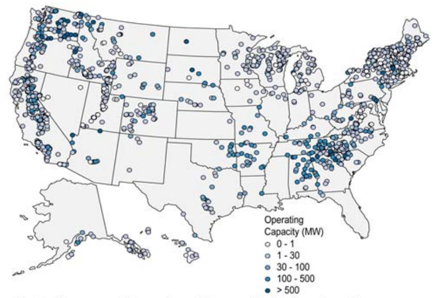
9. Hydropower Plants: Upgrades to Existing Facilities, Powering Non-Powered Dams, New Stream-reach Development

Note: pumped storage hydropower is considered a storage technology in ATB and will be addressed in future years. Pumped storage hydropower, and other storage technologies, are represented in Standard Scenarios Model Results from ReEDS model.

Hydropower – Upgrades to Existing Facilities



Source: NREL, 2012, Renewable Electricity Futures



Data Source: Homeland Security Infrastructure Program 2010

- **Hydropower technologies have produced electricity in the U.S. for over a century.**
- **As plants reach a license renewal period, upgrades to existing facilities to increase capacity or energy output are typically considered.**
- **Total potential: 6.9 GW / 24 TWh at about 1800 facilities**
- **Capital Expenditure (CAPEX) for each facility based on direct estimates where available.**
- **Capacity factor based on actual 10-year average energy production**

- Upgrades of existing facilities are included in this edition of ATB and are implemented as described in Hydropower Vision (DOE 2016). At individual facilities, investments can be made to improve the efficiency of existing generating units through overhauls, generator rewinds, or turbine replacements; such investments are known collectively as "upgrades" and are reflected in ATB as increases to plant capacity.
- Upgrade potential based on DOI, USACE, TVA and HAP case studies of existing facilities that estimate 6.9 GW/24 TWh at about 1800 facilities.
- Capital Expenditure (CAPEX) for each existing facility based on direct estimates (USBR HMI study) where available. Costs at non-reclamation plants were developed using INL (2003).
  $\text{Cost} = (277 * ExpansionMW^{-0.3}) + (2230 * ExpansionMW^{-0.19})$
- Capacity factor based on actual 10-year average energy production reported in EIA 923 forms. Hydropower facilities are typically operated to meet electric system operation and other reservoir management needs using their dispatch capability.
- No future cost reductions projections assumed.
- Upgrade cost and performance not illustrated in subsequent slides for simplicity in presentation. Upgrades are often among the lowest cost new capacity resource, with the modeled costs for individual projects ranging from $800/kW to nearly $20,000/kW. This differential results from significant economies of scale from project size, wherein larger capacity plants are less expensive to upgrade on a $/kW basis than smaller projects. While the smallest projects in the U.S. can be as small as 10 to 100kW, the bulk of upgrade potential is from large facilities. The average cost of the upgrade resource is approximately $1,500/kW.

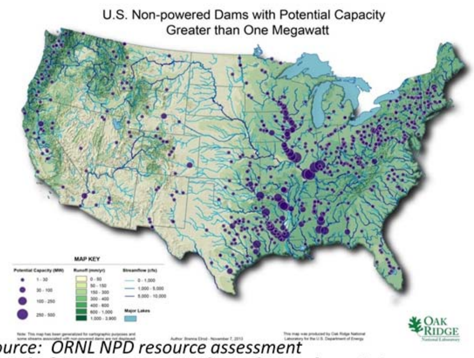
Standard Scenarios Model Results

- ReEDS model times upgrade potential availability with re-licensing date and or plant age (50 years).

References

- DOI (Department of the Interior) et al. (2007), Potential Hydroelectric Development at Existing Federal Facilities, for Section 1834 of the Energy Policy Act of 2005, Department of the Interior.
- EIA (Energy Information Administration). (2013). 860, http://www.eia.gov/electricity/data/eia860/
- Reclamation (U.S. Bureau of Reclamation). (2011). Hydropower Resource Assessment at Existing Reclamation Facilities, Denver, CO, March 2011.
- USACE (U.S. Army Corps of Engineers). (1983). National Hydroelectric Power Resources Study, Report No. IWR-82-H-1, Washington, D.C.
- USACE (U.S. Army Corps of Engineers). (2011). Hydroelectric Power Assessment—State of Hawaii. http://energy.hawaii.gov/wp-content/uploads/2011/10/HydroelectricPowerAssess.pdf.
- TVA and HAP, INL 2003 cost report.
- DOE (expected 2016) Hydropower Vision.

Hydropower – Powering Non-Powered Dams



Source: ORNL NPD resource assessment

- **Dams are often built for purposes other than electricity generation. As a result there are a number of existing dams without power conversion technology that could be modified.**
- **Total potential = 5.6 GW / 31 TWh at over 54,000 dams, but the majority of the potential, 5GW (90% of resource capacity) is associated with about 500 dams.**
- **Design capacity and flow rate dictate capacity and energy generation potential. All facilities assumed sized for 30% exceedance of flow rate based on long-term, average monthly flow rates.**

- Nationally, more than 80,000 dams exist which do not produce power. This dataset from the National Inventory of Dams (NID) was filtered to remove dams with erroneous flow and geographic data, or dams whose data could not be resolved to a satisfactory level of detail (Hadjerioua, et al., 2012). This initial assessment of 54,391 dams resulted in 12 GW of capacity.
- A new methodology for sizing potential hydropower facilities that was developed for the New-Stream Reach Development resource (Kao et al., 2014) was applied to non-powered dams. Final resource potential estimated to be 5.9 GW / 33 TWh at over 54,000 dams. This method is summarized below.
- About 600 existing facilities were evaluated to assess resource potential (capacity) and energy generation potential (CF). For each facility a design capacity, average monthly flow rate over a 20-year period and design flow rate exceedance level of 30% are assumed. The exceedance level represents the fraction of time that the design flow is exceeded. This parameter can be varied and results in different capacity and energy generation for a given site. The value of 30% was chosen based on industry rules of thumb. The capacity factor for a given facility is determined by these design criteria.
- CAPEX for each facility is based on statistical analysis of historic plant data from 1980 to 2015 as a function of key design parameters, plant capacity and hydraulic head (O'Connor et al., 2015).
- $\text{Cost} = (11{,}489{,}245 * P^{0.976} * H^{-0.24}) + (310{,}000 * P)$

Standard Scenarios Model Results
- ReEDS Version 2016.1 standard scenario model results restrict the resource potential to sites greater than 500 kW resulting in 5.1 GW / 28 TWh at 667 dams.

References

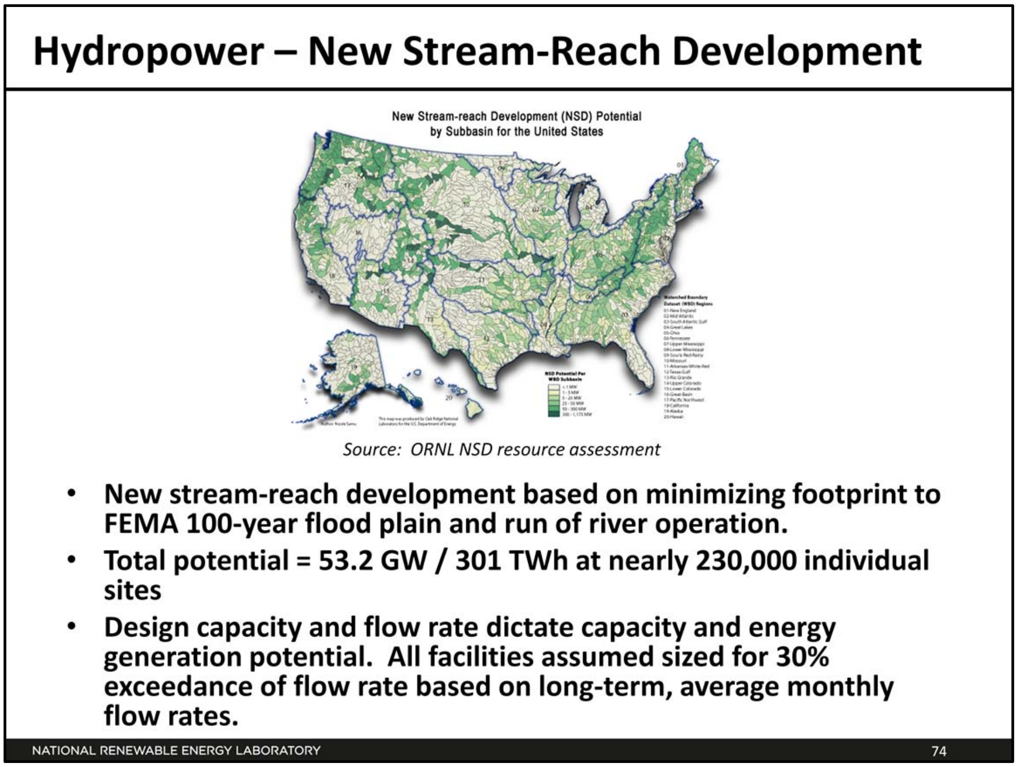
Hadjerioua, B. et al. (2012). An Assessment of Energy Potential at Non-Powered Dams in the United States. Prepared by Oakridge National Laboratory for the U.S. Department of Energy. http://www1.eere.energy.gov/water/pdfs/npd_report.pdf

Hall et al. (2003). Estimation of Economic Parameters of U.S. Hydropower Resources. Idaho National Laboratory. http://www1.eere.energy.gov/water/pdfs/doewater-00662.pdf.

Kao et al. (2014). New Stream-reach Development: A Comprehensive Assessment of Hydropower Energy Potential in the United States. Prepared by Oakridge National Laboratory for the U.S. Department of Energy. New Stream-reach Development: A Comprehensive Assessment of Hydropower Energy Potential in the United States

O'Connor, P.W., S.T. DeNeale, D.R. Chalise, A. Maloof (2015). Hydropower Baseline Cost Modeling, Version 2. ORNL/TM-2015/471. Oak Ridge, TN: Oak Ridge National Laboratory.

Oakridge National Laboratory. Hydropower Resource Map expected publication 2015.



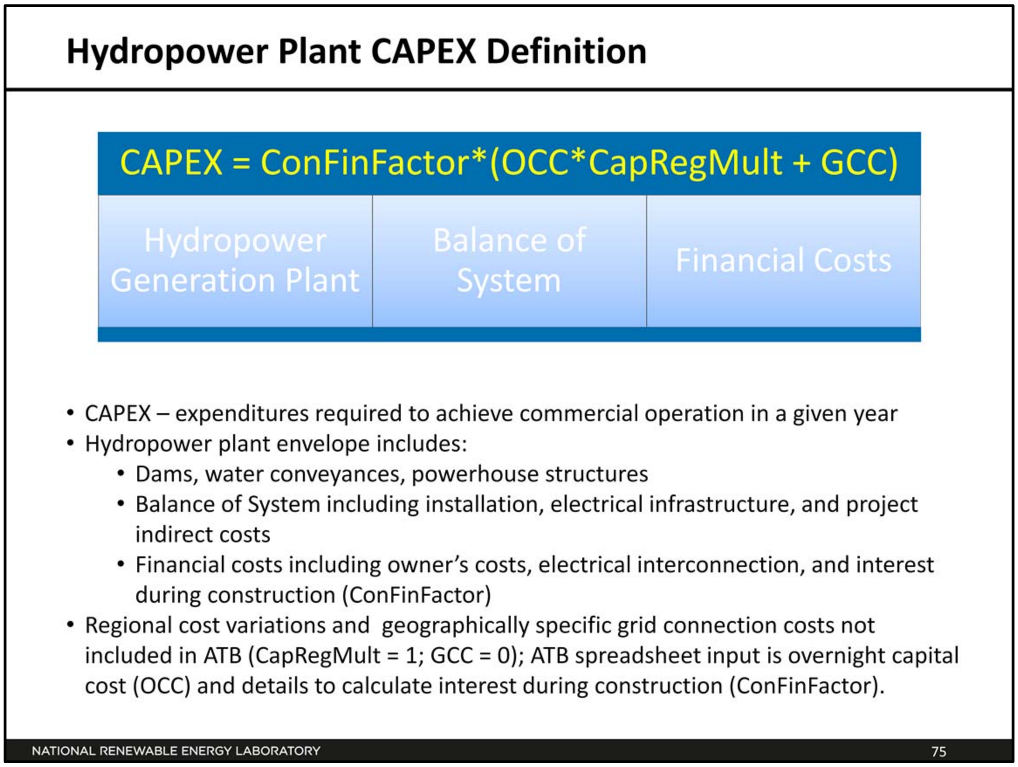
- Resource potential estimated to be 53.2 GW / 301 TWh at nearly 230,000 individual sites (Kao et al., 2014) after accounting for exclusions such as national parks, wild and scenic rivers, and wilderness areas.
- About 8500 stream reaches were evaluated to assess resource potential (capacity) and energy generation potential (CF). For each stream reach a design capacity, average monthly flow rate over 20-year period and design flow rate exceedance level of 30% are assumed. The exceedance level represents the fraction of time that the design flow is exceeded. This parameter can be varied and results in different capacity and energy generation for a given site. The value of 30% was chosen based on industry rules of thumb. The capacity factor for a given facility is determined by these design criteria. Plant sizes range from kW to multi-MW (Kao et al., 2014).
- Resource assessment approach designed to minimize footprint of hydropower facility by restricting inundation area to FEMA 100 year flood plain.
- New hydropower facilities are assumed to apply run of river operation strategies. Run of river operation means that flow rate into reservoir is equal to flow rate out of facility. These facilities do not have dispatch capability.
- CAPEX for each facility is based on statistical analysis of historic plant data from 1980 to 2015 as a function of key design parameters, plant capacity and hydraulic head (O'Connor et al., 2015).
- $\mathrm{Cost} = (9{,}605{,}710 * P^{0.977} * H^{-0.126}) + (610{,}000 * P^{0.7})$

Standard Scenarios Model Results

- ReEDS Version 2016.1 standard scenario model results restrict the resource potential to sites greater than 1 MW resulting in 30.1 GW / 176 TWh at nearly 8000 sites.

References

- Kao et al. (2014). New Stream-reach Development: A Comprehensive Assessment of Hydropower Energy Potential in the United States. Prepared by Oakridge National Laboratory for the U.S. Department of Energy. New Stream-reach Development: A Comprehensive Assessment of Hydropower Energy Potential in the United States
- O'Connor, P.W., S.T. DeNeale, D.R. Chalise, A. Maloof (2015). Hydropower Baseline Cost Modeling, Version 2. ORNL/TM-2015/471. Oak Ridge, TN: Oak Ridge National Laboratory.



- CAPEX for each facility is based on statistical analysis of historic plant installation costs from 1980 to 2015 (O'Connor et al., 2015b). Among the many data sources pursued, the most significant contributions came from license applications filed with the Federal Energy Regulatory Commission's (FERC), IIR's PECWeb database, and a series of reports retrospectively detailing the activities of the Department of Energy's (DOE) small hydropower development efforts in the late 1970s and early 1980s. Additional data sources include industry contacts and reports from various hydropower stakeholders.

- CAPEX in ATB does not explicitly represent regional variants associated with labor rates, material costs, etc. or geographically determined spur line costs.

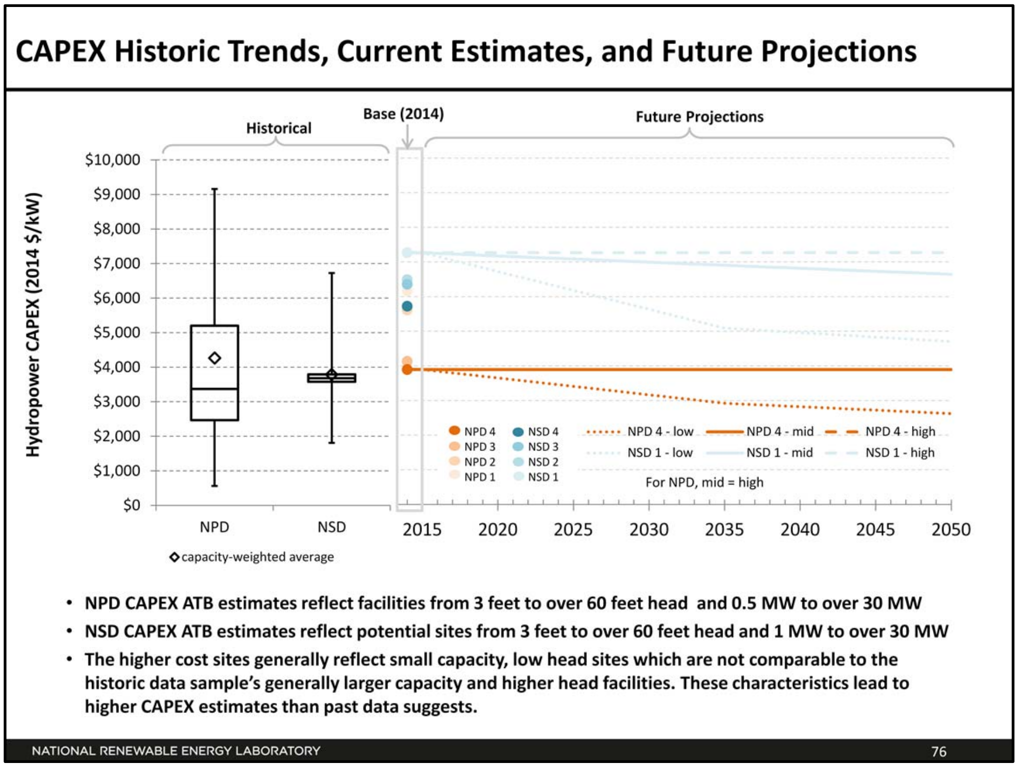
- CAPEX represents total expenditure required to achieve commercial operation in a given year. Plant envelope defined to include the following (Beamon and Leff, 2013; O'Connor et al., 2015a)
    - Hydropower Generation Plant including
        - Civil works such as site preparation, dams and reservoirs, water conveyances, powerhouse structures
        - Equipment such as powertrain, ancillary plant electrical and mechanical systems
    - Balance of System including
        - operation and maintenance infrastructure
        - electrical infrastructure such as transformers, switchgear and electrical system connecting turbines to each other and to control center
        - project indirect costs including environmental mitigation and regulatory compliance, engineering, distributable labor and materials, construction management start up and commissioning, and contractor overhead costs, fees and profit.
    - Financial Costs
        - owner's costs such as development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, property taxes during construction
        - onsite electrical equipment (e.g., switchyard), a nominal-distance spur line (<1 mi), and necessary upgrades at a transmission substation; distance-based spur line cost (GCC) not included in ATB.
        - interest during construction estimated based on 3-year duration accumulated 10%/10%/80% at half-year intervals and 8% interest rate
            - ATB spreadsheet input is Overnight Capital Cost (OCC) and details to calculate interest during construction (ConFinFactor).

Standard Scenarios Model Results
- CAPEX in ATB does not represent regional variants (CapRegMult) associated with labor rates, material costs, etc., and neither does ReEDS
- CAPEX in ATB does not include geographically determined spur line (GCC) from plant to transmission grid, and neither does ReEDS

References
Beamon, A.; Leff. M. (2013). EOP III Task 1606, Subtask 3 – Review of Power Plant Cost and Performance Assumptions for NEMS. Prepared by SAIC Energy, Environment & Infrastructure, LLC for the Energy Information Administration, Office of Energy Analysis.
http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf

O'Connor, P.W., Zhang, Q. F., S.T. DeNeale, D.R. Chalise, Centurion, E (2015a). Hydropower Baseline Cost Modeling. ORNL/TM-2015/14. Oak Ridge, TN: Oak Ridge National Laboratory

O'Connor, P.W., S.T. DeNeale, D.R. Chalise, A. Maloof (2015b). Hydropower Baseline Cost Modeling, Version 2. ORNL/TM-2015/471. Oak Ridge, TN: Oak Ridge National Laboratory



- For illustration in ATB, all potential NPD and NSD sites were first binned by both head and capacity. Analysis of these bins provided groupings that represented the most realistic conditions for future hydropower deployment. The design values of these four reference NPD and four reference NSD plants are shown below. The full range of resource and design characteristics are in the ATB spreadsheet.
- The reference plants shown below were developed using the average characteristics (weighted by capacity) of the resource plants within each set of ranges. For example, NPD 1 is constructed from the capacity-weighted average values of NPD sites between 3-30 feet of head and 0.5-10 MW of capacity.
- The weighted average values were used as input to the cost formulas (O'Connor et al., 2015) in order to calculate site CAPEX and O&M costs.

	Resource Characteristics Ranges		Weighted Average Values			Calculated Plant Values	
Plants	**Head (feet)**	**Capacity (MW)**	**Head (feet)**	**Capacity (MW)**	**Capacity Factor**	**ICC (2014$/kW)**	**O&M (2014$/kW)**
NPD 1	3-30	0.5-10	15.4	4.8	0.62	$ 5,937.86	$ 111.14
NPD 2	3-30	10+	15.9	82.2	0.64	$ 5,404.59	$ 30.58
NPD 3	30+	0.5-10	89.6	4.2	0.60	$ 3,976.71	$ 118.05
NPD 4	30+	10+	81.3	44.7	0.60	$ 3,749.35	$ 40.32
NSD 1	3-30	1-10	15.7	3.7	0.66	$ 6,997.72	$ 124.36
NSD 2	3-30	10+	19.6	44.1	0.66	$ 6,247.04	$ 40.55
NSD 3	30+	1-10	46.8	4.3	0.62	$ 6,118.62	$ 116.99
NSD 4	30+	10+	45.3	94.0	0.66	$ 5,508.15	$ 28.78

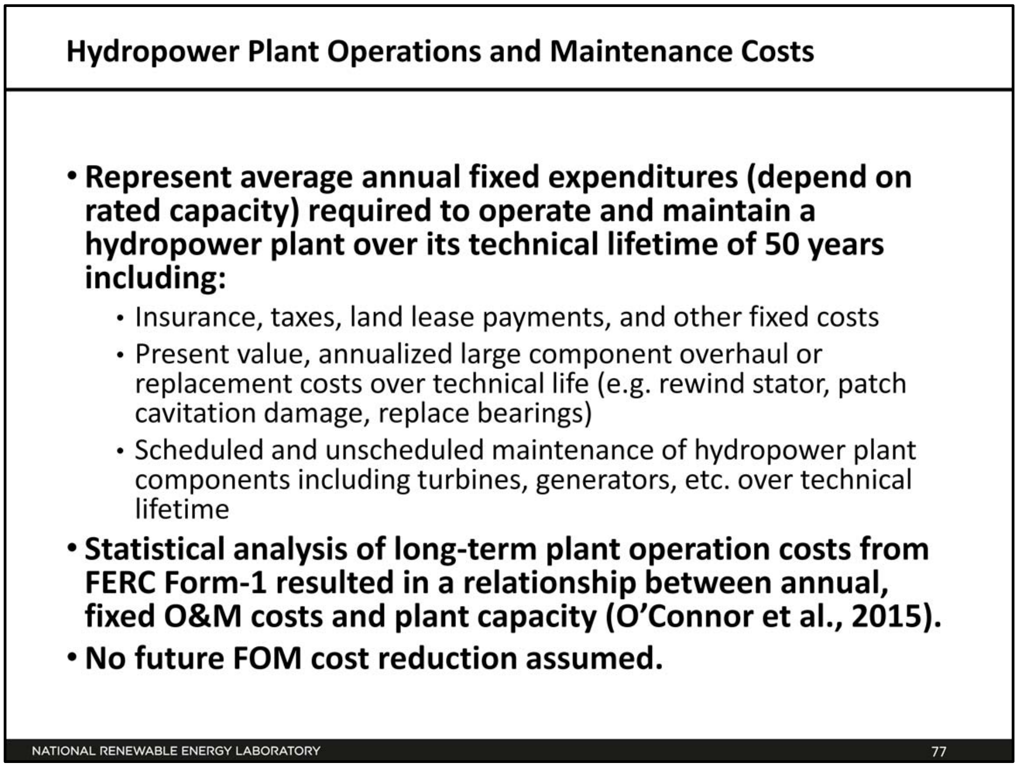
- Actual and proposed NPD and NSD CAPEX from 1981-2014 (from O'Connor et al. 2015) are shown in box and whiskers format (bar represents median, box represents 25th and 75th percentile, whiskers represent minimum and maximum; diamond represents capacity weighted average) for comparison to ATB current CAPEX estimates and future projections.
- NPD CAPEX ATB estimates range from $3,700/kW to nearly $6,000/kW; the higher cost sites generally reflect very smaller capacity (<10 MW), low head sites which have fewer analogues in the historical data, but these characteristics result in higher CAPEX.
- NSD CAPEX in ATB ranges from $5,500/kW to $6,900/kW; in general, NSD potential represents smaller capacity facilities with lower head than most historical data represents. These characteristics lead to higher CAPEX estimates than past data suggests.

Standard Scenarios Model Results

- ReEDS Version 2015.1 standard scenario model results use resource/cost supply curves representing estimates at each individual facility (~700 NPD, ~8000 NSD).
- ReEDS represents cost and performance for NPD and NSD potential in five bins for each of 134 geographic regions resulting in CAPEX range from $2300/kW to $66,000/kW for NPD resource and from $5500/kW to $13,000/kW for NSD.
- ReEDS represents cost and performance for NPD and NSD potential in five bins for each of 134 geographic regions resulting in CF range from 38% to 80% for NPD resource and from 53% to 81% for NSD.

References

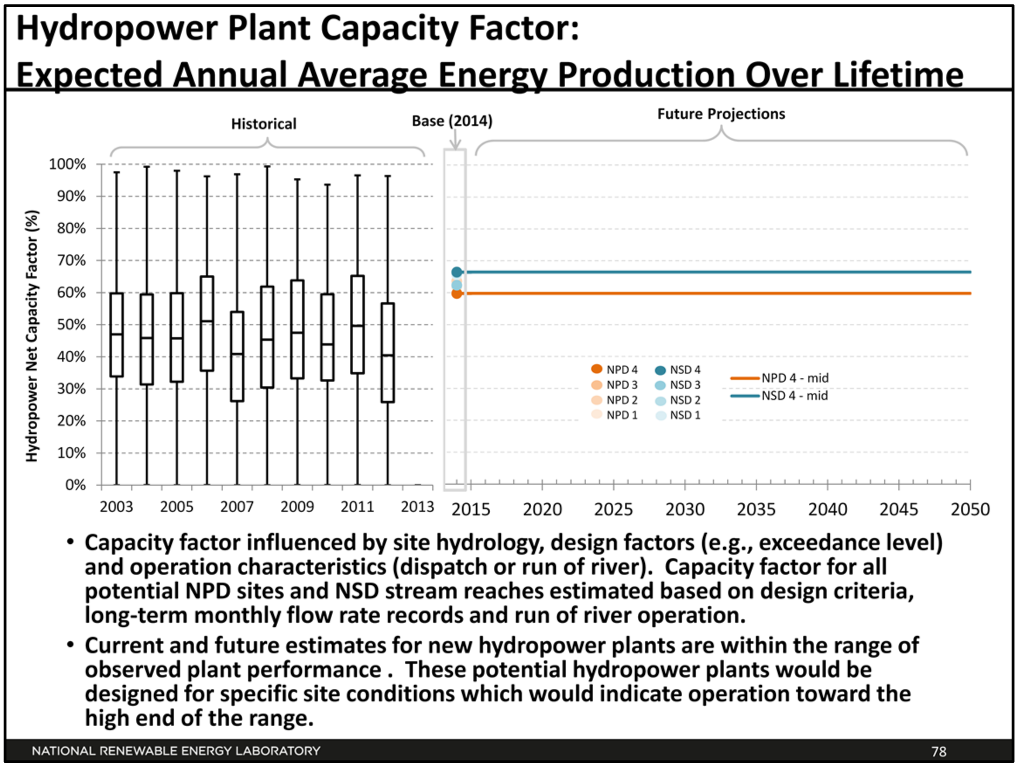
- O'Connor, P.W., S.T. DeNeale, D.R. Chalise, A. Maloof (2015). Hydropower Baseline Cost Modeling, Version 2. ORNL/TM-2015/471. Oak Ridge, TN: Oak Ridge National Laboratory.



- Represent average annual fixed expenditures (depend on rated capacity) required to operate and maintain a hydropower plant over its technical lifetime of 50 years including:
    - Insurance, taxes, land lease payments, and other fixed costs
    - Present value, annualized large component overhaul or replacement costs over technical life (e.g. rewind stator, patch cavitation damage, replace bearings)
    - Scheduled and unscheduled maintenance of hydropower plant components including turbines, generators, etc. over technical lifetime
- Statistical analysis of long-term plant operation costs from FERC Form-1 resulted in a relationship between annual, fixed O&M costs and plant capacity (O'Connor et al., 2015).
    - $Lessor\ of \begin{cases} Annual\ O\&M\ (in\ 2014\$) = 225{,}417\ P^{0.547} \\ 2.5\%\ of\ CapEx \end{cases}$
- O&M costs for reference NPD and NSD plants shown earlier.
- No future FOM cost reduction assumed in this edition of ATB.

References

- O'Connor, P.W., S.T. DeNeale, D.R. Chalise, A. Maloof (2015). Hydropower Baseline Cost Modeling, Version 2. ORNL/TM-2015/471. Oak Ridge, TN: Oak Ridge National Laboratory.



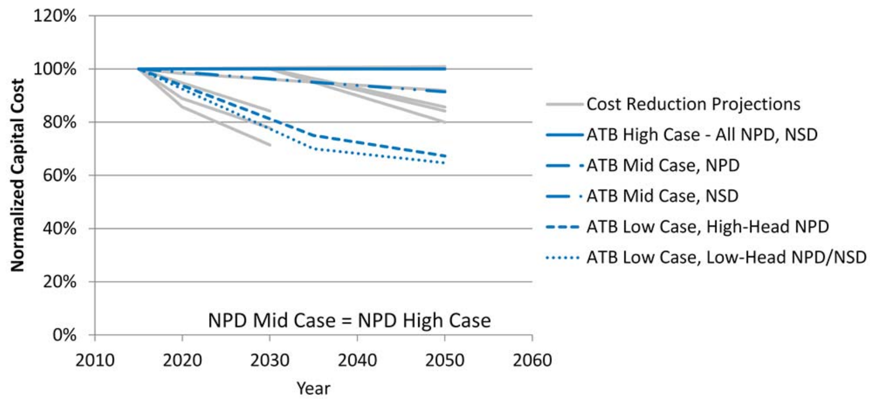
- Capacity factor represents expected annual average energy production divided by annual energy production assuming the plant operates at rated capacity for every hour of the year. Intended to represent long-term average over technical lifetime of plant and does not represent inter-annual variation in energy production.
- Capacity factor influenced by site hydrology, design factors (e.g., exceedance level) and operation characteristics (dispatch or run of river). Capacity factor for all potential NPD sites and NSD stream reaches estimated based on design criteria, long-term monthly flow rate records and run of river operation.
- For illustration in ATB, all potential NPD and NSD sites were represented with four reference plant each as described on an earlier slide.
- Actual energy production from about 200 run of river plants operating in the U.S. from 2003 to 2012 (EIA) is shown in box and whiskers format for comparison with current estimates and future projections. This sample includes some very old plants that may have lower availability and efficiency losses. It also includes plants that have been relicensed and may no longer be optimally designed for current operating regime (e.g., a peaking unit now operating as run of river). This contributes to the broad range, particularly on the low end.
- Current and future estimates for new hydropower plants are within the range of observed plant performance. These potential new hydropower plants would be designed for specific site conditions which would indicate operation toward the high end of the range.
- Inter-annual variation of hydropower plant output for run of river plants may be significant due to hydrological changes such as drought. This impact may be exacerbated by climate change over the long term.

Standard Scenarios Model Results
- ReEDS Version 2016.1 standard scenario model results use resource/cost supply curves representing estimates at each individual facility (~700 NPD, ~8000 NSD).
- ReEDS represents cost and performance for NPD and NSD potential in five bins for each of 134 geographic regions resulting in CF range from 38% to 80% for NPD resource and from 53% to 81% for NSD.
- Existing hydropower facilities in ReEDS provide dispatch capability such that their annual energy production is determined by the electric system needs by dispatching generators to accommodate diurnal and seasonal load variations and output from variable generation sources (wind and solar-PV).

References

- EIA data for historic capacity factor
- Kao et al. (2014). New Stream-reach Development: A Comprehensive Assessment of Hydropower Energy Potential in the United States. Prepared by Oakridge National Laboratory for the U.S. Department of Energy. [New Stream-reach Development: A Comprehensive Assessment of Hydropower Energy Potential in the United States]

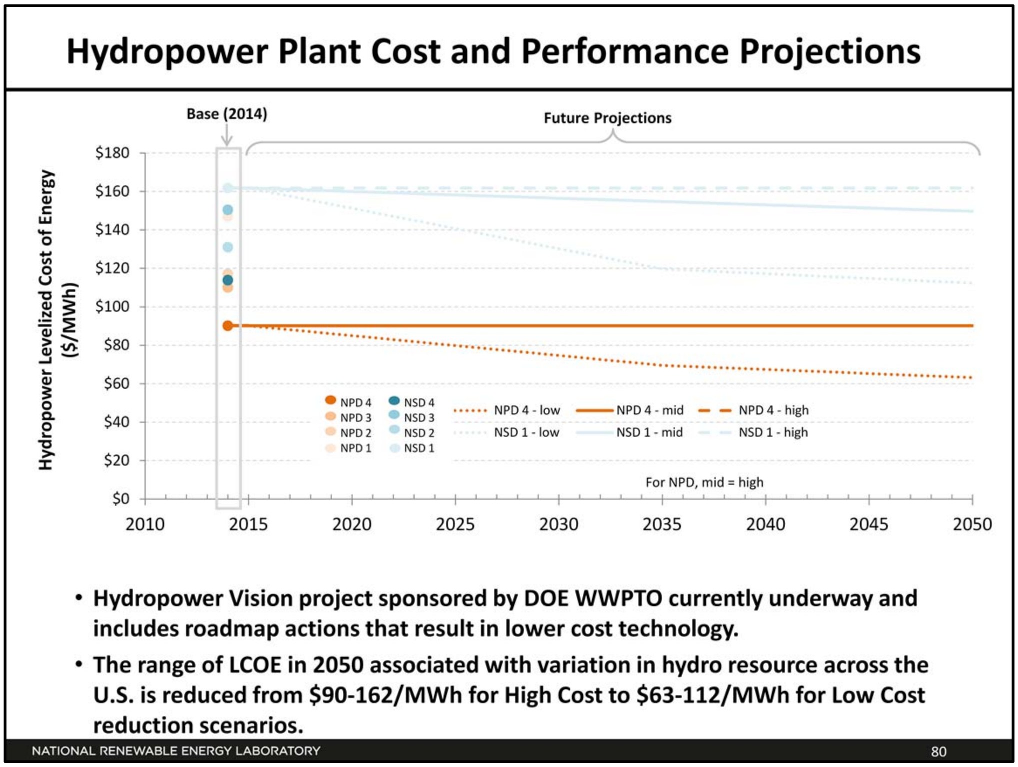
Hydropower Plant Cost and Performance Projections Methodology



- **Projections developed using bottom-up analysis of process and/or technology improvements to provide a range of future cost outcomes.**
  - Low Cost: gains achievable when pushing to the limits of potential new technologies such as modularity (in both civil structures and power train design), advanced manufacturing techniques, and materials.
  - Mid Cost: aggressive equipment standardization efforts, widespread implementation of value engineering and design/construction best practices using generally conventional technology, evolution of licensing processes.
  - High Cost: No change in CAPEX from 2015-2050

- A range of future cost outcomes was developed for the DOE Hydropower Vision (expected 2016) study using bottom-up analysis of process and/or technology improvements. The Mid and Low cost cases use a mix of inputs based on U.S. Energy Information Administration (EIA) technological learning assumptions, input from a technical team of Oak Ridge National Laboratory (ORNL) researchers, and the experience of expert hydropower consultants. Estimated 2035 cost levels are intended to provide magnitude of order cost reductions deemed to be at least conceptually possible and are meant to stimulate a broader discussion with the hydropower industry and its stakeholders that will be necessary to the future of cost reduction in the hydropower industry. Cost projections were derived independently for NPD and NSD technologies.
- ATB cost projections are compared to published literature for context. Published literature represents 7 independent published studies and 11 different cost projection scenarios within these studies. Cost reduction literature for hydropower is limited with several studies projecting no change through 2050. It is unclear whether this is represents a deliberate estimate of no future change in cost or whether no estimate has been made.
- Hydropower investment costs are very site specific and vary with type of technology. Literature reviewed to attempt to isolate perceived CAPEX reduction for resources of similar characteristics over time (e.g., estimated cost to develop the same site in 2015, 2030, and 2050 based on different technology, installation, and other technical aspects). Some studies reflect increasing CAPEX over time. These studies were excluded from this analysis based on the interpretation that rising costs reflect transition to less attractive sites as the better sites are used earlier.
- Literature estimates generally reflect hydropower facilities of sizes similar to those in represented in U.S. resource potential (i.e., exclude estimates for very large facilities). Due to limited sample size, all projections are analyzed together without distinction between type of technology. Note that although declines shown on percentage basis, the reduction is likely to vary with initial capital cost. Large reductions for moderately expensive sites may not scale to more expensive sites or to less expensive sites. Projections derived for Hydropower Vision for different technologies, Low Head NPD, High Head NPD and NSD address this simplification somewhat.
- Three different projections developed for scenario modeling as bounding levels.
  - Low Cost: gains achievable when pushing to the limits of potential new technologies such as modularity (in both civil structures and power train design), advanced manufacturing techniques, and materials.
  - Mid Cost: aggressive equipment standardization efforts, widespread implementation of value engineering and design/construction best practices using generally conventional technology, evolution of licensing processes.
  - High Cost: No change in CAPEX from 2015-2050
- References:

- EIA, Annual Energy Outlook (2015)
- Black & Veatch; (2012). Cost and Performance Data for Power Generation Technologies; prepared for NREL.
- Rocky Mountain Institute (2011) Reinventing Fire.
- IRENA (2012). Renewable Energy Technologies: Cost Analysis Series
- IEA (2008) Energy Technologies Perspectives
- IEA Energy Technology Systems Analysis Programme (2010). Technology Brief: Hydropower
- DOE (expected 2016). Hydropower Vision Study.



- Areas identified as having potential cost reduction opportunities include:
  - widespread implementation of value engineering and design/construction best practices
  - modular “drop in” systems that minimize civil works and maximize ease of manufacture
  - use of alternative materials in place of steel for water diversion (e.g., penstocks)
  - research and development on environmentally enhanced turbines to improve performance of the existing hydropower fleet
  - efficient, certain, permitting, licensing, and approval procedures

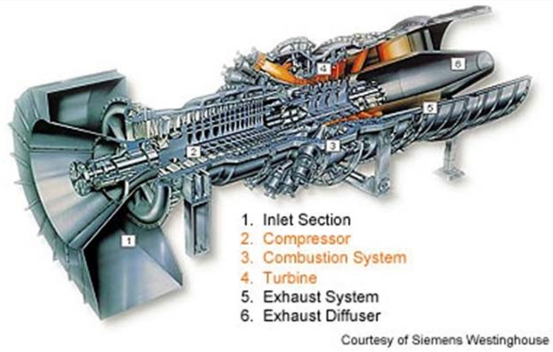
Conventional Power Plants

Conventional Technologies – Overview

- For the inaugural Annual Technology Baseline, the cost and performance of conventional technologies is taken directly from the Annual Energy Outlook, produced by the U.S. Department of Energy (DOE)’s Energy Information Administration
- The reference case does not include any carbon costs for any of the conventional technologies.
- Note that the capacity factors for conventional technologies represent the historical average across the entire U.S. fleet, by fuel type and generator type. Individual capacity factors for each plant’s actual operation will vary significantly, and new investments likely would anticipate higher capacity factors.
- In future years, the ATB cost and performance of conventional technologies will also be informed by other DOE national laboratories and published literature.

10. Natural Gas Plants

Natural Gas Power Plants – Technology Overview



The combustion (gas) turbines involve:

1. **The air compressor**, compresses and feeds it into the combustion chamber at hundreds of miles per hour.
2. **The combustion system.** A a ring of fuel injectors inject fuel into combustion chambers where it mixes with the air. The high temperature, high pressure gas stream enters and expands through the turbine.
3. **The turbine** has alternate stationary and rotating aerofoil-section blades, driven by expanding, hot combustion gas. The rotating blades drive the compressor and spin a generator to produce electricity.

Simple cycle gas turbine can achieve 20%-35% energy conversion efficiency. Future hydrogen and syngas fired gas turbine combined cycle plants are likely to achieve efficiencies of 60 percent or more. When waste heat is captured from these systems for heating or industrial purposes, the overall energy cycle efficiency could approach 80 percent.

Source: U.S. DOE "How Gas Turbine Power Plants Work"

http://energy.gov/fe/how-gas-turbine-power-plants-work

Natural Gas CapEx Required for Commercial Operation

Natural Gas Technologies	
Gas-CT	Conventional Combustion Turbine
Gas-CC	Conventional Combined Cycle
Gas-CC-CCS	Combined Cycle with carbon capture & storage (CCS)

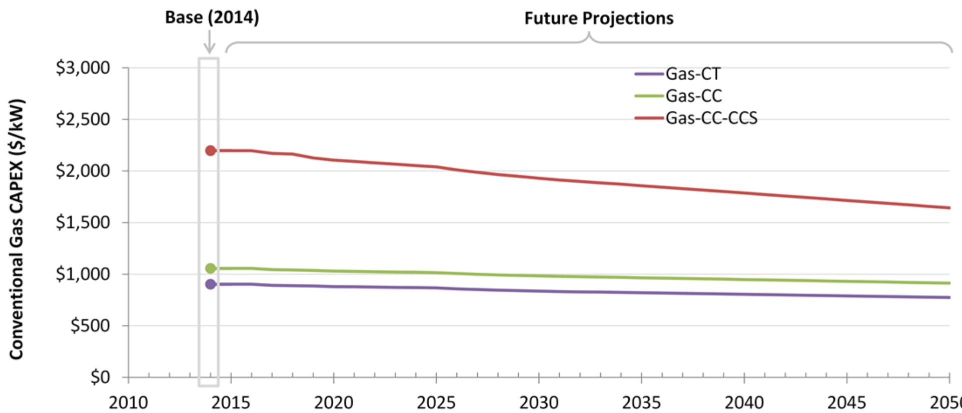
	Overnight capital cost ($/kW)	Construction financing factor	CAPEX ($/kW)
Gas-CT	$869	1.039	$903
Gas-CC	$1017	1.039	$1,056
Gas-CC-CCS	$2,115	1.039	$2,198

OCC Source: Modified from U.S. DOE EIA – Annual Energy Outlook 2016
Capital cost includes overnight capital cost plus defined transmission cost, and removes a material price index.

- **CAPEX = ConFinFactor x OCC**
- **Fuel costs are just passed through to end user**
- **Fuel costs are also taken from EIA's AEO 2016**

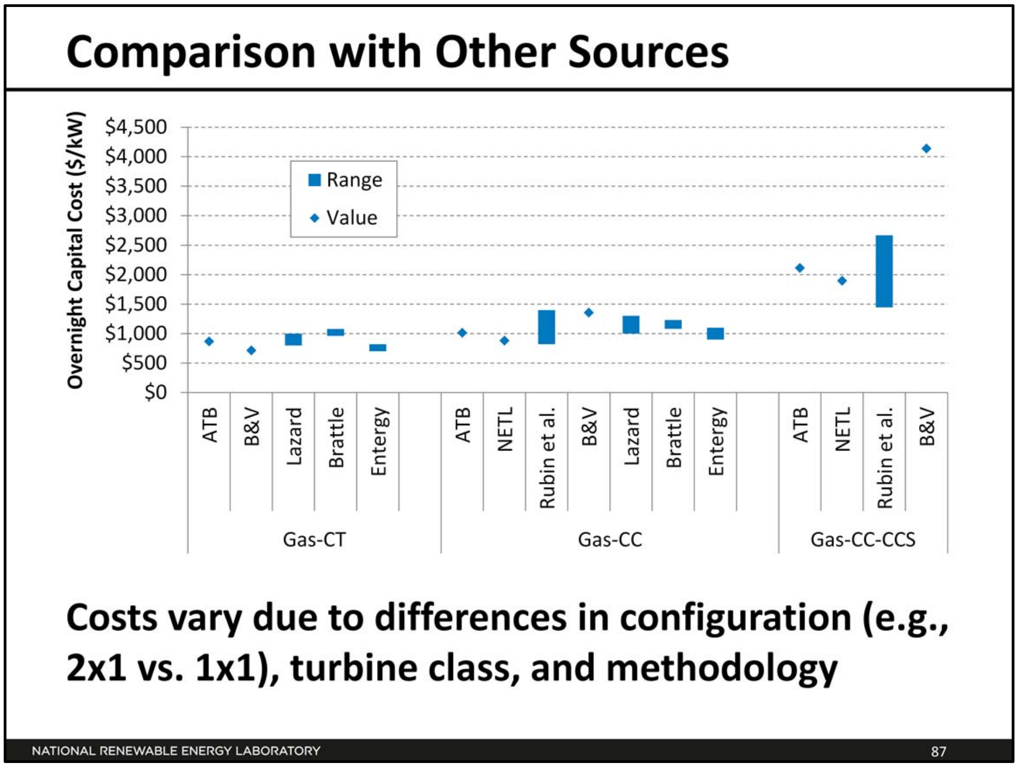
EIA reports two types of gas-CT and gas-CC technologies in the AEO: advanced and conventional. The gas-CT and gas-CC cost and performance information in the ATB is the average of the two EIA technologies. For example, the overnight capital cost for gas-cc technology in the ATB is the average of the capital cost of the advanced and conventional combined cycle technologies from the EIA's AEO.

Natural Gas - CapEx Historic Trends, Current Estimates, and Future Projections



Source: Current estimates and future projections calculated from U.S. DOE EIA – Annual Energy Outlook 2016, modified.

- **A natural gas turbine (either combustion turbine /CT or combined cycle/CC) is a well-known technology that performs close to its optimum performance. As such, EIA expects that capital expenditures will incrementally improve over time, slightly more quickly than inflation.**
- **The one exception is natural gas CC with carbon capture and storage (CCS). The U.S. Department of Energy's Fossil Energy office and the National Energy Technology Laboratory conduct research on reducing the costs and increasing the performance of the CCS technology and costs are expected to reduce over time**



Sources:
Fout et al., Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3, (2015)
http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/Rev3Vol1aPC_NGCC_final.pdf
Rubin et al., The cost of CO2 capture and storage, (2015)
http://www.sciencedirect.com/science/article/pii/S1750583615001814; preprint available at http://www.cmu.edu/epp/iecm/rubin/PDF%20files/2015/Pages%20from%20Rubin_et_al_ThecostofCCS_IJGGC_2015.pdf
Black & Veatch, Cost and Performance Data for Power Generation Technologies, (2012)
http://bv.com/docs/reports-studies/nrel-cost-report.pdf%E2%80%8E
Lazard, Levelized Cost of Energy Analysis-Version 9.0, (2015)
https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf
Newell et al., Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM, (2014)
http://www.brattle.com/system/publications/pdfs/000/005/010/original/Cost_of_New_Entry_Estimates_for_Combustion_Turbine_and_Combined_Cycle_Plants_in_PJM.pdf?1400252453
Entergy, 2015 Integrated Resource Plan, (2015) http://entergy-arkansas.com/content/transition_plan/IRP_Materials_Compiled.pdf

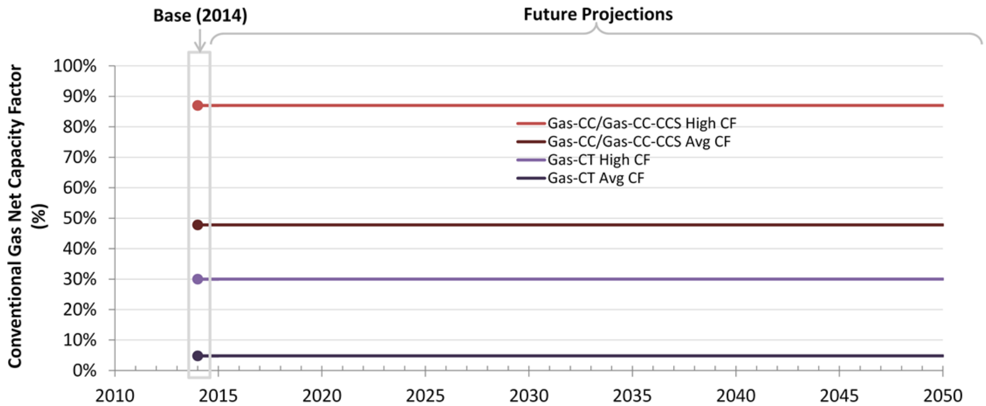
Natural Gas Operations and Maintenance Costs

- **Represents annual expenditures required to operate and maintain a natural gas power plant over its technical lifetime including:**
    - Insurance, taxes, land lease payments, and other fixed costs
    - Present value, annualized large component replacement costs over technical life
    - Scheduled and unscheduled maintenance of natural gas power plants, transformers, etc. over technical lifetime
- **Market data for comparison is limited and generally inconsistent in range of costs covered, length of historic record**
- **O&M represents anticipated lifetime operation expenditures for new technology**

__Photo credit:__ **Duke Energy**
H.F. Lee natural gas plant 1;
Goldsboro, NC
Taken on September 24, 2013

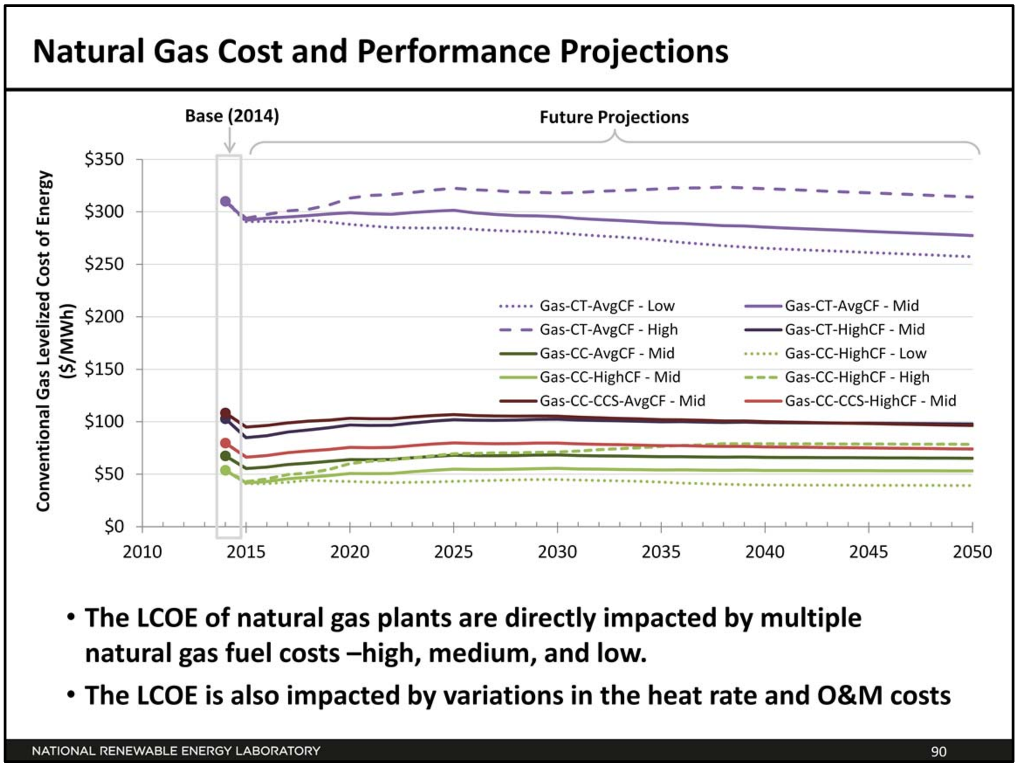
https://www.flickr.com/photos/dukeenergy/11441374433

Natural Gas – Capacity Factor: Annual Average Energy Production over Lifetime



Source: U.S. DOE EIA – Electric Power Annual/Monthly: 2014 Annual Capacity Factor used for all years (http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_07_a)

- **Natural gas CC power plants are typically intermediate or baseload plants.**
  - Today, NGCC is often the most economic generation; it will run when not down for maintenance
- **Natural gas CT power plants are less efficient than CCs and tend to run as Intermediate or Peaker plants**
- **Natural gas CC with CCS has not yet been built. It is expected to be a baseload unit. While it may have a derate due to the emissions capture at the end, we assumed the same capacity factor for NGCC and NGCC - CCS.**



The reference case does not include any carbon costs for conventional technologies. The LCOE of a CCS plant might be significantly reduced if it is able to sell the CO2 it has captured (e.g., and enhanced oil recovery operation may purchase CO2 from a CCS plant).

Fuel prices are based on the Annual Energy Outlook which only extend to 2040. Fuel prices post 2040 are held at the 2040 levels, which is why the LCOE shows a change after 2040.

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11. Coal Plants

Coal Power Plant – Technology Overview

Niagara Mohawk's Dunkirk steam station in New York
Photographer: David Parsons
Source: NREL photo library 06705.jpg and 06735.jpg

Electrical transmission lines in front of coal-fired power plant
Photographer: Warren Getz
Source: NREL photo library 10933.jpg

1. **Heat is created:** coal is pulverized, mixed with hot air and burnt in suspension
2. **Water turns to steam**: the heat turns purified water into steam and is piped to the turbine
3. **Steam turns the turbine:** the pressure of the steam pushes the turbine blade, turns the shaft in the generator and creates power
4. **Steam turned back into water**: cool water is drawn into a condenser where the steam turns back into water that can be used over again in the plant.

Adapted from: Duke Energy's website; http://www.duke-energy.com/about-energy/generating-electricity/coal-fired-how.asp

http://www.duke-energy.com/about-energy/generating-electricity/coal-fired-how.asp

Coal Generation CapEx Required for Commercial Operation

Coal Generation Technologies	
Coal-new	Advanced super critical with SO2 and NOx controls
Coal-IGCC	Integrated gasification combined cycle (IGCC)
Coal-CCS	IGCC with carbon capture & storage (CCS) options

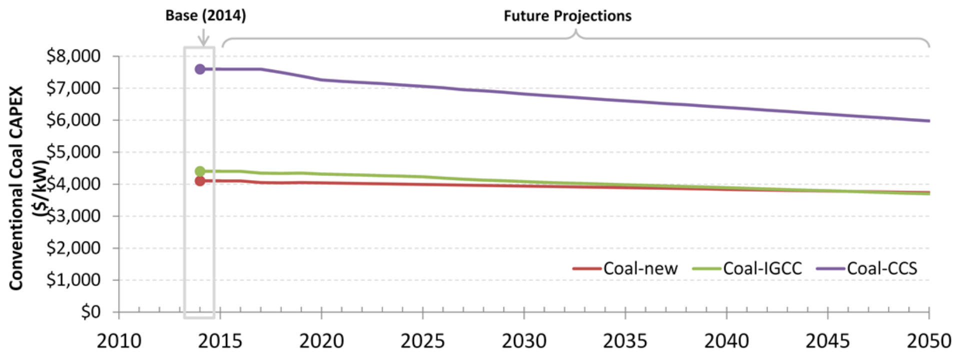
	Overnight capital cost ($/kW)	Construction financing factor	CAPEX ($/kW)
Coal-new	$3,535	1.161	$4,103
Coal-IGCC	$3,793	1.161	$4,403
Coal-CCS	$6,596	1.161	$7,657

OCC Source: Modified from U.S. DOE EIA – Annual Energy Outlook 2016
Capital cost includes overnight capital cost plus defined transmission cost, and removes a material price index.

- **CAPEX = ConFinFactor x OCC**
- **Fuel costs are just passed through to end user**
- **Fuel costs are also taken from EIA's AEO 2016**

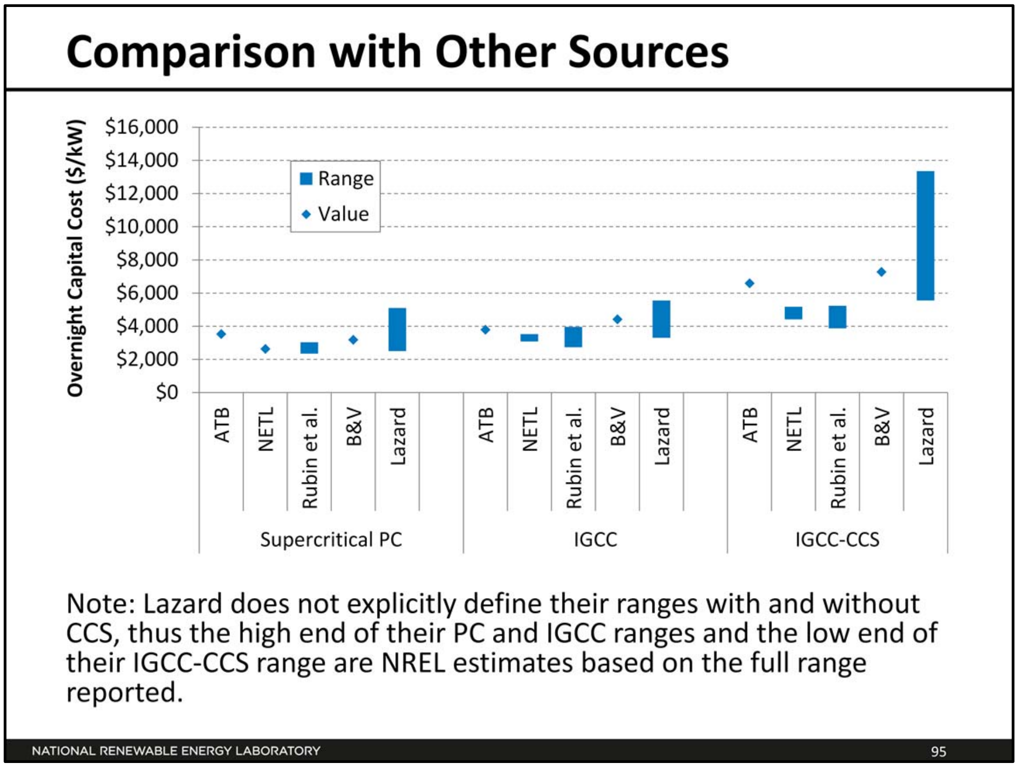
The Coal-CCS technology is the Coal-IGCC fitted with CCS and not a pulverized coal unit fitted with CCS.

Coal – CapEx Historic Trends, Current Estimates, and Future Projections



Source: Current estimates and future projections calculated from U.S. DOE EIA – Annual Energy Outlook 2016, modified.

- **A coal power plant is a well-known technology that already performs close to its optimum performance. As such, EIA expects that capital expenditures will incrementally improve over time, slightly more quickly than inflation.**
- **There are two exceptions. The U.S. Department of Energy's Fossil Energy office and the National Energy Technology Laboratory conduct research on reducing the costs and increasing the performance of :**
  - Integrated gasification combined cycle (where the coal is gasified, and then fed into a combined cycle turbine usually used to burn natural gas)
  - Coal in combination with carbon capture and storage (CCS). The CCS technology and costs are expected to reduce over time



Rubin et al. report "total capital requirement" which may not be exactly equivalent to the overnight capital costs assumed here

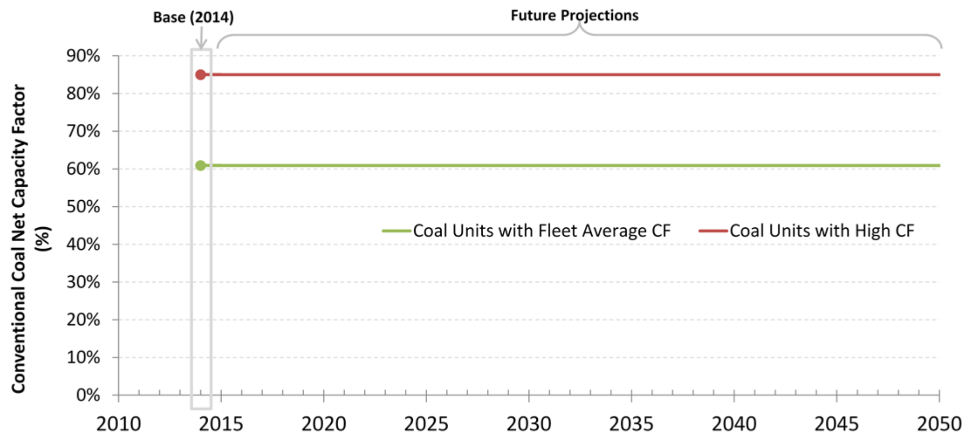
Sources:
Fout et al., Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3, (2015)
http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/Rev3Vol1aPC_NGCC_final.pdf
Fout et al., Cost and Performance Baseline for Fossil Energy Plants Volume 1b: Bituminous Coal (IGCC) to Electricity Revision 3, (2015)
http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/Rev-2b-Vol-1b-IGCC_final.pdf
Rubin et al., The cost of CO2 capture and storage, (2015)
http://www.sciencedirect.com/science/article/pii/S1750583615001814; preprint available at
http://www.cmu.edu/epp/iecm/rubin/PDF%20files/2015/Pages%20from%20Rubin_et_al_ThecostofCCS_IJGGC_2015.pdf
Black & Veatch, Cost and Performance Data for Power Generation Technologies, (2012)
http://bv.com/docs/reports-studies/nrel-cost-report.pdf%E2%80%8E
Lazard, Levelized Cost of Energy Analysis-Version 9.0, (2015)
https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf

Coal Operations and Maintenance Costs

- **Represents annual expenditures required to operate and maintain a coal plant over its technical lifetime including:**
  - Insurance, taxes, land lease payments, and other fixed costs
  - Present value, annualized large component replacement costs over technical life
  - Scheduled and unscheduled maintenance of coal power plants, transformers, etc. over technical lifetime
- **Market data for comparison is limited and generally inconsistent in range of costs covered, length of historic record**
- **O&M represents anticipated lifetime operation expenditures for new technology**

Cherokee Station coal-powered plant, Denver, Colorado
Photographer: Warren Getz
Source: NREL photo library 06360.jpg

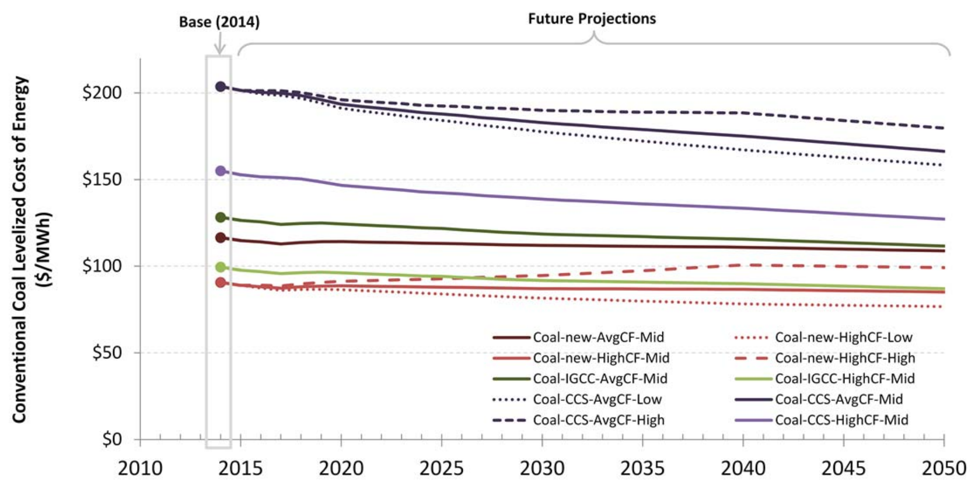
Coal – Capacity Factor:
Annual Average Energy Production over Lifetime



Source: U.S. DOE EIA – Electric Power Annual/Monthly: 2014 Annual Capacity Factor used for all years (http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_07_a)

- **Coal power plants are typically baseload plants, with steady capacity factors.**
- **Even though IGCC and Coal with CCS have experienced limited deployment in the United States, it is expected that their characteristics would be similar to new coal power plants.**

Coal Cost and Performance Projections



- **The LCOE of coal power plants are directly impacted by multiple coal fuel costs –high, mid, and low.**
- **The LCOE is also impacted by variations in the heat rate, O&M costs, and assumed capacity factor.**

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The reference case does not include any carbon costs for conventional technologies. The LCOE of a CCS plant might be significantly reduced if it is able to sell the CO2 it has captured (e.g., and enhanced oil recovery operation may purchase CO2 from a CCS plant).

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12. Nuclear Plants

Nuclear Power Plant – Technology Overview

Source: TVA Watts Bar Nuclear Power Plant | Photo courtesy of Tennessee Valley Authority
http://www.energy.gov/ne/nuclear-reactor-technologies

- Nuclear power contributed about 20% of U.S. electrical generation over the past two decades.
- Atoms have a large amount of energy holding their nuclei together. Isotopes of some elements can be split and will release part of their energy as heat. This splitting is called fission. The heat released in fission can be used to help generate electricity in power plants.
- During fission, U-235 atoms absorb loose neutrons. This causes U-235 to become unstable and split into two light atoms called fission products. The combined mass of the fission products is less than that of the original U-235. The reduction occurs because some of the matter changes into energy (namely heat). Two or three neutrons are released along with the heat. These neutrons may hit other atoms, causing more fission.
- A series of fissions is called a chain reaction. If enough uranium is brought together under the right conditions, a continuous chain reaction occurs. This is called a self-sustaining chain reaction, which creates a great deal of heat, which can be used to help generate electricity.
- Nuclear power plants generate electricity like any other steam-electric power plant. Water is heated, and steam from the boiling water turns turbines and generates electricity. The main difference is that heat from a self-sustaining chain reaction boils the water in a nuclear power plant (as opposed to burning fuels in fossil fuel plants).

http://energy.gov/ne/nuclear-reactor-technologies/light-water-reactor-sustainability-lwrs-program
http://energy.gov/ne/about-us/history
http://www.energy.gov/ne/nuclear-reactor-technologies

Nuclear Generation CapEx Required for Commercial Operation

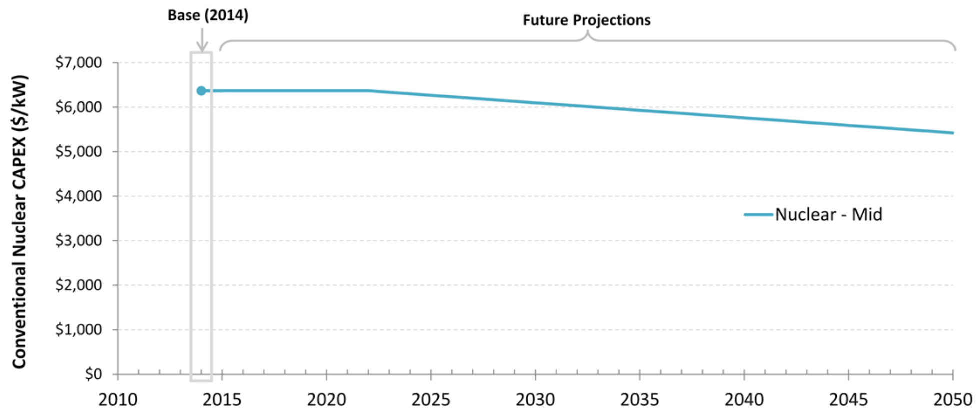
Nuclear Generation Technology	
Nuclear	Advanced nuclear power generation

	Overnight capital cost ($/kW)	Construction financing factor	CAPEX ($/kW)
Nuclear	$5,486	1.161	$6,369

OCC Source: Modified from U.S. DOE EIA – Annual Energy Outlook 2016
Capital cost includes overnight capital cost plus defined transmission cost, and removes a material price index.

- **CAPEX = ConFinFactor x OCC**
- **Costs are also taken from EIA's AEO 2016**

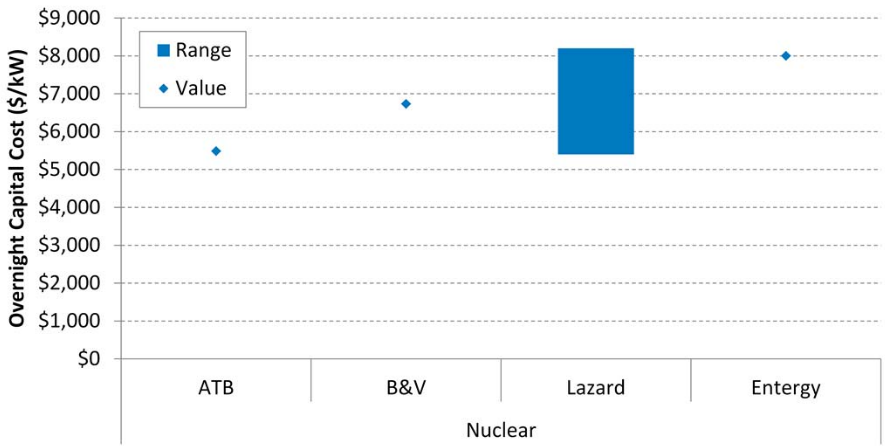
Nuclear – CapEx Historic Trends, Current Estimates, and Future Projections



Source: Current estimates and future projections calculated from U.S. DOE EIA – Annual Energy Outlook 2016, modified.

A nuclear power plant is a well-known technology that already performs close to its optimum performance. As such, EIA expects that capital expenditures will incrementally improve over time, somewhat more quickly than inflation.

Comparison with Other Sources



Note: ATB cost numbers are for a brown-field nuclear facility

Sources:
Black & Veatch, Cost and Performance Data for Power Generation Technologies, (2012) http://bv.com/docs/reports-studies/nrel-cost-report.pdf%E2%80%8E
Lazard, Levelized Cost of Energy Analysis-Version 9.0, (2015) https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf
Entergy, 2015 Integrated Resource Plan, (2015) http://entergy-arkansas.com/content/transition_plan/IRP_Materials_Compiled.pdf

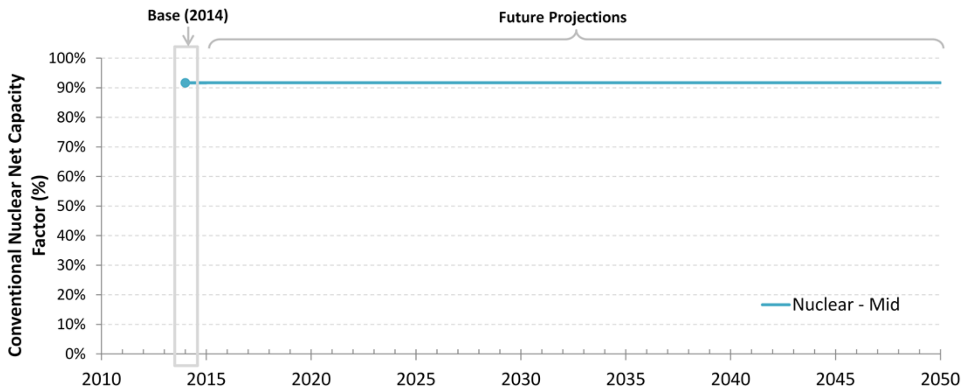
Nuclear Operations and Maintenance Costs

- **Represents annual expenditures required to operate and maintain a nuclear plant over its technical lifetime including:**
  - Insurance, taxes, land lease payments, and other fixed costs
  - Present value, annualized large component replacement costs over technical life
  - Scheduled and unscheduled maintenance of nuclear power plants, transformers, etc. over technical lifetime
  - Fuel rod replacement, storage, and handling
- **Market data for comparison is limited and generally inconsistent in range of costs covered, length of historic record**
- **O&M represents anticipated lifetime operation expenditures for new technology**

Photo credit: Idaho National Laboratory
Nuclear operating crews run simulations with the HSSL research team
Taken on November 7, 2012

https://www.flickr.com/photos/inl/9420873449/

Nuclear – Capacity Factor:
Annual Average Energy Production over Lifetime

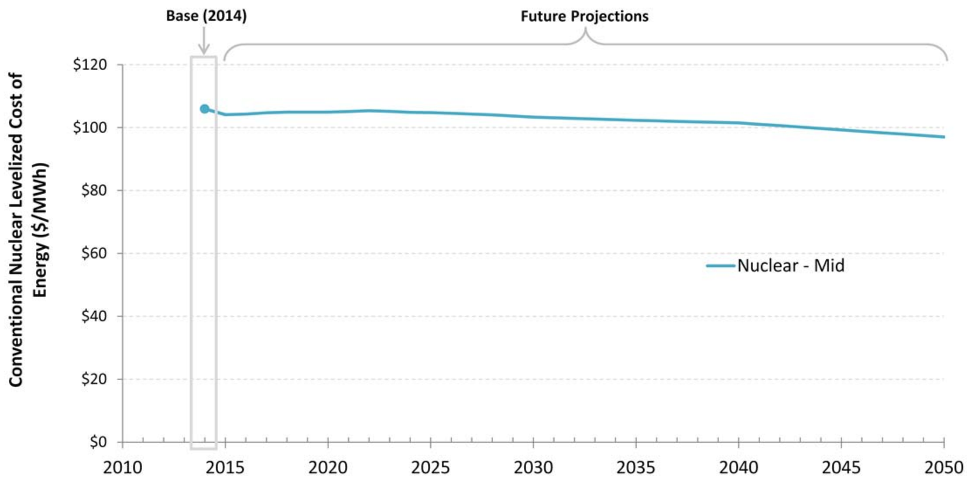


Source: U.S. DOE EIA – Electric Power Annual/Monthly: 2014 Annual Capacity Factor used for all years (http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_07_b)

- **Nuclear power plants are typically baseload plants, with steady capacity factors.**
- **Nuclear power plants need to change out their uranium fuel rods about every 24 months. After 18-36 months, the used fuel is removed from the reactor. The average fueling outage duration in 2013 was 41 days; from 1990-1997, the refueling days ranged from 66-106, so improvements have helped capacity factors.**
- **According to the Nuclear Energy Institute, the average capacity factors for nuclear power plants was 90.9% in 2013. In fact, since 2007, the capacity factors have ranged between 86.4% - 91.8%.**

http://www.world-nuclear.org/info/Nuclear-Fuel-Cycle/Introduction/Nuclear-Fuel-Cycle-Overview/
http://www.nei.org/Knowledge-Center/Nuclear-Statistics/US-Nuclear-Power-Plants/US-Nuclear-Refueling-Outage-Days
http://www.nei.org/Knowledge-Center/Nuclear-Statistics/US-Nuclear-Power-Plants
http://www.nei.org/Knowledge-Center/Nuclear-Statistics/US-Nuclear-Power-Plants/US-Nuclear-Capacity-Factors

Nuclear Cost and Performance Projections



- **The LCOE of nuclear power plants are directly impacted by the cost of uranium, variations in the heat rate, and O&M costs.**
- **The downtime from refueling nuclear power plants is another big factor.**

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13. Biomass Plants

Biomass Power Plant Technology Overview

NIPSCO generating station
Photographer: Photographer: Kevin Craig
Source: NREL photo library, 08928.jpg

McNeil Generating Station in Burlington, VT operates on wood chips
Photographer: David Parsons
Source: NREL photo library, 06905.jpg

1. **Heat is created:** biomass (sometimes co-fired with coal) is pulverized, mixed with hot air and burnt in suspension
2. **Water turns to steam**: the heat turns purified water into steam; is piped to the turbine
3. **Steam turns the turbine:** the pressure of the steam pushes the turbine blade, turns the shaft in the generator and creates power
4. **Steam turned back into water**: cool water is drawn into a condenser where the steam turns back into water that can be used over again in the plant.

Adapted from: Duke Energy's website

Biomass Generation CapEx Required for Commercial Operation

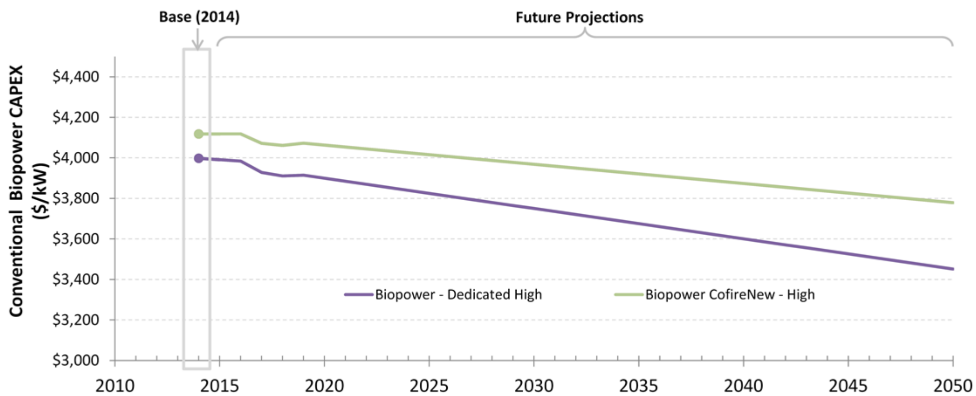
Biomass Generation Technologies	
Dedicated	Dedicated biomass plant
CofireOld	Pulverized coal with sulfur dioxide (SO2) scrubbers and biomass co-firing
CofireNew	Advanced super critical coal with SO2 & NOx controls and biomass co-firing

	Overnight capital cost ($/kW)	Construction financing factor	CAPEX ($/kW)
Dedicated	$3,718	1.075	$3,998
CofireOld	$3,829	1.075	$4,118
CofireNew	$3,829	1.075	$4,118

OCC Source: Modified from U.S. DOE EIA – Annual Energy Outlook 2016
Capital cost includes overnight capital cost plus defined transmission cost, and removes a material price index.

- **CAPEX = ConFinFactor x OCC**
- **Fuel costs are just passed through to end user**
- **Fuel costs are also taken from EIA's AEO 2016**

Biomass – CapEx Historic Trends, Current Estimates, and Future Projections

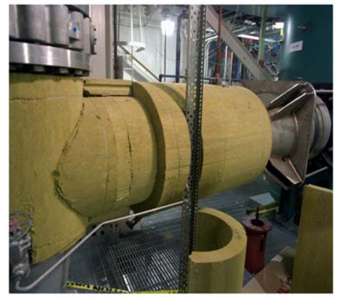


Source: Current estimates and future projections calculated from U.S. DOE EIA – Annual Energy Outlook 2016, modified.

- A biomass power plant is a well-known technology that performs close to its optimum performance. As such, EIA expects that capital expenditures will incrementally improve over time, slightly more quickly than inflation.
- The exception is new biomass cofiring, which is expected to have the costs reduce a bit more than existing cofiring project technologies.

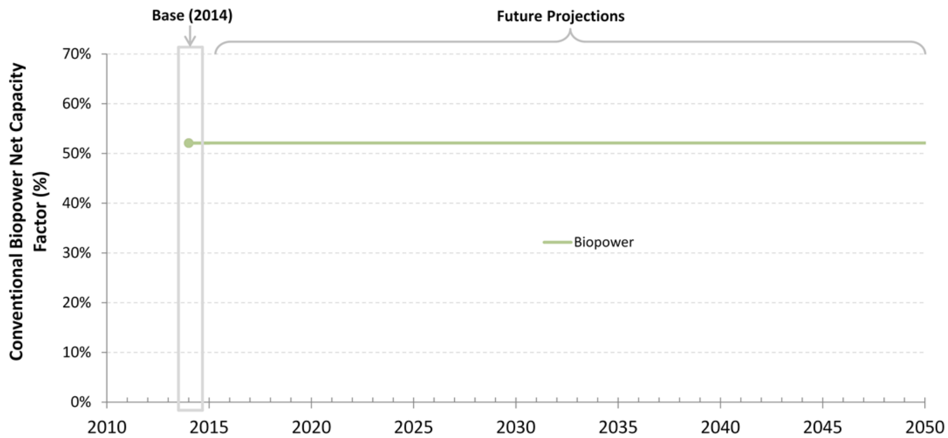
Biomass Operations and Maintenance Costs

- **Represents annual expenditures required to operate and maintain a biomass plant over its technical lifetime including:**
  - Insurance, taxes, land lease payments, and other fixed costs
  - Present value, annualized large component replacement costs over technical life
  - Scheduled and unscheduled maintenance of biomass power plants, transformers, etc. over technical lifetime
- **Market data for comparison is limited and generally inconsistent in range of costs covered, length of historic record**
- **O&M represents anticipated lifetime operation expenditures for new technology**



McNeil Generating Station at Burlington, VT – a biomass gasifier which operates on wood chips.
Photographer: Warren Gretz
Source: NREL photo library, 06382.jpg

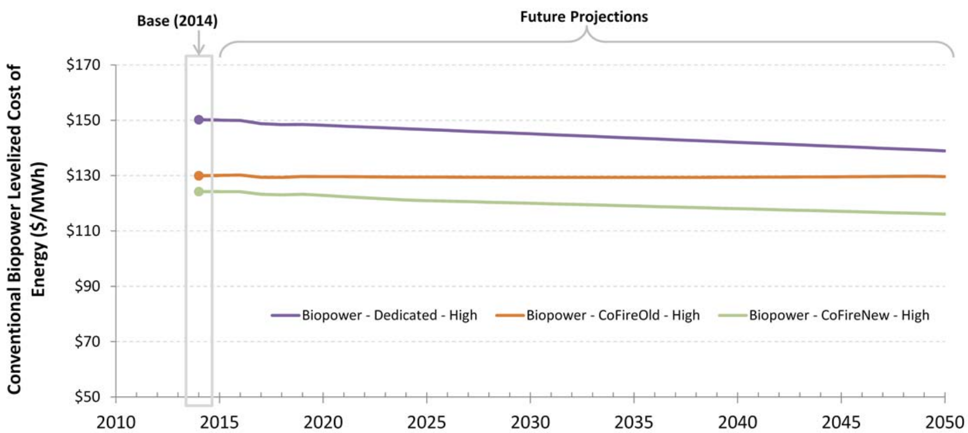
Biomass – Capacity Factor:
Annual Average Energy Production over Lifetime



Source: U.S. DOE EIA – Electric Power Annual/Monthly: 2014 Annual Capacity Factor used for all years (http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_07_b)

- **Biomass power plants are typically baseload plants, with steady capacity factors.**
- **Biopower capacity factors are influenced by technology and feedstock supply, expected downtime, and energy losses.**

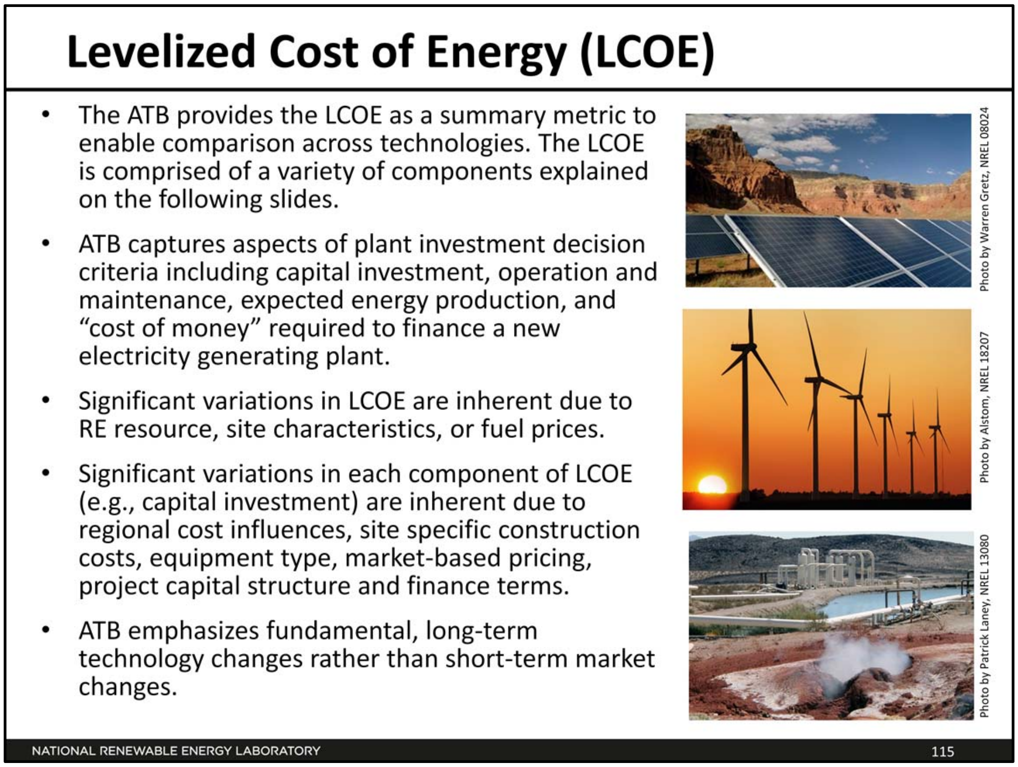
Biomass Cost and Performance Projections



- **The LCOE of biomass power plants are directly impacted by the differences in CAPEX (installed capacity costs), as well as heat rate differences.**
- **Regional variations will ultimately impact biomass feedstock costs, but those are not included in this analysis.**

The reference case does not include any carbon costs for conventional technologies.

14. Summary of Technologies



- LCOE **IS NOT** the only metric used to compare electricity generation technology options. **FOR EXAMPLE,** additional system considerations such as planning and operating reserves, output correlation with nearby plants, and other aspects are included in ReEDS and depend on the overall scenario constraints.
- Standard Scenarios results produced with the ReEDS model do include transmission infrastructure expansion and electric system operation costs.
- This framework should be suitable to inform input assumptions for capacity expansion models such as the National Energy Modeling System (NEMS), MARKAL/TIMES, and Integrated Planning Model (IPM).
- This framework could be adapted to provide similar comparisons of inputs to other model-based studies such as those using System Advisor Model (SAM), Buildings Industry Transportation Electricity Scenarios (BITES), Cost of Renewable Energy Spreadsheet Tool (CREST), etc.
- The LCOE values presented here represent busbar costs at the plant gate; transmission spur lines and electric system operation costs are not included.

LCOE Equation

$$LCOE = \frac{FCR \ast CAPEX + FOM}{CF \times 8760} + VOM + FUEL$$

(terms defined here and on following pages)

- **Assumptions common to all technologies**
  - Generation projects receive similar terms from lenders and equity investors over a 20-year project economic life (WACC = 8.1% nominal/5.4% real)
  - Federal/state blended tax rate does not vary; depreciation schedules vary by technology based on Tax Code
- **Technology-specific assumptions detailed in each subsequent section**
  - Capital Expenditures (CAPEX) represented by total expenditure per kW plant capacity required to achieve commercial operation in a given year
  - O&M represented by average annual fixed (FOM) and variable costs (VOM) over technical life of project
  - Fuel costs applied to some technologies
  - Capacity Factor (CF) used to represent average annual energy production per kW of plant capacity over technical life of project

- Variables are defined on Financial Definitions tab in ATB spreadsheet.
- Levelized Cost of Energy (LCOE) selected to represent typical electricity generation cost elements in common framework including project finance (FCR), capital expenditures (CAPEX), fixed and variable operation and maintenance costs (FOM and VOM), and annual energy production/kW plant capacity based on capacity factor (CF) and hours in a year (8760), and fuel costs.
- ATB spreadsheet and accompanying documentation illustrate range of LCOE for electricity generation technologies. Renewable generation technology cost range generally dictated by natural long-term renewable resource characteristics. Fuel-based technology cost range generally dictated by assumed range of future fuel cost.
- Project finance is represented using common assumptions for all technologies in order to focus differences on technical aspect. Depreciation is technology-specific based on IRS tax code. Future ATB modifications to capture actual financing differences between technologies is under consideration.
- LCOE values in the ATB do not include any investment tax credit or production tax credit.

Summary of Project Finance Terms

$$FCR = CRF \ * ProFinFactor$$

- **Fixed Charge Rate (FCR):** Amount of revenue per dollar of investment required that must be collected annually from customers to pay the carrying charges on that investment.
- **Capital Recovery Factor (CRF):** The ratio of a constant annuity to the present value of receiving that annuity for a given length of time (10.2% nominal / 8.3% real).
- **Project Finance Factor (ProFinFactor):** Technology-specific financial multiplier to account for any applicable differences in depreciation schedule.

- For long-term scenarios (through 2050) it is assumed that all electricity generation projects receive similar terms from lenders and equity investors. Although perceived level of risk across generation technologies may vary somewhat today, over the period of analysis, it is assumed that all technology options reach a common level of maturity and that there are no systematic differences in risk perception from the finance community. This assumption also focuses the scenario results on changes in the technology cost and performance.
- Future ATB modifications may include the ability to capture actual financing differences between technologies, in the short-term.
- See Excel spreadsheet for equations, variable definitions, and parameters.

Summary of Capital Expenditure (CAPEX) Terms

$$CAPEX = ConFinFactor * (OCC \ * RegCapMult + GCC)$$

- **Construction Finance Factor (ConFinFactor):** Portion of capital expenditure associated with construction period financing. ConFinFactor is a function of construction period duration, interest rate, and expenditure schedule.
- **Overnight Capital Cost (OCC):** Capital expenditures excluding construction period financing. Includes onsite electrical equipment (e.g., switchyard), a nominal-distance spur line (<1 mi), and necessary upgrades at a transmission substation.
- **Capital Regional Multiplier (CapRegMult):** Capital cost multipliers to account for regional variations that affect plant costs, e.g. labor rates. ATB does not represent these regional impacts (CapRegMult = 0), but Standard Scenarios outputs do include regional impacts for some technologies.
- **Grid Connection Costs (GCC):** Spur line costs from the plant gate to the high voltage transmission network based on geographic distance. ATB does not represent distance based grid connections costs (GCC=0) with the exception of offshore wind plants. Standard Scenarios outputs do include site-specific grid connection costs for wind (both land-based and offshore) and solar-CSP plants.

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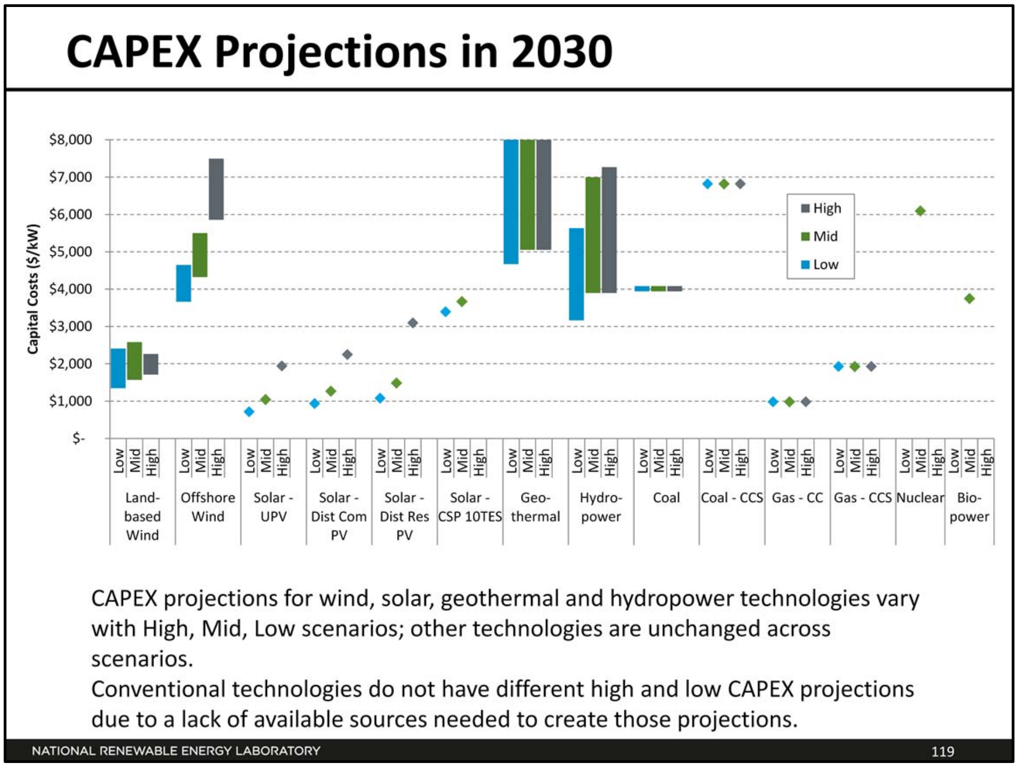
- ATB CAPEX represents typical plant costs and does not represent regional variants associated with labor rates, material costs, etc. or geographically determined spur line costs. These effects can be represented in the ATB spreadsheet, however, and are represented in Standard Scenario outputs for some technologies.
- Overnight capital costs are based on the plant envelope defined by Beamon and Leff (2013) to include all capital expenditures with the exception of construction-period financing. OCC includes onsite electrical equipment (e.g., switchyard), a nominal-distance spur line (<1 mi), and necessary upgrades at a transmission substation.
- Grid Connection Costs represent distance-based costs of spur lines for utility PV, land-based wind, and offshore wind plant export cable costs and construction-period transit costs.
- The ATB technology CAPEX estimates represent general plant capital expenditures and exclude geography specific costs associated with distance to high-voltage transmission line connections or regional cost impacts, e.g., labor rates. These geography specific parameters are applied at various spatial levels within the ReEDS model depending upon the technology. All Standard Scenarios model results include these geography specific parameters that are not represented by the ATB estimates.
- Subsequent notes pages identify differences between what is presented in the ATB slides and additional information that is included in ReEDS Standard Scenarios outputs.

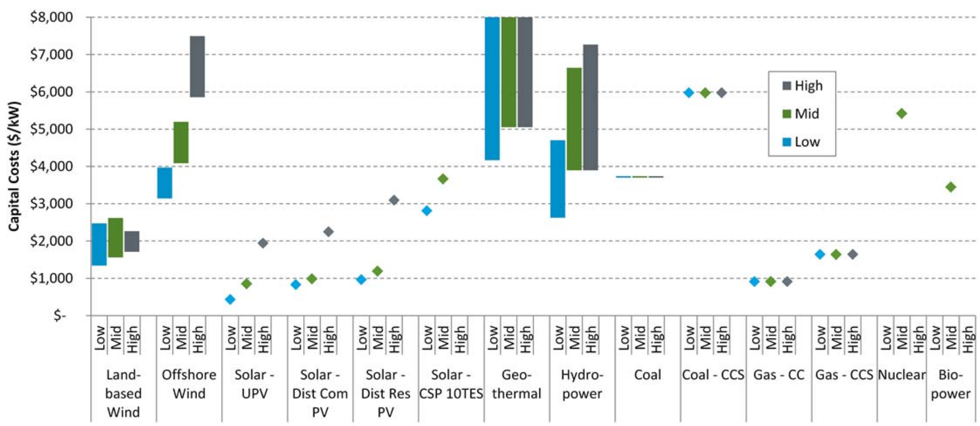
References:

Beamon, A.; Leff. M. (2013). EOP III Task 1606, Subtask 3 – Review of Power Plant Cost and Performance Assumptions for NEMS. Prepared by SAIC Energy, Environment & Infrastructure, LLC for the Energy Information Administration, Office of Energy Analysis. http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf



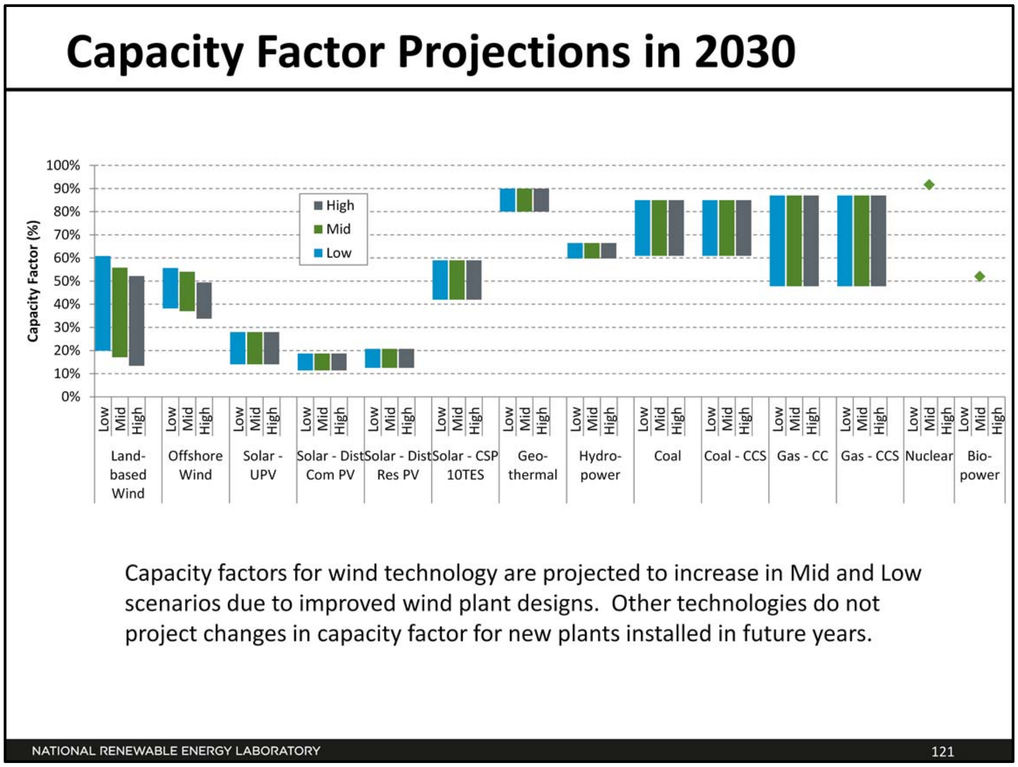
Some values are ranges because of capital costs that are site specific. For example, a low wind speed site may utilize a taller turbine with a higher capital cost compared to a high wind speed site.

CAPEX Projections in 2050

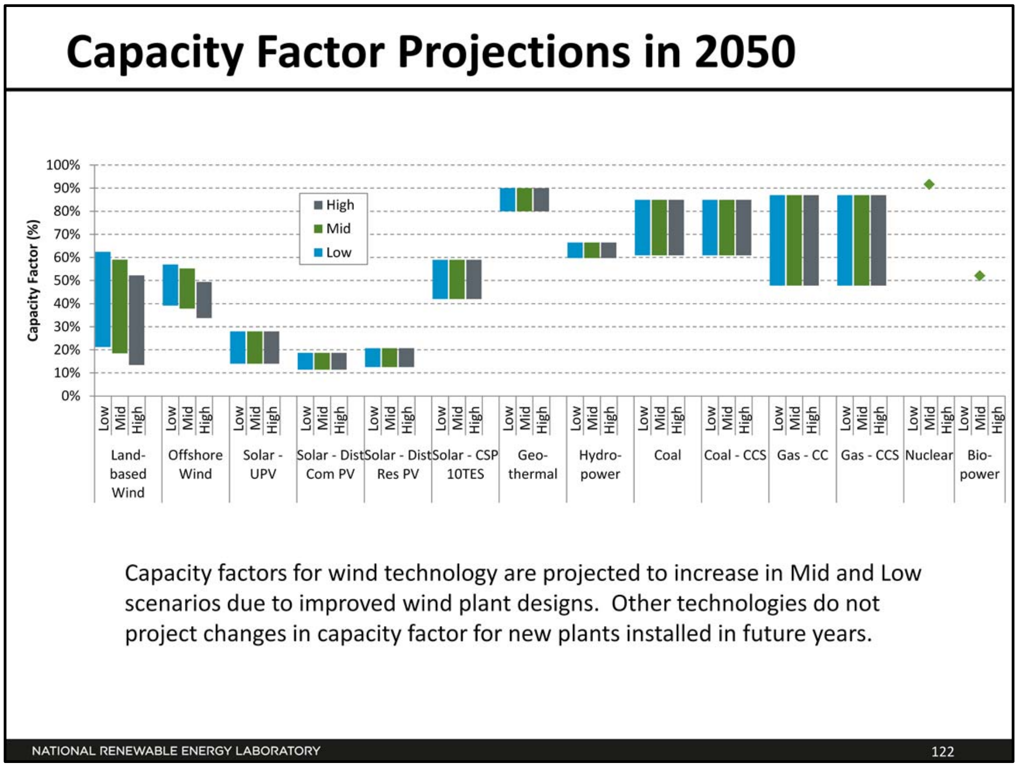


CAPEX projections for wind, solar, geothermal and hydropower technologies vary with High, Mid, Low scenarios; other technologies are unchanged across scenarios.
Conventional technologies do not have different high and low CAPEX projections due to a lack of available sources needed to create those projections.

Some values are ranges because of capital costs that are site specific. For example, a low wind speed site may utilize a taller turbine with a higher capital cost compared to a high wind speed site.

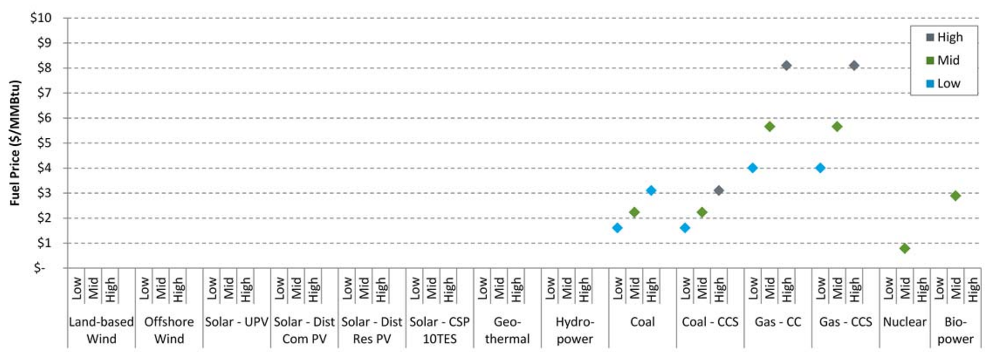


- Note that the range of capacity factors for conventional technologies represent the historical average across the entire U.S. fleet, by fuel type and generator type (lower value) and a value consistent with historic investment decision (upper value). Individual capacity factors for each plant's actual operation will vary significantly.
- Capacity factors for RE technologies represent expected annual average annual energy production for a new plant installed in a given year over the lifetime of that plant. Inter-annual variation in energy production is not represented.
- UPV capacity factors are for one-axis tracking systems and are in terms of DC capacity to AC output.



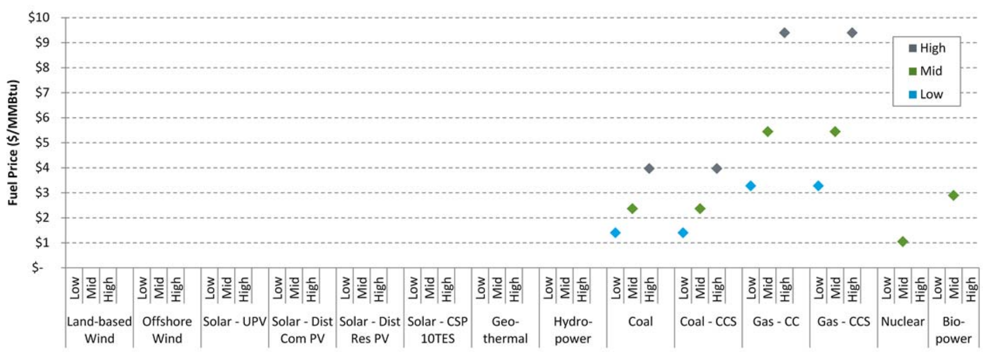
- Note that the range of capacity factors for conventional technologies represent the historical average across the entire U.S. fleet, by fuel type and generator type (lower value) and a value consistent with historic investment decision (upper value). Individual capacity factors for each plant's actual operation will vary significantly.
- Capacity factors for RE technologies represent expected annual average annual energy production for a new plant installed in a given year over the lifetime of that plant. Inter-annual variation in energy production is not represented.
- UPV capacity factors are for one-axis tracking systems and are in terms of DC capacity to AC output.

Fuel Price Projections in 2030



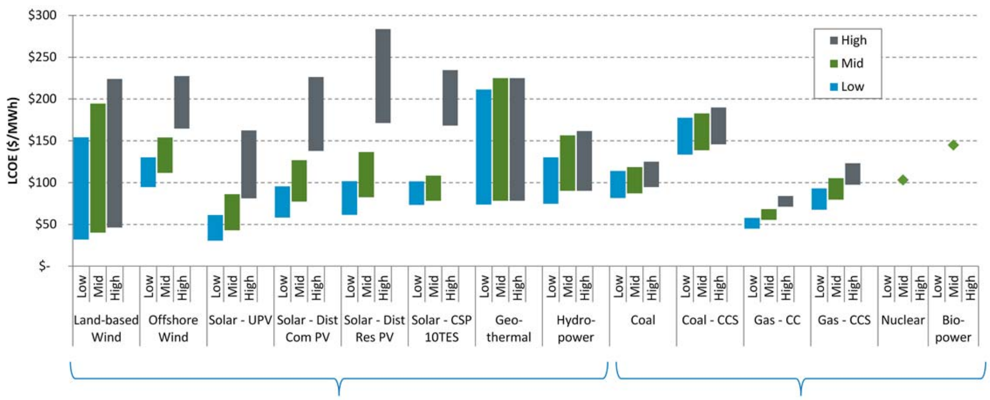
Fossil fuel prices are from the Annual Energy Outlook 2016. Biopower fuel prices are from the Billion Ton Update Study. More details are provided in the technology descriptions.

Fuel Price Projections in 2050



Fossil fuel prices are from the Annual Energy Outlook 2016. Biopower fuel prices are from the Billion Ton Update Study. More details are provided in the technology descriptions.

LCOE Projections in 2030

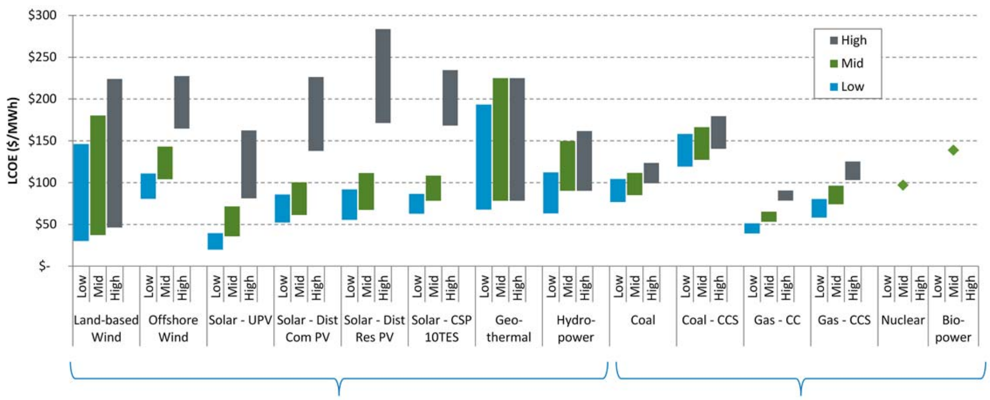


Cost and performance improvements for wind, solar, geothermal, and hydropower technologies result in lower magnitude LCOE and tighter range across resources.

Cost reductions for conventional technologies are associated with lower fuel costs.

LCOE projections do not include any investment tax credit or production tax credit.

LCOE Projections in 2050



Cost and performance improvements for wind, solar, geothermal, and hydropower technologies result in lower magnitude LCOE and tighter range across resources.

Cost reductions for conventional technologies are associated with lower fuel costs.

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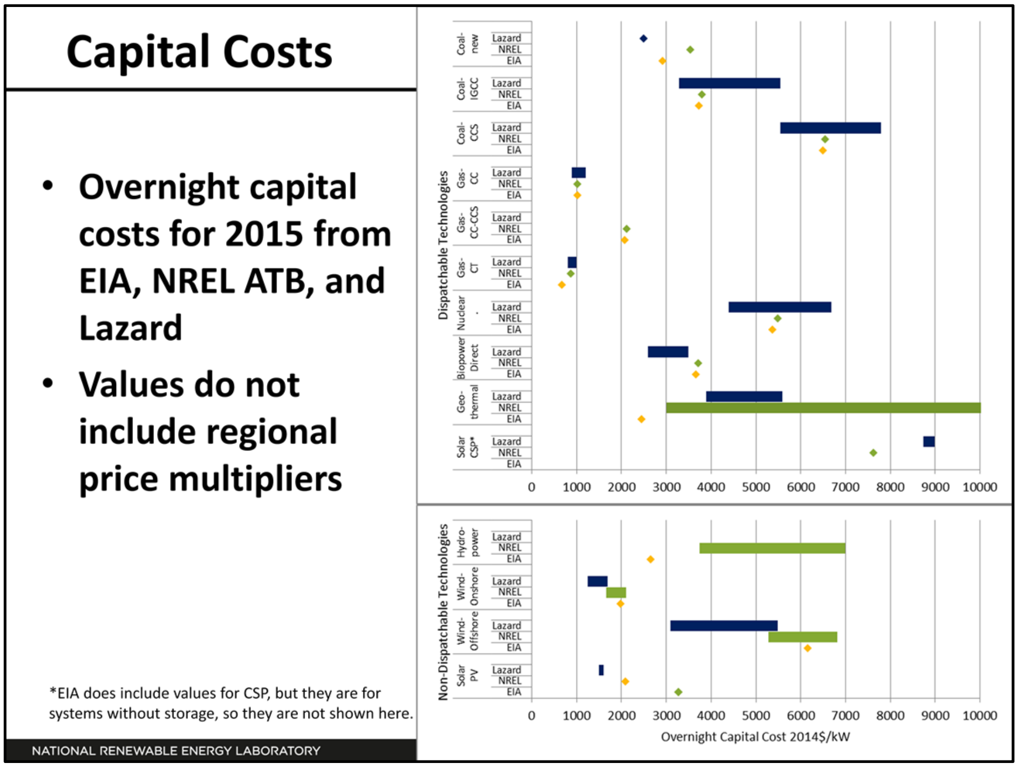
LCOE projections do not include any investment tax credit or production tax credit.

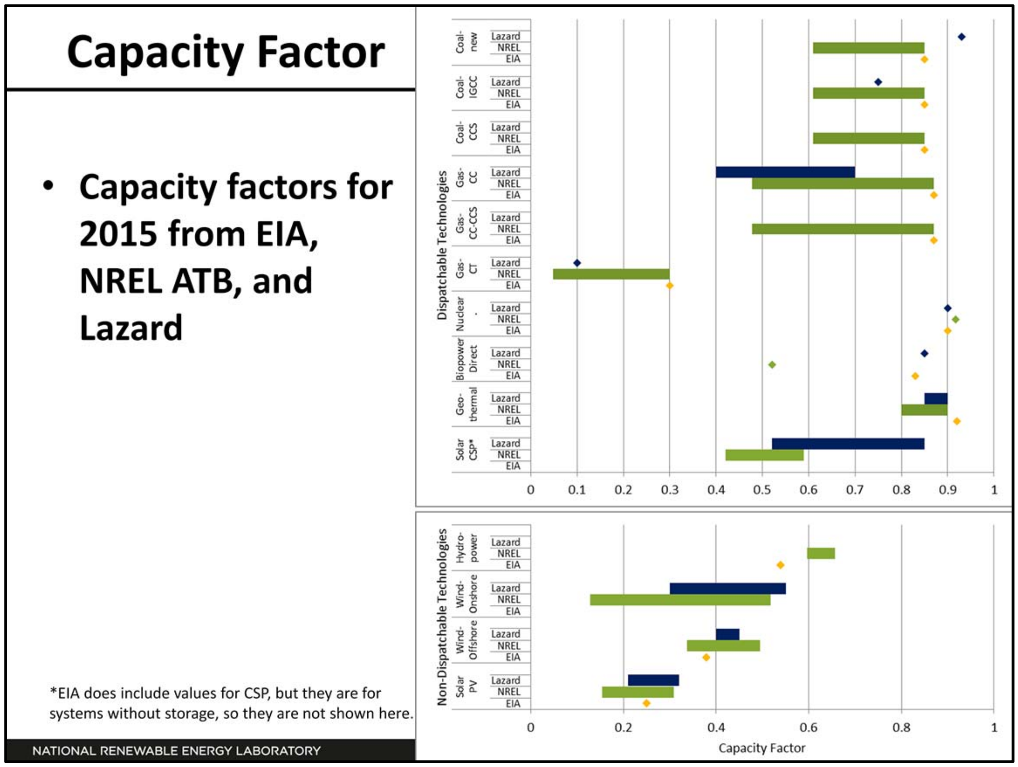
15. Comparison of Current Values with Other Sources



Values are for systems that come online in 2015. Values are overnight capital costs.

Hydropower is included in the non-dispatchable portion because it is assumed that *new* hydropower plants will likely have less dispatchability than existing hydropower units.

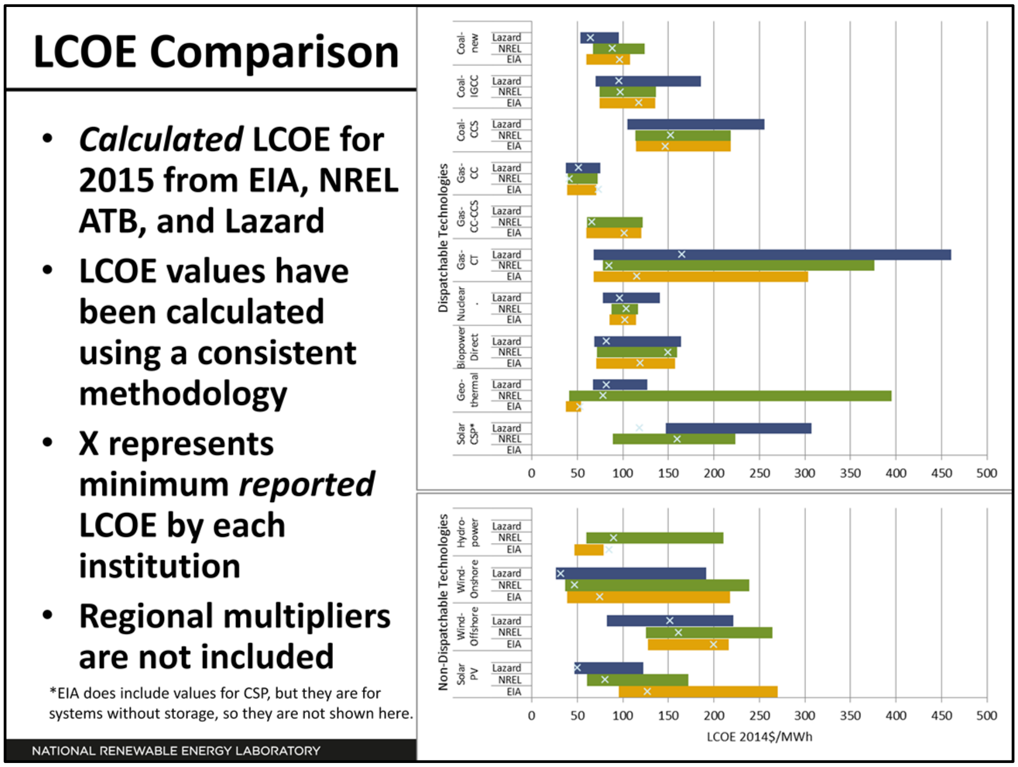
Sources:
Lazard: Levelized Cost of Energy Analysis 9.0 (https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf)
NREL: Annual Technology Baseline 2015 (http://www.nrel.gov/analysis/data_tech_baseline.html)
EIA: Annual Energy Outlook 2015 (http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf, see especially table 8.2 at https://www.eia.gov/forecasts/aeo/assumptions/pdf/table_8.2.pdf)



Values are for systems that come online in 2015. Capacity factors are annual values.

Hydropower is included in the non-dispatchable portion because it is assumed that *new* hydropower plants will likely have less dispatchability than existing hydropower units.

Sources:
Lazard: Levelized Cost of Energy Analysis 9.0 (https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf)
NREL: Annual Technology Baseline 2015 (http://www.nrel.gov/analysis/data_tech_baseline.html)
EIA: Annual Energy Outlook 2015 (http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf, see especially table 8.2 at https://www.eia.gov/forecasts/aeo/assumptions/pdf/table_8.2.pdf)



Values are for systems that come online in 2015. The minimum reported LCOE value is shown by the "x" in the figure.

EIA uses a single value for plants that come online in 2020.

The range of LCOE is a calculated range rather than a reported range. Because of differences in financing assumptions, construction schedules, capacity factors, fuel prices, etc., directly comparing the reported LCOE values is not very meaningful. The calculated ranges shown here are calculated using the same methodology and assumptions in order to avoid differences due to financing, etc. Under this methodology we used the capital costs, O&M costs, and heat rates directly from the three sources. However, for the other assumptions, we developed two sets of assumptions: one that would produce the maximum LCOE and one that would produce the minimum LCOE. For example, the minimum LCOE assumptions used lower fuel costs, lower financing costs, high capacity factors, etc. The capital and O&M costs and heat rates from the three sources were used to calculate the minimum and maximum LCOE using the two sets of assumptions. In this way the calculated LCOE ranges directly reflect differences in capital costs, O&M costs, and heat rates, but not other differences such as financing, etc.

Hydropower is included in the non-dispatchable portion because it is assumed that *new* hydropower plants will likely have less dispatchability than existing hydropower units.

Sources:
Lazard: Levelized Cost of Energy Analysis 9.0 (https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf)
NREL: Annual Technology Baseline 2015 (http://www.nrel.gov/analysis/data_tech_baseline.html)
EIA: Annual Energy Outlook 2015 (http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf, see especially table 8.2 at https://www.eia.gov/forecasts/aeo/assumptions/pdf/table_8.2.pdf); For reported LCOE values see https://www.eia.gov/forecasts/aeo/electricity_generation.cfm

16. Appendix

Converting ATB PV Costs

- **ATB PV costs are in $\$/W_{DC}$ with a 1.1 inverter loading ratio**
- **In this example we convert PV costs to $\$/W_{AC}$ with a 1.25 inverter loading ratio**
- **To convert between them, we need to account for the extra panels used with the higher inverter loading ratio:**

$$\$/W_{AC} = \left(\$/W_{DC}\right)\left(\text{ILR}\right) + \left(\$/W_{\text{Panel}_{DC}}\right)\left(\Delta\text{ILR}\right)$$

- **Using \$0.65/W for the panel costs we get:**

$$\$/W_{AC} = \left(\$1.90/W_{DC}\right)\left(1.1\right) + \left(\$0.65/W_{\text{Panel}_{DC}}\right)\left(1.25-1.1\right)$$

$$= \$2.20/W_{AC}$$

Source for panel costs: Fu et al., Economic competitiveness of U.S. utility-scale photovoltaics systems in 2015: Regional cost modeling of installed cost (\$/W) and LCOE (\$/kWh). Photovolt. Spec. Conf. PVSC 2015 IEEE 42nd, 2015, p. 1–11.

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17. Changes from 2015 ATB to 2016 ATB

Basic Approach Remains the Same – Consistency Across Technologies Improved

- **Base Year (current) cost and performance estimates from published, regularly updated sources or methods. If estimates are not based directly on market data, then they are compared with market observations as possible.**
- **Projections for future renewable energy cost and performance based on published literature such that:**
  - High = current cost
  - Mid = median value of literature or mid-level projection from published US-focus technology analysis (e.g., Hydropower Vision)
  - Low = Low = low bound of literature or low-level projections from published US-focus technology analysis
  - Renewable energy exceptions include:
    - Geothermal: Vision study currently underway and will inform 2017 ATB
    - Solar CSP: Direct comparison not yet feasible due to differences in storage, field sizes, turbine technologies, etc.

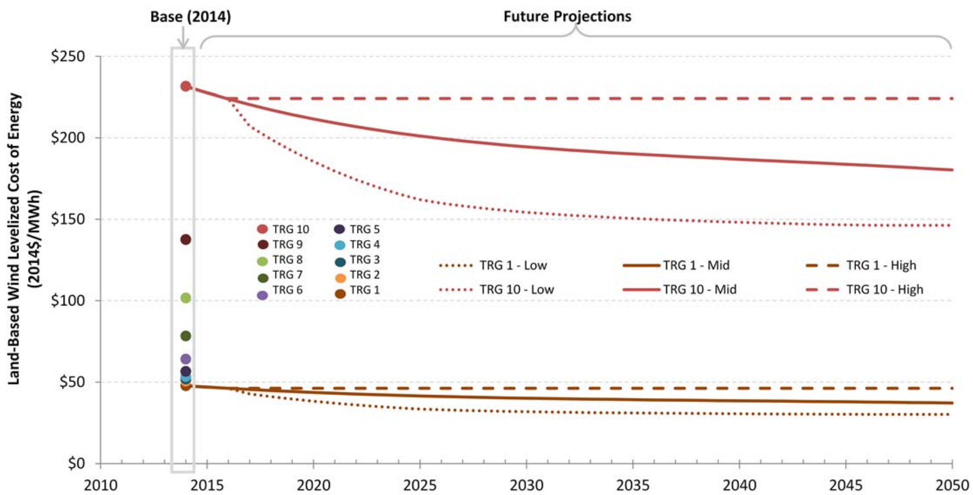
Summary of Changes from 2015 ATB to 2016 ATB

- **Changes to all technologies**
  - Updated base year from 2013 to 2014
  - Updated dollar year from 2013$ to 2014$
  - Updated historical data to include data reported in 2014
  - Changed debt-to-equity ratio to 60/40 based on a literature review (see Mai et al., NREL/PR-6A20-65014, 2015)
  - Added comparison of ATB inputs and calculated LCOE against EIA and Lazard reported values

Dollar year update is based on the consumer price index, which showed 1.6% inflation from 2013 to 2014.

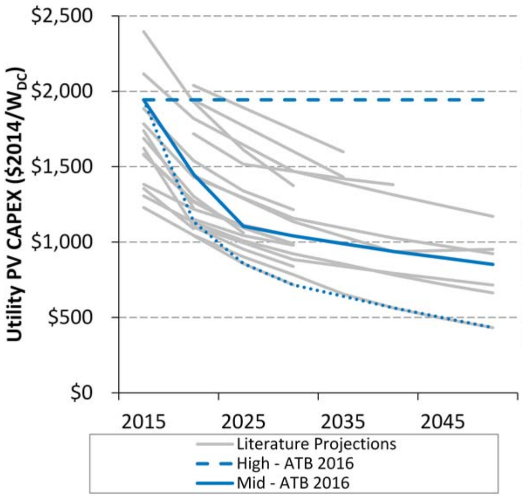
Land-based & Offshore Wind

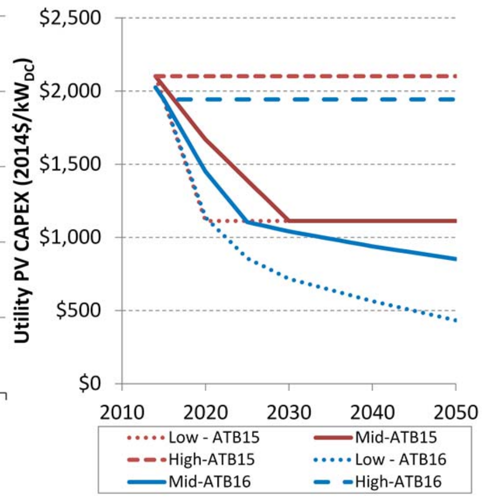
- **Base year and projections still based on Wind Vision, but TRGs expanded from 5 to 10**



Utility PV

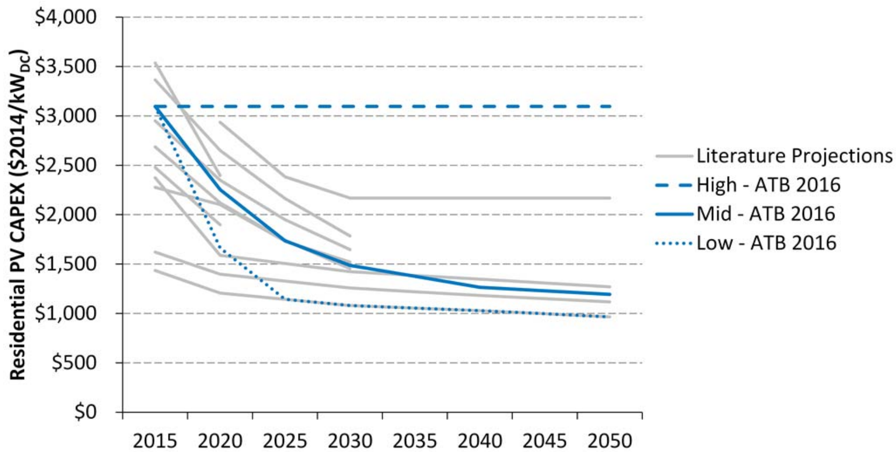
- 2014 & 2015 costs updated based on Feldman et al. NREL/PR-6A20-64898, 2015
- 2016 ATB UPV projections are based on literature trajectories (Low = minimum; Mid = median) rather than SunShot Report trajectories used in ATB 2015





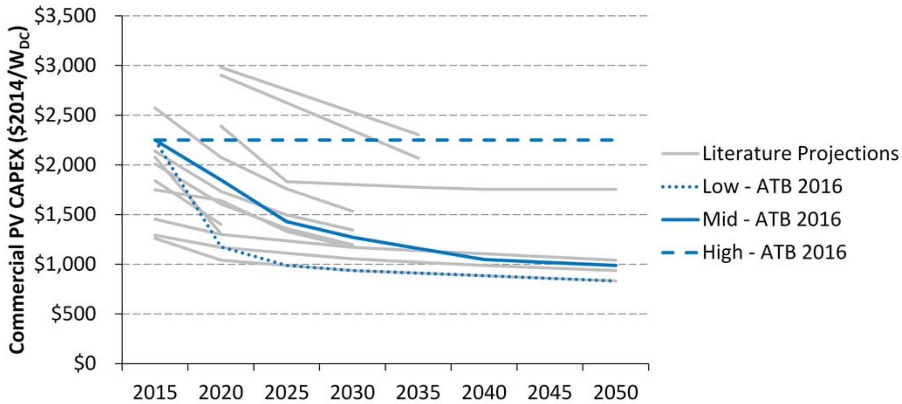
Residential PV

- **Residential PV trajectories based on same methodology as UPV**



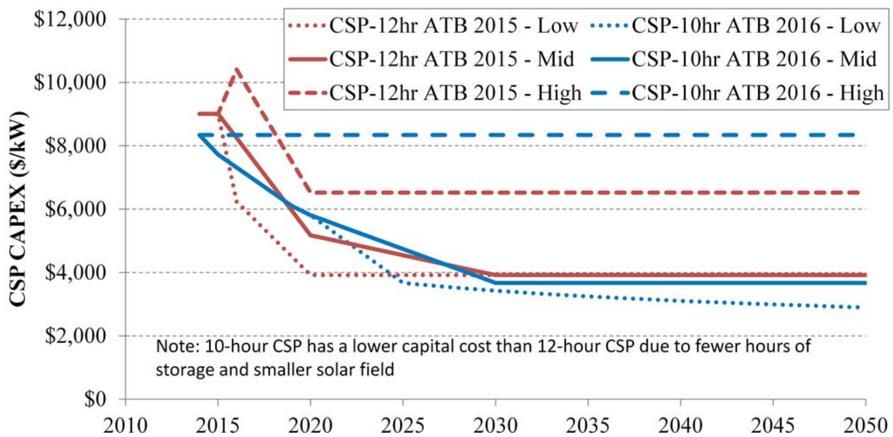
Commercial PV

- **Commercial PV trajectories based on same methodology as UPV**



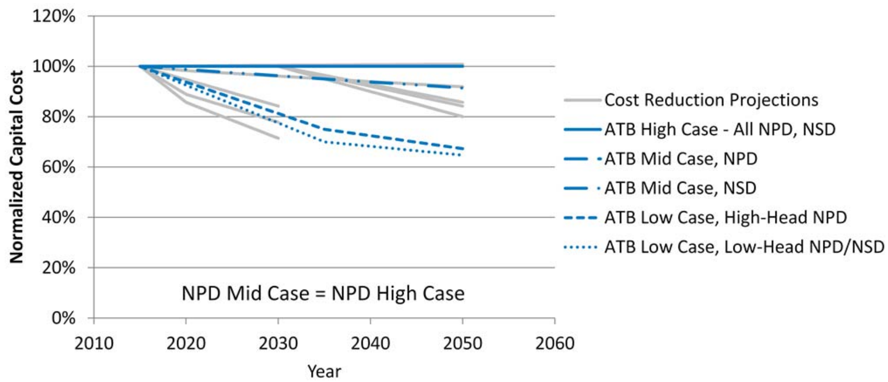
Concentrating Solar Power (CSP)

- Default representation now uses 10 hours of storage and 2.4 solar multiple (2015 ATB used 12 and 6 hours with 2.5 and 2, respectively, for solar multiples)
- 2020 point on mid and low cost scenarios is based on “On the Path to SunShot”
- Mid case still hits SunShot target in 2030
- Low case now hits SunShot target in 2025 instead of 2020, and includes learning post-2025



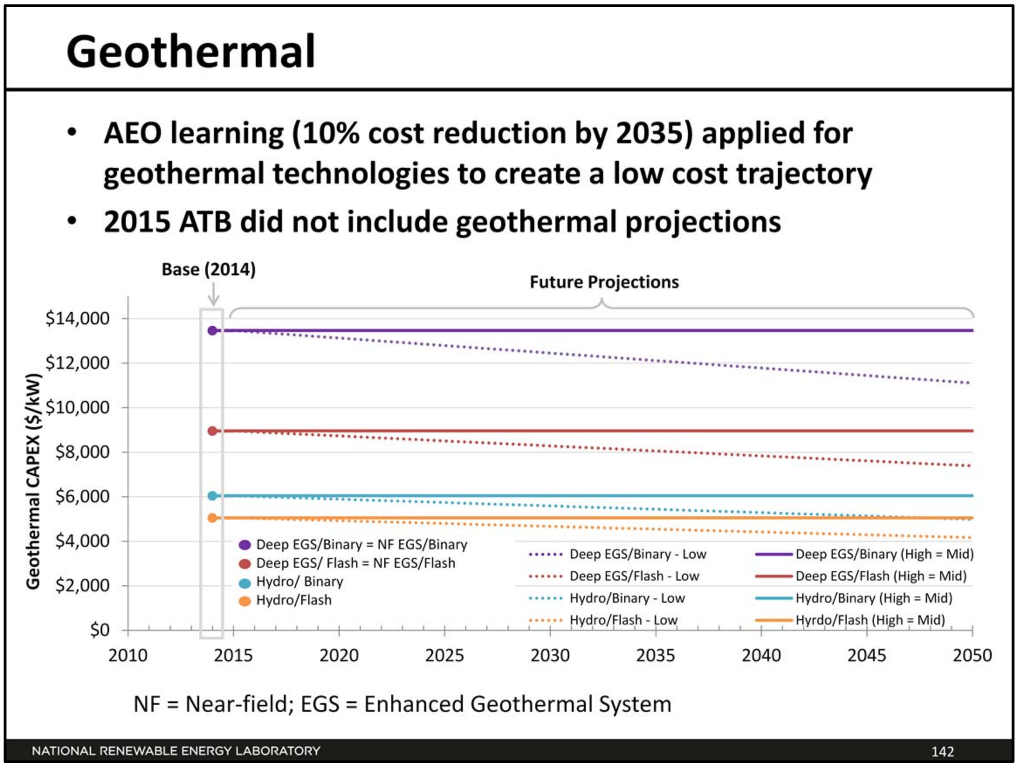
Hydropower

- **Projections based on industry input and comparison with published literature with focus on US resources (e.g., non-powered dams, new stream-reach development) from 2016 Hydropower Vision report.**
- **2015 ATB did not include hydropower projections**



Last year's ATB only included base year values.

Hydropower Vision report includes more detailed, bottom-up, component cost bases for projections of future cost. Draft report currently in external review and publication planned for July 2016.



Last year's ATB only included base year values and did not include projections. The learning rate results in a 10% cost reduction by 2035 for the low cost projection.

Conventional Technologies

- **Updated conventional technologies to AEO 2016**
- **Updated natural gas and coal fuel costs to AEO 2016**
- **Added higher capacity factor coal and natural gas entries—coal and gas technologies now have a fleet wide capacity factor entry and a "maximum" capacity factor entry**
- **Included more information around current costs**
- **Extended capital cost reduction trajectories that ended in 2040 out to 2050**

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Conventional capital costs from the AEO 2016 Reference scenario declined linearly from 2030-2040. This linear decline was simply extrapolated through 2050 to produce the 2040-2050 cost projections.

Summary of Changes from 2015 ATB to 2016 ATB

- **Land-based & Offshore Wind**
  - Base Year and Projections based on Wind Vision Report, unchanged from 2015 ATB.
  - Land-based TRGs expanded from 5 to 10
- **Solar PV**
  - Base Year: 2014 & 2015 costs updated based on Feldman et al. NREL/PR-6A20-64898, 2015
  - Projections: Updated UPV cost projection methodology to be literature-based (previous method was based on SunShot targets only)
  - Added commercial and residential PV Base Year and Projections using the same methodology as UPV
- **Solar CSP**
  - Base Year: Default representation is 10-hours of Thermal Energy Storage (2015 ATB had 6 and 12 hours)
  - Projections: High case uses current costs
  - Mid case assumes steady cost reduction and that CSP hits SunShot targets in 2030 (similar to 2015 ATB)
  - Low case projection assumes that CSP hits SunShot targets in 2025 based on new technology development assumptions from On the Path to SunShot; Low case includes learning rate for post-2025 cost reductions
- **Geothermal**
  - Base Year: Supply curves updated based on newer version of GETEM; added summary table to illustrate range across technology and resource
  - Cost projections are now included—The mid cost case keeps costs constant over time, the low cost case incorporates learning based on AEO 2015 (last year's ATB did not include geothermal projections)
- **Hydropower**
  - Base Year: Supply curves updated with published ORNL Hydropower Cost Report (same as Hydropower Vision); added summary table to illustrate range across technology and resource.
  - Cost projections now included—Projections are from 2016 Hydropower Vision report
- **Conventional**
  - Updated conventional technologies to AEO 2016
  - Updated natural gas and coal fuel costs to AEO 2016
  - Added higher capacity factor coal and natural gas entries—now coal and gas technologies have a fleet wide capacity factor entry and a "maximum" capacity factor entry
  - Included more information around current costs
  - Extended capital cost reduction trajectories from 2040-2050

Recent ATB Uses

- **Environmental Protection Agency**
  - Used in the final rule of the Clean Power Plan (CPP)
  - Used in climate/water modeling scenarios
- **NERC, Midwest ISO (MISO), PJM**
  - Adopted RE component for CPP-related analyses
- **Rhodium Group, Union of Concerned Scientists, Environmental Defense Fund, Resources for the Future, Sustainable Energy Economics, Global CCS Institute, Institute for Integrated Energy Systems (Canada), Comisión Nacional de Energía (Chile)**
  - Used for modeling, LCOE comparison, cost data
- **Hawaii Electric Company (HECO)**
  - Used to inform upcoming resource plan
- **Bureau of Land Management**
  - Solar Energy Zones modeling
- **Department of Energy**
  - Various electricity sector analysis

FY16 activities that will be considered in 2017 ATB

- **Land-based Wind**
  - Base Year: 2015 COE Review publication may be used if different from Wind Vision projections for 2015.
    - Potential Publications: NREL 2015 COE Review, planned September 2016
  - Projections: Survey of wind industry experts conducted through IEA Wind Task 26 – Cost of Wind Energy to elicit estimates for cost reduction levels for land-based, fixed-bottom offshore and floating offshore wind through 2050. Paper may include comparison to refreshed literature survey of cost projections.
    - Potential Publication: LBNL/NREL journal article TBD, plan to submit summer 2016
- **Offshore Wind**
  - Base Year: New supply curves that represent distance, depth, fixed, floating technologies impact on CAPEX and O&M in development to support WWPTO Offshore Wind Strategy document; number of TRGs TBD
    - Potential Publications: NREL 2015 COE Review, planned September 2016; DOE Offshore Wind Strategy, planned summer 2016
  - Projections: IEA Wind Task 26 survey described above; Offshore Wind Strategy under development by DOE WWPTO may include technology pathways through 2020 or 2030
    - Potential publications: LBNL/NREL journal article TBD, plan to submit summer 2016, DOE Offshore Wind Strategy, planned summer 2016
- **Hydropower**
  - Base Year: No changes anticipated as we are already incorporating Hydropower Vision in the 2016 ATB
  - Projections: No changes anticipated as we are already incorporating Hydropower Vision in the 2016 ATB

FY16 activities that will be considered in 2017 ATB

- **Geothermal**
  - Base Year: Geothermal Vision Study includes revised Base Year estimates
  - Projections: Geothermal Vision Study includes bottom-up component-level analysis of future cost estimates for hydrothermal and EGS resources and technologies
    - Potential Publications: DOE Geothermal Vision Study, planned
- **PV**
  - Base Year: Feldman et al. PV cost reporting
  - Projections: On the Path to SunShot studies include bottom-up component-level analysis of future cost estimates for utility, commercial and residential PV plants through 2030
    - Potential Publications:
- **CSP**
  - Base Year:
  - Projections: Paper with bottom-up component-level analysis of future cost estimates for power tower technologies with storage in development; updated supply curves in ReEDS needed to reflect new technology. Funding still under consideration.
    - Potential Publications: NREL Technical Report, planned summer 2016 – funding still under consideration

Acknowledgments

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