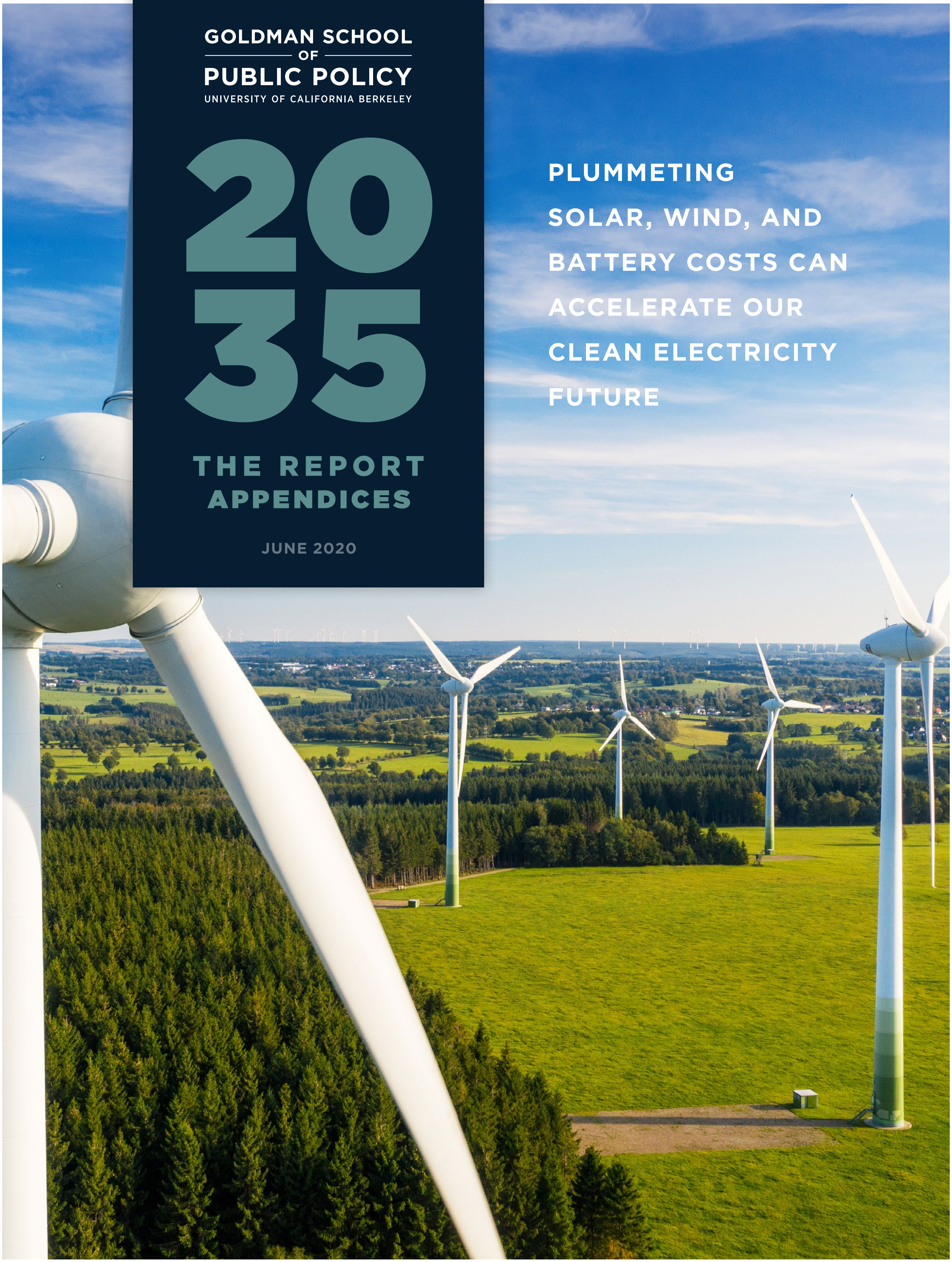
GOLDMAN SCHOOL OF PUBLIC POLICY
UNIVERSITY OF CALIFORNIA BERKELEY

2035

THE REPORT APPENDICES

JUNE 2020

PLUMMETING SOLAR, WIND, AND BATTERY COSTS CAN ACCELERATE OUR CLEAN ELECTRICITY FUTURE



APPENDIX 1
CONTRIBUTIONS OF THIS STUDY TO THE LITERATURE

The 2035 Report draws from and expands on a growing body of literature and methodologies that explore high-renewable and low-carbon power systems. All studies grapple with a number of key issues, such as cost, emissions, and operations of a regional or national power system. Most of this literature examines reaching a high-renewables future by 2050. All must take into account — or risk being undermined by — rapidly changing costs and capabilities of new energy technologies, such as wind, solar, and battery storage.

For example, only a few recent analyses take into account the recent declines in battery storage costs and explore their role at scale to cost effectively integrate variable renewables. Storage is a rapidly scaling trend, with more than a quarter of renewable energy capacity in interconnection queues (about 70 GW) already paired with about 30 GW of storage as of 2019. The proliferation of low-cost battery storage has large implications for system planners, in part because storage can reduce the need for balancing of variable renewable generation through other means. MacDonald et al., for example, assessing complete decarbonization of the U.S. power sector by 2030, relies on an expansion of inter-state and inter-regional transmission, rather than storage.[1]

Several studies focus on the goal of 100% renewable energy or complete decarbonization of the power sector, rather than cost-effective interim goals, as in our study. Other power sector studies are done in the context of economy-wide decarbonization, using clean electricity to clean up other sectors such as transport, buildings, and industry. Studies vary on whether they quantify environmental and health benefits of decarbonization and assess the employment and investment impacts.

Our study attempts to build on the existing literature and address some of these gaps by assessing deep, but not complete, decarbonization on an accelerated 2035 timeline; by using the latest renewable energy and storage cost estimates, informed by prices observed in the market; and including an assessment of environmental and health benefits and employment impacts.

1 MacDonald, A., Clack, C., Alexander, A. et al. Future Cost-Competitive Electricity Systems and Their Impact on US CO_2 Emissions. *Nature Climate Change* 6, 526–531 (2016).

BRIEF LITERATURE REVIEW

In this section we provide a brief overview of a few notable studies that illustrate the different approaches that have been applied at the national, regional, and state level, by national labs, university researchers, and consulting firms.

Some common themes emerge from this literature:

- Rapidly falling clean energy technology costs can quickly make the results of studies obsolete; even aggressive assumptions about future cost declines have been surpassed over the past decade.
- Transmission is a key variable in studies. Renewable energy resources are site-specific, causing researchers to look at the tradeoffs between renewable generation sources sited close to load and power imported from other regions.
- Studies use different strategies for variable generation load balancing, such as by relying on energy storage, flexible clean supply, more interconnected transmission, and demand flexibility.
- Studies must also deal with seasonal variation in renewable generation, such as periods of low wind and solar energy output. Emerging or pre-commercial technologies such as long-term energy storage and flexible nuclear generation are often included, although their technical and economic performance is uncertain.
- A number of studies focus on complete decarbonization of the power sector, and the technical and economic barriers involved. This approach can overlook opportunities for large carbon reductions to happen more rapidly and overstate certainty about future problems given unknown rates of technology deployment and potential breakthroughs.

National Studies

NREL (2012)

Renewable Electricity Futures

A comprehensive and pioneering study that used modeling tools to account for the time and location aspects of renewable generation and demand. It looks into the technical feasibility of high levels of renewable energy on the U.S. power grid, focusing on an 80% renewable by 2050 case. While the study finds this level is feasible by 2050, it finds that the wholesale power costs increase by $25-$50/MWh above baseline.

Novacheck, Brinkman, Porro, NREL (2018)

[Operational Analysis of the Eastern Interconnection at Very High Renewable Penetrations].

NREL used high fidelity tools to demonstrate that a 70% renewable (wind and solar) system in the Eastern Interconnect was operable at the 5-minute level. This was done without battery storage or major transmission expansion.

Frew, et al., NREL (November 2019)

[Sunny With a Chance of Curtailment: Operating the US Grid with Very High Levels of Solar Photovoltaics].

NREL used linked capacity expansion and production cost models to study the operational impacts of a future U.S. power system with over half of annual power coming from solar PV combined with short-term storage. Load and operating reserve requirements can be met for all hours, with storage used mostly during sunset hours. Under the highest PV penetration scenario, hours with over 90% solar penetration are relatively common. Rapid transitions between solar and conventional synchronous generation occur, along with more economic curtailment of solar and frequent hours with very low energy prices.

Sepulveda, Jenkins, de Sisternes and Lester, MIT (2018)

[The Role of Firm Low-Carbon Electricity Resources in Deep Decarbonization of Power Generation]

This MIT study says that "firm" low-carbon technologies (nuclear, natural gas with carbon capture and sequestration, and bioenergy), reduce electricity costs by 10%–62% in deep decarbonization scenarios compared to cases without such resources. The study modeled supply and demand in a "northern" system based on New England and a "southern" system based on Texas. It found that firm low-carbon resources are particularly valuable in regions with more modest renewable energy potential like New England. The study showed without firm low carbon resources, cost only increased once the system got above approximately 80% variable renewables.

Jenkins, Luke and Thermstrom (2018)

[Getting to Zero Carbon Emissions in the Electric Power Sector]

This literature review organizes 40 deep decarbonization studies published since 2014 into two paths: one that relies primarily (or even entirely) on variable wind and solar power supported by energy storage, greater flexibility from electricity demand, and continent-scale expansion of transmission grids; and a second path that relies on wind and solar plus "firm" resources such as nuclear, geothermal, biomass, and fossil fuels with carbon capture and storage (CCS). The review finds that emission reductions of 50-70% are much easier than higher or complete decarbonization, and that firm low-carbon resources are a consistent feature of the most affordable pathways to deep decarbonization of electricity.

MIT Joint Program on the Science and Policy of Global Change (September 2019)

Deep Decarbonization of the U.S. Electricity Sector: Is There a Role for Nuclear Power?

This MIT report examines whether new nuclear power capacity can play a role in achieving deep decarbonization of the electricity system. It finds that wind and solar are the most cost effective resource until they reach 40% penetration, and 60% under low-carbon policies with current nuclear costs. If nuclear LCOE costs fall to 5¢/kWh, nuclear plays a much larger role and significantly reduces the carbon price needed to achieve a 90% carbon reduction in the electricity sector.

Energy Innovation, the Regulatory Assistance Project, and Grid Strategies (June 2019)

Wholesale Electricity Market Design for Rapid Decarbonization

Analysts produced a series of three papers that explored which wholesale market design would be best for low carbon power systems. One model, dubbed the "Robust Spot Market," suggests tightening up and extending today's markets for energy and services, eliminating capacity markets, and extending today's practice of voluntary decentralized bilateral contracting. The "Long-Term Plus Short-Term Markets" approach envisions complementing those more robust energy and services markets with an advanced, centralized, forward market to support needed resources and services.

MacDonald, Clack, Alexander, Dunbar, Wilczak & Xie (January 2016)

Future Cost-Competitive Electricity Systems and Their Impact on

US CO_2 Emissions

Using high resolution weather data, this study shows that wind and solar generation can cut carbon dioxide emissions from the U.S. electricity sector by up to 80% relative to 1990 levels, without an increase in the levelized cost of electricity. The reductions are possible with current technologies and without electrical storage. The study focuses on moving away from a regionally divided electricity sector to a national system enabled by significantly expanded high-voltage direct-current transmission.

Jacobson, Delucchi, Cameron, and Frew (December 2015)

Low-cost Solution to the Grid Reliability Problem With 100% Penetration of Intermittent Wind, Water, and Solar for All Purposes

This study from Stanford and UC Berkeley researchers looks at how to solve reliability issues with a 100% "wind, water, and solar" power supply. It envisions electrification of all U.S. energy sectors (electricity, transportation, heating/cooling, and industry) and uses wind and solar time series data from a global weather model. Solutions are obtained by prioritizing storage for heat (in soil and water); cold (in ice and water); and electricity (in phase-change materials, pumped hydro, hydropower, and hydrogen), and using demand response. No natural gas, biofuels, nuclear power, or stationary batteries are needed. Thanks in part to reduced environmental damages, the full social cost is lower than for fossil fuels.

Budischak, Sewell, Thomson, Mach, Veron, and Kempton (Journal of Power Sources, March 2013)

Cost-minimized Combinations of Wind Power, Solar Power and Electrochemical Storage, Powering the Grid Up To 99.9% of the Time

Researchers from the University of Delaware modeled combinations of wind and solar generation with battery storage, incorporated into a large grid system (72 GW), with four years of load and weather data. It finds that the least cost solutions have large amounts of generation capacity—at times, almost three times the electricity needed to meet electrical load—with lower amounts of storage. At 2030 technology costs and with excess electricity displacing natural gas, the study finds that the electric system can be powered 90%–99.9% of hours entirely on renewable electricity, at costs comparable to today's—but only if the mix of generation and storage is optimized.

REGIONAL STUDIES

New England

Brattle Group (September 2019)

[Achieving New England's Ambitious 2050 Greenhouse Gas Reduction Goals Will Require Keeping the Foot on the Clean Energy Deployment Accelerator]

> Cutting carbon 80% by 2050 across the New England economy could double demand for electricity, and require 4-7 GW of new clean generation investment each year. Current rates of investment are about 830 MW per year, requiring a substantial increase in ambition.

New England and New York

Sustainable Development Solutions Network in collaboration with Evolved Energy Research and Hydro-Québec (April 2018)

[Deep Decarbonization in the Northeastern United States and Expanded Coordination with Hydro-Québec]

> This regional study analyzes what would be required to achieve deep decarbonization in New England and New York. It identifies the "three pillars" of decarbonization: greater energy efficiency, lower carbon intensity of electricity, and electrification of heat and transport. According to the report: "When they occur together, there is a multiplicative effect on emissions reductions."

Mid-Atlantic

McKinsey (February 2020)

[A 2040 Vision for the US Power Industry: Evaluating Two Decarbonization Scenarios]

> This study looks at a "deep decarbonization" of the Pennsylvania-New Jersey-Maryland (PJM) Regional Transmission Organization, with 95% emission cuts by 2040, vs. a "status quo" case based on current policies, which leads to an emissions cut of 49% by 2040. The study finds very large growth of wind power, and an ongoing role for gas for load balancing, though with utilization rates falling sharply.

Pacific Northwest

Clean Energy Transition Institute (June 2019)

[Challenge of Our Time: Pathways to a Clean Energy Future for the Northwest]

This is an "economy-wide deep decarbonization pathways study" for Idaho, Montana, Oregon, and Washington. In the central case, the power sector cuts emissions by 96%, retaining about 4% of annual generation from gas while eliminating coal. The net cost is about 1% of regional GDP.

STATE STUDIES

California

California Energy Commission (June 2018)

Deep Decarbonization in a High Renewables Future Updated Results from the California PATHWAYS Model

A study for the California Energy Commission by Energy & Environmental Economics (E3) used the California PATHWAYS model to evaluate ten long-term economy-wide energy scenarios through 2050, each designed to achieve a 40% greenhouse gas reduction by 2030 and an 80% reduction by 2050. It found, among other things, that the estimated 2030 cost of reducing emissions by 40% is likely to range from a savings of 0.1% to costs of 0.5% of California's gross state product, and the societal benefits of the greenhouse gas reductions achieved are likely to outweigh these costs.

Minnesota

Vibrant Clean Energy (July 2018)

Minnesota's Smarter Grid: Pathways Toward a Clean, Reliable, and Affordable Transportation and Energy System

This study offers pathways and analysis of how Minnesota could transition from its current energy system to one that is decarbonized 80% (from 2005 level) by 2050. The decarbonization would include the entire economy and is assumed to include energy efficiency measures, electrification, and generation changes. The study models the entire U.S. portion of the Eastern Interconnection along with electricity trade between the U.S., Mexico, and Canada. These scenarios are evaluated against a baseline scenario that assumes minimal electrification and no additional climate policies beyond those already enacted into law.

Minnesota, California, Pacific Northwest

Energy & Environmental Economics (E3), December 2019

Research on high levels of renewable energy in Minnesota, California and the Pacific Northwest

A set of studies by E3 “has produced remarkably consistent results: reducing power sector GHG emissions by 80% or more is both achievable and affordable.” However, they say that going to 100% with only variable renewables and short-duration storage would be “massively, unsustainably expensive.” Maintaining gas, with very low utilization, would maintain reliability at a low cost.

New Jersey

New Jersey Board of Public Utilities (January 2020)

2019 New Jersey Energy Master Plan: Pathway to 2050

This plan was produced by multiple state agencies to identify a clear roadmap for achieving “100% carbon-neutral electricity generation and maximum electrification of the transportation and building sectors” by 2050. Research in support of the plan found that “New Jersey can cost-effectively reach its goals [by] electrifying the transportation and building sectors, promoting energy efficiency, and meeting more than a doubling of load growth with 94% carbon-free electricity (the remaining 6% can be provided with carbon neutral electricity). Technical details are included in the IEP Technical Appendix (Evolved Energy Research, November 2019).

Washington

State of Washington Office of the Governor and Office of Financial Management (2016)

Deep Decarbonization Pathways Analysis

Evolved Energy and the Deep Decarbonization Project conducted energy modeling “to design and evaluate scenarios that reduce GHG emissions in Washington by 80 percent below 1990 levels by 2050.” Three different scenarios were presented, with costs ranging from $6 billion per year more to $6 billion per year less than a reference case (about 0.6% of state GDP).

APPENDIX 2
METHODS, COST ASSUMPTIONS, AND LIMITATIONS

METHODS

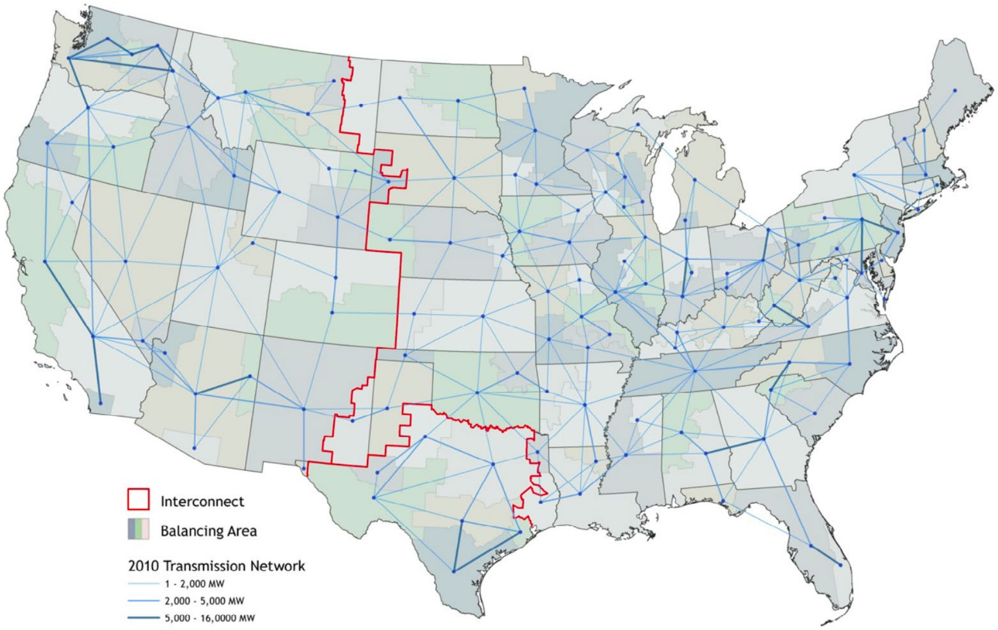
The state of the art methodology for studies that assess the impacts of high renewable energy penetration on electric power systems is to use capacity-expansion models, production cost models, or a combination of the two. For this study we use a combination of a capacity-expansion model, Regional Energy Deployment System (ReEDS) from the National Renewable Energy Lab (NREL), and an industry-standard production cost model, PLEXOS from Energy Exemplar.

Capacity Expansion

Capacity expansion models look out over a future time period, determining the optimal resource mix to meet peak and annual energy requirements at the lowest cost. Larger scale regional or national models like National Energy Modeling System (NEMS), Integrated Planning Model (IPM), and ReEDS are typically used to evaluate different federal policies and forecast how these policies will affect electric generators. Capacity expansion models can look at generation, transmission, or attempt to co-optimize generation and transmission deployment. Most capacity expansion models rely on simplified dispatch methodologies, and thus do not allow for unit commitment or hourly dispatch, and do not produce detailed plant operation outputs.

ReEDS identifies the least-cost portfolio of power sector assets in generation (by technology and fuel), storage, and transmission that meet regional electric power demand requirements, based on grid reliability (reserve) requirements, technology resource constraints, and policy constraints. The U.S. power system is represented by 134 interconnected zones which primarily represent key load balancing areas (Figure 1). These 134 zones are connected by 310 transmission lines. ReEDS includes all existing generation and high-voltage transmission assets up to 2018. In future years, it also includes the planned capacity addition and retires generation assets at the end of their technical life. Renewable resource (primarily wind and solar) potential and generation in ReEDS is taken from the Wind Integration National Dataset (WIND) Toolkit and the National Solar Radiation Database (NSRDB). Wind and CSP resource data is represented by 356 resource regions, subdivisions of 134 zones, which offers additional granularity in the variability. Please refer to the ReEDS documentation for additional details (Brown et al. 2019).[2]

2 Brown, et al. Regional Energy Deployment System (ReEDS) Model Documentation: Version 2019. National Renewable Energy Lab. March 2020.



Source: Brown (2019)

FIGURE 1.

ReEDS Balancing Areas and Transmission Network

Grid Dispatch

To assess the operational feasibility, we simulate hourly dispatch of generators, storage, and transmission ties for the year 2035, using PLEXOS, an industry-standard production cost model that is used by grid operators and utilities worldwide.[3] Production cost models optimize unit commitment and hourly economic dispatch using variable costs and operational constraints for a given power generation mix and transmission capacity to meet electricity demand at least cost.

Using the U.S. Energy Information Administration's (EIA) generator level data and operational constraints, we model more than 15,000 existing generators in PLEXOS split into 134 regions. We map ReEDS regions to PLEXOS, and use transmission line limits used in ReEDS for the 310 transmission lines/connections modeled in PLEXOS. We then use the generation and transmission expansion and retirement outputs from ReEDS, including renewable energy generators, and add them on top of the existing system in PLEXOS. We simulate the hourly grid dispatch and operations in 2035 for seven weather years (2007-

3 Energy Exemplar. Energy Market Modelling.

2013), over 60,000 hours in all, using time synchronized hourly wind, solar, and load data at the regional level.

To get hourly profiles of solar and wind generation, we use the supply-curve approach, using data from the National Renewable Energy Lab (NREL). NREL's WIND Toolkit gives hourly profiles of wind generation for 126,000 candidate sites nationally, selected using certain key criteria such as resource quality, proximity to the existing transmission and load centers, and land exclusion constraints, such as bodies of water, protected lands, and urban areas.[4] The total capacity from these 126,000 sites adds up to around 2TW. Within each ReEDS resource region (356 total), we choose the best resource quality sites from the candidate sites until we reach the ReEDS optimized installed capacity in that region. We then add the hourly generation profiles of all chosen sites within each resource region to create resource region level profiles for the given wind portfolio. If a resource region does not have enough sites to meet the capacity requirement from ReEDS, we scale up the capacity from all the candidate sites within the region to match the requirement.

NREL's National Solar Radiation Database gives hourly radiation data (global horizontal, direct normal, and diffuse horizontal irradiance) and meteorological data for each 2km by 2km grid cell within the contiguous U.S.[5] We use NREL's System Advisor Model Software Development Kit (SAM SDK) to convert the hourly radiation and meteorological data into power output.[6] Within each ReEDS zone (134 total), we choose 50 grid cells at random, and spatially average the power output data over the zone. Note that if the ReEDS output changes, the hourly wind generation profiles used in PLEXOS would also change, but not the solar generation profiles.

ESTIMATING THE TOTAL COST OF GENERATION

New Investments

ReEDS outputs capital investment in new generation and transmission assets (starting in 2010, with actuals up to 2018). We annualize the investment costs by using a real weighted average cost of capital (WACC) of 2.75% (5.25% nominal) per NREL Annual Technology Baseline (ATB).[7] We also run a sensitivity case using a high financing cost (5.5% real or 8% nominal). ReEDS also outputs the operations and maintenance (O&M) costs (fixed and variable) and fuel costs of the existing as

4 National Renewable Energy Lab. Wind Toolkit.
5 National Renewable Energy Lab. National Solar Radiation Database.
6 National Renewable Energy Lab. System Advisor Model.
7 National Renewable Energy Lab. Annual Technology Baseline (ATB).

well as new generation capacity.

Existing Assets

ReEDS does not report the investment cost of generation capacity built before 2010, which we estimate exogenously. First, we assess the undepreciated value of generation assets built before 2010, using data from EIA Form 860 for plant-level specifications. For conventional technologies, we use the NREL ATB 2019 capital cost assumptions, shown in Table 1, to assess the total value of each generating plant during the commissioning year.

TABLE 1.

Capital Cost Assumptions for Existing Power Plants in $/kW ($2018 real) in $/kW ($2018 Real)

TECHNOLOGY	$/KW ($2018 REAL)
Hydro (NSD1)	7,277
Coal	4,036
Nuclear	6,742
Gas-CCGT	927
Gas-CT	919
Geothermal (Hyd-binary)	5,918
Biopower	3,990

Source: NREL ATB (2019)

We add $1000/kW to all coal power plants to reflect the cost of installing emission control equipment.

We then apply a straight line depreciation method to estimate the remaining economic value for every generation plant, assuming an economic life of 30 years for all technologies except batteries. For batteries, we use an economic life of 15 years. We use the average utility WACC, 6.2% (real), to annualize these costs of the existing capacity and then add them to our total costs.

For newer technologies such as wind and solar PV, we use historical capital costs from Wiser et al. (2019)[8] and Bolinger et al. (2019).[9] For example, wind capital costs start at approximately $3,000/kW in the 1990s dropping to around $1,400/kW by the late-2000s, with a weighted-average capital cost of $1,600/kW in 2018 real dollars.

Estimating Environmental Impact Costs

We rely on the literature to estimate the value of environmental and public health damages. ReEDS outputs the total CO_2, SO_2, and NO_x emissions by technology and 134 grid regions. Using the state-level mortality factors from Thind et al. (2019), we estimate the total premature deaths due to SO_2 and NO_x emissions in each state.[10] Using the value of statistical life (VSL) from Holland et al. (2020)[11] and a social cost of carbon value derived from Baker et al. (2019)[12] and Ricke et al. (2018)[13], we estimate the total environmental damage by multiplying VSL with premature deaths due to SO_2 and NO_x emissions, and by multiplying the social cost of carbon with total CO_2 emissions from the power sector.

Results are presented in Appendix 4.

COST ASSUMPTIONS

Optimism about high levels of renewable energy by 2035 comes primarily from the rapid decline in prices for wind, solar, and battery technologies. Actual costs in recent years have been lower than those previously projected for the 2030-2035 time frame by the Department of Energy, NREL, and research firms.

Outdated cost assumptions in previous studies have led to retail electricity rate increases under high renewable penetrations. Even cost projections out to 2050 have been beaten by today's costs in some cases, including NREL's landmark Renewable Electricity Futures Study. With today's lower technology costs, hitting high renewable levels appears feasible sooner, and at little to no cost increase.

In the 2035 Report, cost and performance data for generators,

---

8 Wiser, R., M. Bolinger. 2019. 2018 Wind Technologies Market Report. Lawrence Berkeley National Laboratory.

9 Bolinger, M., J. Seel, and D. Robson. 2019. Utility-Scale Solar: Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States – 2019 Edition. Lawrence Berkeley National Laboratory.

10 Thind, M.P.S., C.W. Tessum, I.L. Azevedo, and J.D. Marshall. 2019. Fine Particulate Air Pollution from Electricity Generation in the US: Health Impacts by Race, Income, and Geography. *Environmental Science & Technology* 53(23): 14010–14019.

11 Holland, S., Erin T. Mansur, Nicholas Z. Muller, Andrew J. Yates, (2020) "Decompositions and Policy Consequences of an Extraordinary Decline in Air Pollution from Electricity Generation", *American Economic Journal: Economic Policy*, forthcoming in Volume 12, Issue 4, November 2020.

12 Baker, J.A, H.M. Paulson, M. Feldstein, G.P. Shultz, T. Halstead, T. Stephenson, N.G. Mankiw, and R. Walton. 2019. The Climate Leadership Council Carbon Dividends Plan. Climate Leadership Council.

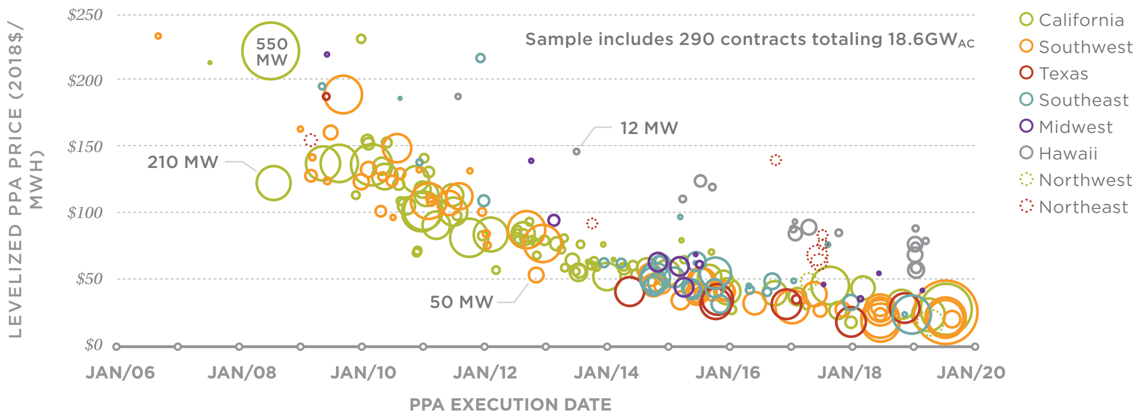
13 Ricke, K., L. Drouet, K. Caldeira, and M. Tavoni. 2018. Country-Level Social Cost of Carbon. *Nature Climate Change* 8: 895–900.

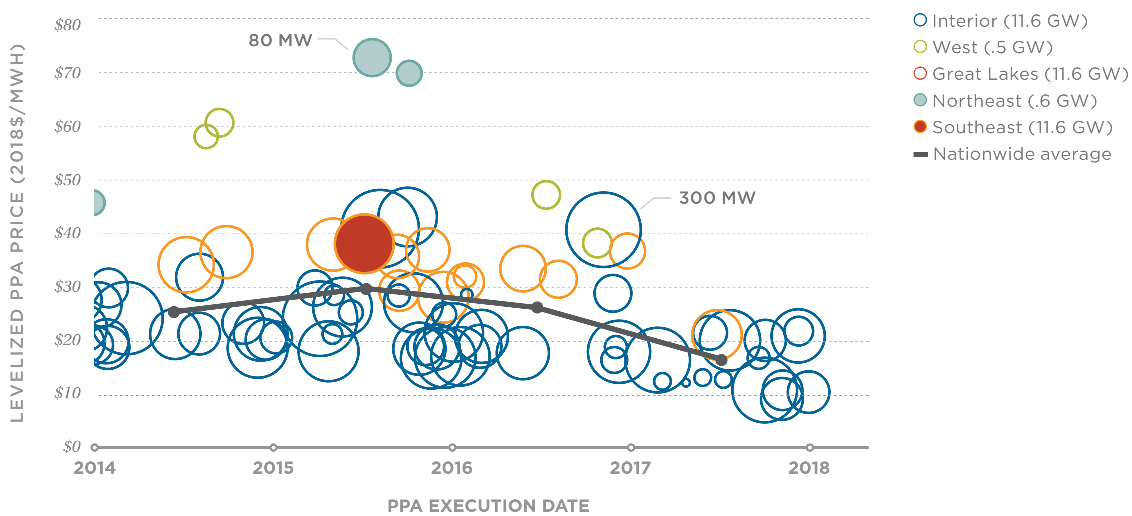
storage, and transmission is drawn from NREL's 2019 edition of the Annual Technology Baseline (ATB). The electricity sector ATB provides consistent, frequently updated, freely available, and technology-specific parameters across a range of R&D advancement scenarios, resource characteristics, sites, fuel prices, and financing assumptions for electricity generation technologies, both at present and with projections through 2050. It contains projections for capacity factor, Capital Expenditures (CAPEX), Operations Expenditures (OPEX), and Levelized Cost of Energy (LCOE) as a summary metric for electricity generating technologies. We use the ATB Mid-case and ATB Low-case in our scenarios, along with a Modified case that combines the two as our base case, using the ATB Low-case costs in 2021 (benchmarked to actual contract prices signed today), but Mid-case cost trajectory thereafter.

The Modified case was developed to account for rapidly falling prices for Power Purchase Agreements (PPA) signed by utilities in the past two years, and that anticipate commercial operation starting within the next two years. PPAs are perhaps the clearest indicator of current and immediate-future prices.

Wind and solar costs have seen steady declines in the past decade as the technologies, supply chains, and business practices have matured. As shown in Figure 2, data collected for the U.S. Department of Energy shows PPA prices for utility-scale solar and wind have dropped in recent years to a national average of $28.20/MWh for solar and to below $20/MWh for wind projects, as of 2018.[14] The lowest recorded PPA prices have reached $10/MWh for wind and $20/MWh for solar – although new records seem to appear regularly. While the lowest cost projects are in high-quality wind and solar resource areas, prices have dropped in low-quality resource regions as well. These PPA prices also include the federal Production Tax Credit (PTC) for wind and Investment Tax Credit (ITC) for solar.

14 Wiser, R., M. Bolinger. 2019. 2018 Wind Technologies Market Report. Lawrence Berkeley National Laboratory. Bolinger, M., J. Seel, and D. Robson. 2019. Utility-Scale Solar: Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States – 2019 Edition. Lawrence Berkeley National Laboratory.





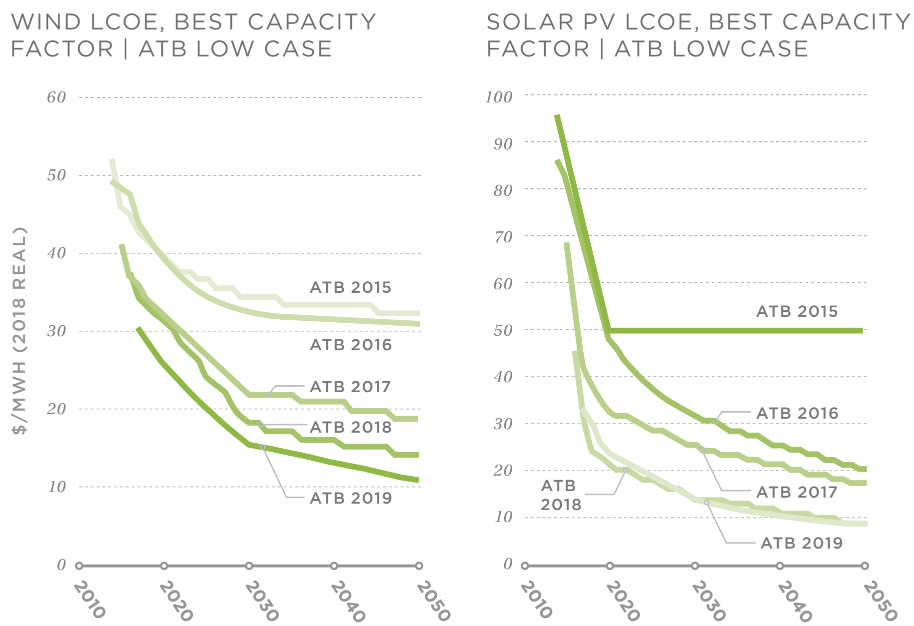
Sources: Bolinger et al. (2019) (top) and Wiser et al. (2019) (bottom)

FIGURE 2.

Power Purchase Agreement (PPA) Prices for Utility Scale Solar (top) and Wind Energy (bottom)

Since these PPA prices, when adjusted for the tax credits, trend closely to the unsubsidized costs for renewables cited in the ATB low-case for 2020 and 2021, we used them as the basis for our ATB Modified case for technology prices. However, to be more conservative about the potential for future cost reductions, we switch over to the ATB Mid-case for cost trends after 2021.

This is consistent with NREL's practice of frequently updating ATB projections to reflect the most recent market trends. As shown in Figure 3, cost forecasts in the ATB have fallen dramatically in recent years for utility-scale solar PV, onshore wind, and lithium-ion battery systems. NREL has successively lowered cost projections in each annual revision of the ATB.



Data Sources: NREL (2015-2019)

FIGURE 3.

Changes in NREL ATB Low-Case Cost Assumptions for Wind and Solar

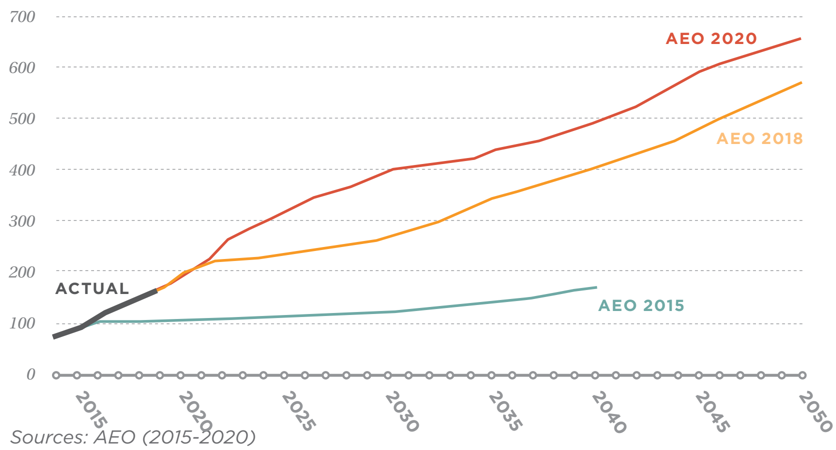
Falling current and projected prices have improved the prospects for wind and solar growth in market forecasts. As shown in Figure 4, the amount of wind and solar in each of EIA's Annual Energy Outlook's (AEO) for 2035 has tripled over the past five years, from 115 to 350 GW of cumulative capacity.[15] In the 2015 AEO, EIA expected to see 126 GW of wind and solar built by 2030; in actuality, that amount of renewables was already built by 2017.

It is important to remember that this is EIA's reference case scenario, based only on current policies. Since federal tax credits for wind and solar are currently phasing out, most of the growth in this scenario is unsubsidized. Still, other forecasters see even higher growth levels. The International Energy Agency's *World Energy Outlook 2019* sees North American renewables capacity rising from 406 GW in 2018 to 699 GW by 2030 and 892 GW by 2040. In their more aggressive "Sustainable Development" policy scenario, capacity rises to 1372 GW by 2040.[16]

15 NREL (National Renewable Energy Laboratory). Annual Technology Baseline: Electricity 2019, 2018, 2017, and 2015.

16 International Energy Agency. *World Energy Outlook 2019*. November 2019.

EIA WIND AND SOLAR GROWTH OVER TIME (CUMULATIVE GW)



Sources: AEO (2015-2020)

FIGURE 4.

Changes in Wind and Solar Growth from Annual Energy Outlook (AEO) Reference Cases

While recent cost drops for wind and solar have been remarkable, there are a number of signs that further cost reductions will be realized in coming years. The U.S. Department of Energy (DOE) is supporting wind energy research through the Atmosphere to Electrons (A2e) initiative, focusing on the fundamental science necessary to drive innovation and the realization of next-generation wind turbine designs.[17]

Battery storage costs are also seeing spectacular drops, falling 85% since 2010, with further declines expected as deployment scales up, especially to meet demand from the electric vehicle market.[18] The ATB Mid-case anticipates a decline in 4-hour duration battery prices from $380/kWh in 2018 to $194/kWh by 2035, a 50% drop. In the ATB Low-case, prices could drop to $112/kWh (NREL 2019). One recently announced utility scale solar plus storage project in California had an estimated capital cost of $310/kWh of capacity, resulting in a combined levelized cost of energy of $40/MWh.[19]

While stationary battery deployment in the U.S. was only one gigawatt (GW) in 2019, consulting firm Wood MacKenzie expects it to rise to 10 GW in 2021, and 18 GW by 2024, as prices fall

17 U.S. Department of Energy. A2e: Atmosphere to Electrons.

18 Wesley J. Cole and Allister Frazier. National Renewable Energy Lab. *Cost Projections for Utility-Scale Battery Storage*. 2019.

19 Florian Mayr, Apricum. Battery storage at US$20/MWh? Breaking down low-cost solar-plus-storage PPAs in the USA. Energy Storage News. March 23, 2020.

another 20%. Another 78 GW of utility-scale storage is "under development or contracted," much of it as part of hybrid solar plus storage plants.[20] At the end of 2019, there were about 60 GW of solar plus battery hybrid projects in the interconnection queues for the seven regional transmission organizations (RTOs), which include at least 28 GW of battery capacity. There was an additional 7.5 GW of wind plus battery projects, with over 1.8 GW of batteries.[21]

A July 2019 forecast from Bloomberg New Energy Finance expected battery storage capacity worldwide to rise from 9 GW (17 GWh) deployed as of 2018, to 1,095 GW (2,850 GWh) by 2040, along with a halving of costs by 2030.[22]

ADDITIONAL KEY VARIABLES

In addition to technology costs, study results are driven by other important variables. Table 2 summarizes key variables and assumptions, but a few warrant further discussion due to their large impacts. To see the impacts of these three variables, see the data visualization tool at 2035report.com.

Financing Costs: Since wind, solar, and battery technologies are capital intensive, with low operating and maintenance costs, financing costs have a large impact on their levelized cost of energy (LCOE). Financing costs are influenced by a number of factors, such as the prime lending rate set by the Federal Reserve (which reflects macroeconomic conditions), by alternative investment opportunities, and by the perceived risk of investment in a given technology, market, or project. These can be difficult to predict, yet can have a large impact on future investments in the energy sector. We rely on assumptions built into ATB, resulting in a weighted average cost of capital (WACC) base case of 2.75% and a high case of 5.5% in real terms.

Policy: We use two policy cases, discussed in more detail in the following Appendix: a baseline No New Policy case (assuming only existing policies in effect as of 2018, similar to the AEO 2020 reference case) and a 90% Clean case that rises from today's clean share of 40% in 2020 to 90% by 2035.[23] We include as a sensitivity scenario a carbon price case where the price begins at $10/metric ton in 2020, ramps up by $10/metric ton each year until 2023 ($40/metric ton). From 2024 onward, it follows the trajectory in Baker et al. (2019), starting at $42.5/metric ton in

20 Wood Mackenzie Power & Renewables. US Energy Storage Monitor: Q4 2019 Report. December 2019.

21 Will Gorman, et al. Lawrence Berkeley National Lab. Motivations and options for deploying hybrid generator-plus-battery projects within the bulk power system. The Electricity Journal, 33 (2020),

22 Bloomberg New Energy Finance. Energy Storage Outlook 2019. July 31, 2019.

23 The No New Policy case notably does not include the 100% clean energy standard in Virginia, or any other revisions states have made since 2019. ReEDS includes all other relevant state policy updates as of early 2019.

2024, increasing at 1.5% each year, and reaching $50/metric ton by 2035.

Gas Prices: Natural gas is the prime competitor with wind and solar power for future growth and market share. Yet price forecasts for natural gas have historically not been very accurate, due to production technology improvements (fracking), the difficulty of storing natural gas in large amounts, interactions between power generation and other end use markets, and the increasing interconnection with global markets as LNG shipping increases.[24] In the No New Policy case, lower priced gas results in less investment and market share for wind and solar, and thus higher emissions. On the other hand, low gas prices result in lower overall costs in the policy cases (90% Clean and carbon price). The base case natural gas prices are the same as in the reference case in the U.S. Energy Information Administration (EIA) Annual Energy Outlook. The low natural gas prices use New York Mercantile Exchange (NYMEX) future prices until 2023, and beyond 2023 the price of natural gas is kept constant at $2.50/MMbtu (nominal), with a floor of $1.50/MMbtu (2018 real).

TABLE 2.

Summary of Key Variables and Assumptions

PARAMETER	ASSUMPTION	IMPLICATIONS	SOURCE
Geographic Scope	Lower 48 divided into 134 zones embedded in the ReEDS model.	Simulates the current and future U.S. power system.	NREL, ReEDS model.
Technology Cost and Performance Forecasts	ATB-Modified is used in the central scenarios. We also include ATB-Low and ATB-Mid cases. The ATB-modified case uses low-case costs through 2021, then declining at the same rate as the mid-case costs.	Mid-case makes modest assumptions about price and performance gains.	NREL's Annual Technology Baseline, 2019 edition.
Distributed Solar	Deployment of distributed (customer sited) solar is taken from an external model, and then imported into ReEDS.	Current distributed solar models anticipate 39 GW of new deployment from 2020-2035.	NREL's Distributed Generation Market Demand (dGen) Model.
Operations and Maintenance (O&M)	Fixed and variable O&M costs of all non-retired power plants are included.	After 30 years of economic life, the cost of keeping a power plant online is limited to the Fixed O&M cost (in $ per kW/year).	O&M costs for generation assets taken from ReEDS. Battery O&M costs taken from PNNL and Lazard.

24 McKinsey. North American Gas Outlook to 2030. 2019.
Trevor A. Reeve and Robert J. Vigfusson. Evaluating the Forecasting Performance of Commodity Futures Prices. Board of Governors of the Federal Reserve System, International Finance Discussion Papers, Number 1025, August 2011.

PARAMETER	ASSUMPTION	IMPLICATIONS	SOURCE
Weighted Average Cost of Capital (WACC)	Base case is 2.75% real, the high case is double the base case at 5.5% real, 2.5% inflation. Tax Rate: 25.74% Debt Fraction: 60% **Base Case Financing:** Interest Rate: 3.7% ROE: 9% **High Case Financing:** Interest Rate: 7% ROE: 12.2% Each technology and a region has a slightly different WACC, depending on the technology/ region specific risks.	Results are sensitive to WACC. Higher WACC raises the cost of a high-renewable system.	NREL ATB and ReEDS.
Energy Demand	Annual and monthly amounts, along with daily and hourly load profiles, all by region.		ReEDS load: ReEDS Hourly load profile: FERC Form 714
Extreme Events Analysis (Performed in PLEXOS)	Use weather data and energy load for seven weather-years (2007-13). Weather affects both demand and wind, solar & hydro supply.	Real weather data captures weather variability by location and time, including extreme events.	Wind: WIND Toolkit (NREL). Solar: National Solar Radiation Database (NREL). Weather year synchronized historical hourly load profile: FERC Form 714
Technical Life Span	We use ReEDS assumptions, which vary by technology, as follows: Wind: 30 years Solar PV: 30 years Hydropower: 100 years Battery: 15 years Nuclear: 60-80 years Gas CT: 50 years Gas CCGT: 60 years Coal: 65 years		NREL ReEDS.
Coal Retirements	In the 90% Clean case, all coal units are assumed to retire by 2035. This is an exogenous adjustment outside of ReEDS.	Most current coal plants reach the end of economic life before 2035.	EIA Power Plant Database.

PARAMETER	ASSUMPTION	IMPLICATIONS	SOURCE
Economic Life Span	Standard amortization is 30 years, batteries are 15 years. No forced retirement of gas assets.	75% of gas generation (400 out of 600 GW) will be mostly paid for by 2035.	EIA plant database plus expansion from ReEDS.
Electrification of Buildings, Industry, and Transport (High Electrification Scenario)	Assumes growing reliance on electric vehicles, heating, and industry, per NREL Electrification Futures Study, high electrification scenario.	High electrification adds about 13% to the national annual load by 2035. Load increase in winter months is higher than that in summer months.	NREL Electrification Futures Study.[25]
Natural Gas Prices	Base Case: Pegged to EIA AEO 2020 forecasts. Low Case: NYMEX future prices until 2023, beyond 2023, prices are constant at $2.50/MMbtu (nominal), with a floor of $1.50/MMbtu (2018 real).	NYMEX price forecasts are systematically lower than EIA, making gas more competitive. Renewable generation and storage build out is sensitive to gas prices.	NYMEX and EIA AEO 2020 reference case.
Energy Policy	90% Clean: Requires a national 90% clean electricity share by 2035. No New Policy: Includes current policies, such as current state RPS. Current tax incentives phase out as scheduled in all scenarios.	90% Clean case drives development in those scenarios.	
Carbon Price	The CO_2 price begins at $10/metric ton in 2020, ramps up by $10/metric ton each year until 2023 ($40/metric ton). From 2024 onward, it follows the trajectory in Baker et al. (2019), starting at $42.5/metric ton in 2024, increasing at 1.5% each year, reaching $50/metric ton by 2035.	Coal is impacted most by a price on carbon, and phases out rapidly (along with plant age). Gas generation is made less competitive.	Derived from Baker et al. 2019[26] and Ricke et al. 2018.[27]

25 National Renewable Energy Lab. Electrification Futures Study: A Technical Evaluation of the Impacts of an Electrified U.S. Energy System. 2018.

26 Baker, J.A, H.M. Paulson, M. Feldstein, G.P. Shultz, T. Halstead, T. Stephenson, N.G. Mankiw, and R. Walton. 2019. The Climate Leadership Council Carbon Dividends Plan. Climate Leadership Council.

27 Ricke, K., L. Drouet, K. Caldeira, and M. Tavoni. 2018. Country-Level Social Cost of Carbon. *Nature Climate Change* 8: 895–900.

PARAMETER	ASSUMPTION	IMPLICATIONS	SOURCE
Transmission	Existing grid and expansion is modeled in ReEDS. ~310 line segments connecting 134 regions. Line transfer limits embedded in ReEDS.	Total investment in transmission is modest, approximately $100 billion. This adds just 0.2 cents/kWh to total system costs by 2035 in the 90% Clean case. The vast majority of transmission investments are spur line investments as opposed to bulk transmission system investments.	NREL ReEDS.
Renewable Hourly Generation Profiles	Location and time-specific output from wind and solar generation.	Reflects actual weather data from 2007-2013.	NREL WIND Toolkit and National Solar Radiation Database (NSRDB).
Hydropower Energy Constraints	Estimated monthly energy budgets and minimum energy generation requirements.	Captures seasonal variations in hydro output.	EIA Form 923. Existing Hydropower Assets, 2019, Oak Ridge National Laboratory. EIA Form 860.

DESCRIPTION OF CASES

The four key variables described above — technology costs, policy cases, financing costs, and natural gas price forecasts — were combined to generate 24 unique cases.

TABLE 3.

Summary of Unique Cases

TECHNOLOGY COSTS	POLICY CASES
• Low (ATB Low) • Base (ATB Modified) • High (ATB Mid)	• No New Policy • 90% Clean
FINANCING COSTS	**NATURAL GAS PRICES**
• Base (WACC = 2.75% real) • High (WACC = 5.5% real)	• Base (AEO 2020) • Low (NYMEX Futures)

In discussing the results, we focus on two central cases: a clean case called 90% Clean and a "business as usual" case called No New Policy. The central 90% Clean case was developed using a 90% Clean Energy Standard policy, base technology costs, base financing costs, and base gas price forecasts. The Clean Energy Standard was intended to include commercially available generation sources with near-zero lifecycle greenhouse gas emissions, such as wind, solar, biopower, geothermal, nuclear, and hydropower.

The 90% Clean case was compared with the No New Policy case, which utilizes base technology costs, base financing costs, and base gas price forecasts. The No New Policy case assumes achievement of state and federal policies currently in place as of early 2019. This baseline case was benchmarked against the EIA's Annual Energy Outlook 2020 reference case, and had similar results.

Results from the full suite of cases are available through a data explorer at 2035report.com.

APPENDIX 3
DETAILED RESULTS

OVERVIEW OF RESULTS

By controlling four sets of key variables, we were able to generate 24 unique cases. To simplify reporting in the main text of the report, we focused on two main cases, a 90% Clean case and a No New Policy or baseline case, with base technology, gas, and finance costs.

Each of these four variables — policy, technology cost trends, natural gas prices, and financing costs — has implications for overall energy costs and emissions.

Table 4 presents some of the most notable or instructive cases. The table is sorted by the average wholesale price in 2035, but also presents cumulative emissions, and costs and emissions in 2035.[28] The variable with the largest impact on emissions is the policy case — whether there is a national policy toward 90% clean generation or no new policies are adopted.

28 Cumulative costs are not discounted. Because they go only through 2035, they do not include the effect of long-lived investments, such as emission and cost implications after 2035.

TABLE 4.

Summary of Selected Cases (Sorted by Cumulative Total Cost)

POLICY CASE	TECHNOLOGY COSTS	FINANCE COSTS	GAS PRICES	2035 EMISSIONS (MT CO_2)	CUM. MT CO_2	2035 $/ MWH	CUM. COST ($ BIL)	INSIGHT
No New Policy	Low	Base	Low	1,188	20,961	34.75	2,238	Lowest 2035 price and cumulative cost
No New Policy	Base	Base	Low	1,205	21,136	35.09	2,245	Baseline case with lower gas prices
90% Clean	Low	Base	Low	183	11,793	41.92	2,425	Best case 90% scenario, with lowest technology, finance, and gas costs
No New Policy	**Base**	**Base**	**Base**	**1,480**	**25,895**	**41.21**	**2,473**	**Central No New Policy case**
90% Clean	Low	Base	Base	180	14,500	43.36	2,558	Lowest 2035 CO_2
No New Policy	High	High	Base	1,743	27,356	44.80	2,583	Highest cumulative CO_2, highest 2035 CO_2
90% Clean	**Base**	**Base**	**Base**	**181**	**14,428**	**45.78**	**2,600**	**Central 90% Clean case**
90% Clean	High	High	Base	181	14,349	56.45	2,922	Highest 2035 price, due to pessimistic technology costs and higher gas prices, plus high finance costs

Figure 5 is a scatter plot showing the tradeoff between emissions and cost, for both price and emissions results in 2035 and cumulative costs and emissions from 2020 to 2035. The No New Policy cases result in lower costs but much higher emissions than the 90% Clean policy cases.

It should be noted that in both the cumulative and 2035 cases, there is significant overlap in the costs of the 90% Clean and No New Policy cases, and that differences between many cases are small. Because generation costs are similar for coal, gas, wind, and solar, the least-cost actual outcomes will be determined by relatively modest fluctuations in market variables, such as gas prices, coal economics, wind and solar technology and market evolution, and finance rates.

Technology costs, finance costs, and gas prices all serve as high-low variables, driving down costs if they are low and increasing costs if they are high. The impacts of the variables are discussed in the section on sensitivities, below.

In Figure 5, the central cases are marked with solid circles. The central 90% clean case results in cumulative carbon emissions of 14.4 billion metric tons (GT) of CO_2 compared to 25.9 GT of CO_2 in the central No New Policy case. The cumulative total cost is about 4.9% higher, not accounting for the costs of damage to the environment and public health.

In the 2035 charts, emissions in the 90% Clean case are constrained by policy, centering around 180 Mt CO_2 in that year. While all 90% Clean cases achieve the same emissions by 2035, the cases with lower gas prices enable a more rapid retirement of coal in early years, resulting in lower cumulative carbon emissions. Shifts in technology costs change energy costs, but don't change overall emissions in the 90% Clean case. Since emissions are constrained, they largely result in shifts between wind and solar generation, without affecting fossil generation. In the No New Policy cases, where the model is not required to meet a clean energy target, lower technology, finance, and gas costs result in lower emissions as well.

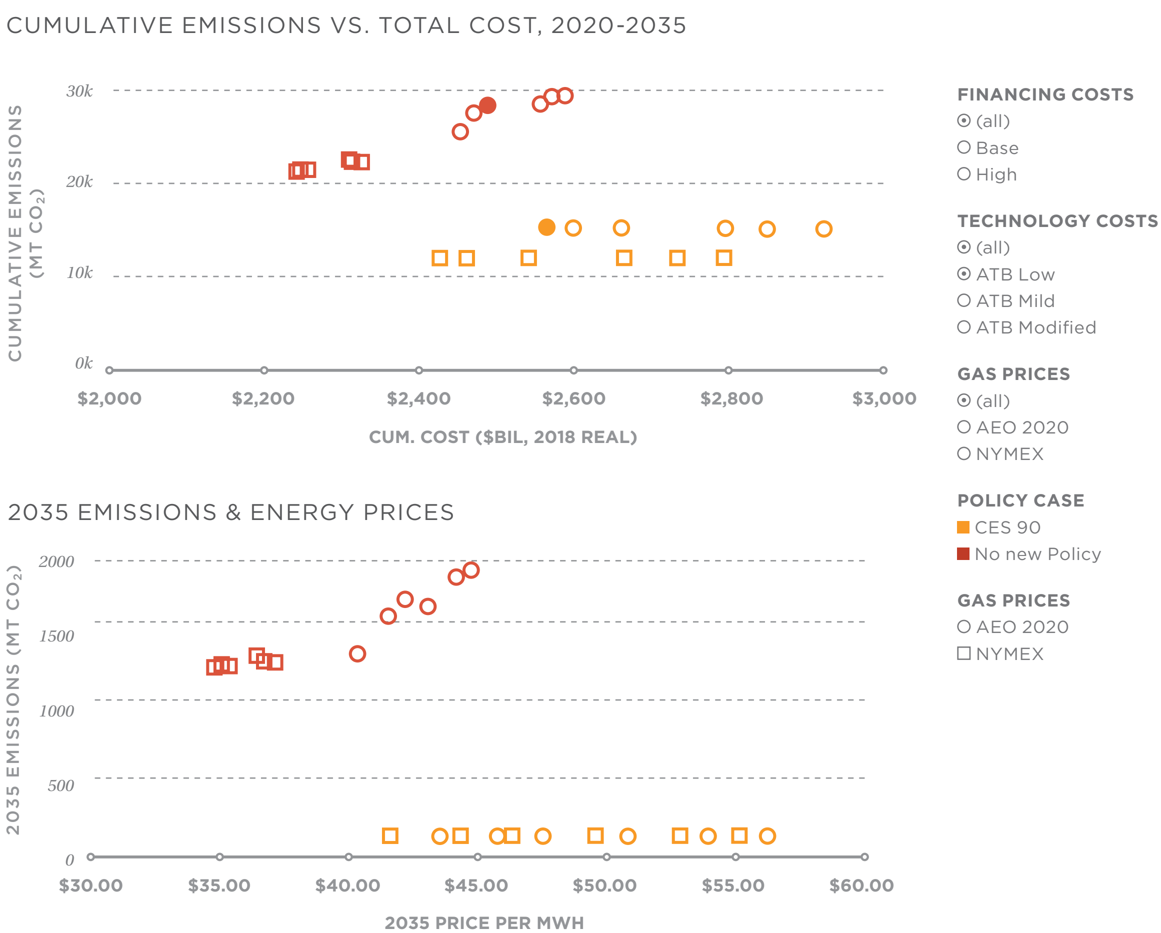


FIGURE 5.

Summary of 24 Cases, Cumulative (top) and 2035 (bottom)

While cumulative costs and emissions from 2020 to 2035 are important metrics, they do not capture trends beyond 2035. Infrastructure built before 2035 may continue to operate for many years, affecting energy prices and emission rates after that time.

Trends Over Time

Different cases result in different trends over time, with varying mixes of capacity expansion and energy generation. A data explorer allowing the user to compare the impact of the variables is available at 2035report.com. Figure 6, below, is a static image of the data explorer.

With no new policies, modeling shows a decline in prices and emissions by 2035. Most new demand is met with wind and solar, while coal and gas generation see little change. Low natural gas prices result in substantial growth in natural gas generation, taking market share away from coal, wind, and solar.

The central 90% Clean case also sees a decline in prices, and a huge decline in carbon emissions, thanks to very large growth in wind and solar generation, a complete phase-out of coal generation, and greatly reduced generation from natural gas plants. In this case, wind rises to 45% of total generation by 2035 while solar contributes another 25%. Nuclear and hydro add up to 20% of supply, while gas provides the remaining 10%. In the low gas prices variant of the 90% Clean case, lower gas prices cause combined cycle gas generation to displace coal more rapidly.

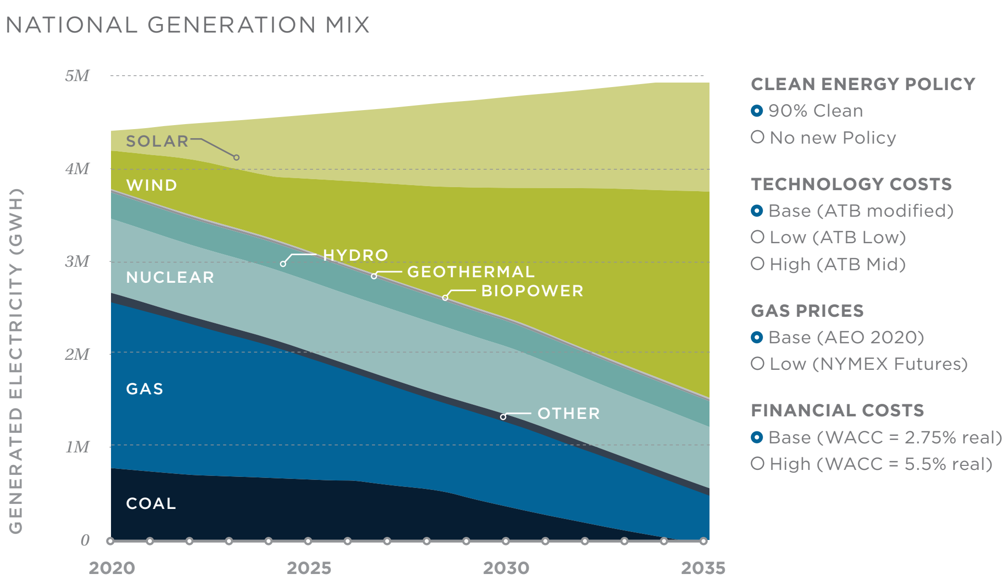


FIGURE 6.

National Generation Mix (2020-2035) for the central 90% Clean case

To see more results, refer to the data explorer at 2035report.com.

SENSITIVITY ANALYSIS

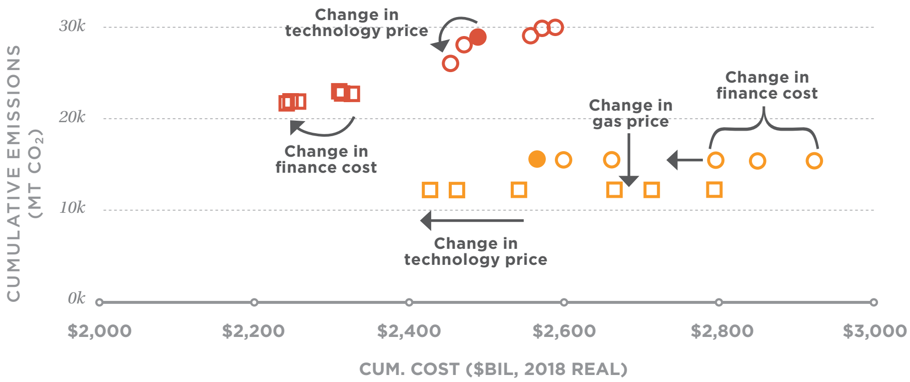
Model results change in light of key input assumptions, such as technology costs, financing costs, and natural gas prices, and vary by region. In this sensitivity analysis we explore the range of outcomes to illustrate the most influential variables.

SENSITIVITY OF COSTS AND EMISSIONS TO KEY INPUT ASSUMPTIONS

To illustrate the influence on our results of the key input assumptions described in Appendix 2, we evaluate all permutations of these variables for the No New Policy and 90% Clean cases, and a side case investigating the impacts of carbon price policies. Different cases and combinations of variables can result in dramatically different resource mixes, prices, and emissions by 2035. In addition to the policy cases, we used three technology cost, two financing cost, and two gas price cases, for a total of 24 permutations, plus 12 more in carbon price policy cases.

Figure 7 shows how changes in technology, finance, and gas costs affect cumulative and 2035 emissions and prices in the two policy cases. All three variables have the effect of changing prices, and in some cases emission levels. In the 90% Clean case (the orange marks) changes in gas price lowers cumulative emissions over the 2020-2035 timeframe. However, in 2035, since fossil fuels are limited by policy to 10% of total generation, emission levels are effectively fixed at about 180 Mt. Instead, reductions in input costs drive down energy costs, with finance costs having the biggest impact.

CUMULATIVE EMISSIONS VS. TOTAL COST, 2020-2035



2035 EMISSIONS & ENERGY PRICES

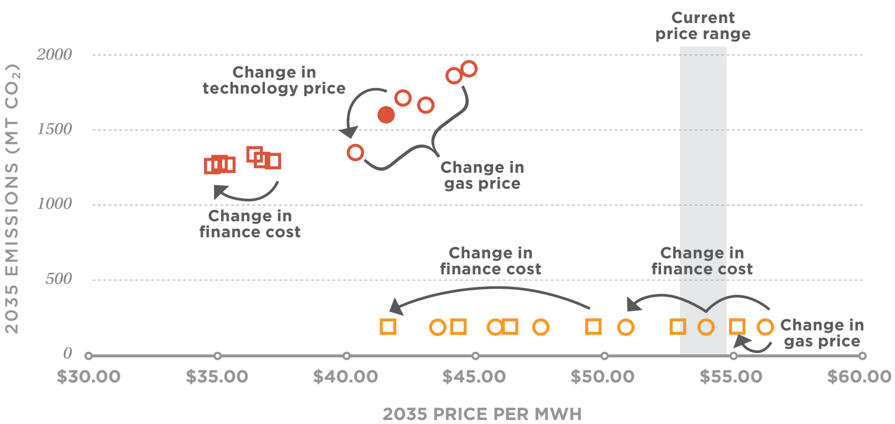


FIGURE 7.

Changes in Cases Due to Input Cost Assumptions
90% Clean cases are orange and No New Policy Cases are red. Central cases are marked by solid circles. Squares indicate low gas price cases.

90% Clean Case

Emissions are similar in all 90% Clean cases, since total clean energy generation is determined in the model by policy. The only variance is around the other 10%, which advantages gas due to the need for flexibility and its lower carbon emissions. The technology, gas, and finance cost variables thus primarily influence prices in the 90% Clean cases.

As shown by the orange marks in Figure 7, financing cost is the most influential variable in the 90% Clean case. Since wind, solar, and batteries are all capital intensive, expressed as the weighted average cost of capital (WACC), finance costs are a critical component of their levelized cost. In our base finance case, WACC is assumed to be 2.75% (in real terms), while the high financing cost case is double that, at 5.5%. In the central 90% Clean case, the change in finance costs from base to high increases the electricity price by 17% in 2035 from $45.8/MWh to $53.8/MWh.

Technology costs create a range of prices, with the ATB Low-Cost case resulting in the lowest prices overall. The difference in the gas price cases has the smallest impact on price outcomes.

The most expensive 90% clean case occurs when we assume technology, financing, and gas costs all go up together, resulting in wholesale costs of $56.45/MWh, 10% higher than the wholesale costs in 2020.

No New Policy Cases

In the No New Policy cases, shown in red marks in Figure 7, resource mix, price, and emissions outcomes are much more sensitive to technology, gas, and finance cost variables, since there are fewer policy constraints on the model. In general, high technology costs and high finance costs result in higher power prices and lower deployment of renewables, driving up emissions. Low gas prices reduce renewables deployment but also reduce coal market share by 2035, driving down carbon emissions, all things being equal.

In the No New Policy cases, gas prices — shown in the figure as circles for high price cases and squares for low price cases — have the biggest impact on costs, a 15% spread between low and high wholesale power prices in 2035. Gas prices also have a large impact on the relative market shares of gas, renewables, and coal, and thus on total carbon emissions, with an 18% difference in emissions between base and low cases. Technology cost cases have big impacts on emissions, as renewables take market share from gas. Finance costs have a modest impact on prices and little impact on emissions.

Combinations of the variables can also have significant impacts on the results. The highest emissions result from high finance, base gas, and high technology costs, resulting in coal maintaining 25% share in the generation mix by 2035 and carbon emissions rising by almost 10% over current levels. With low gas prices, coal share in the generation mix falls to only 3.5%, gas share rises to 55%, and emissions drop by 18%.

Impacts on Resource Mix

The most dramatic changes in resource mixes occur under the No New Policy case, since it has fewer constraints on cutting emissions. Figure 8 shows resource mixes for all 24 iterations of the 90% Clean and No New Policy cases.

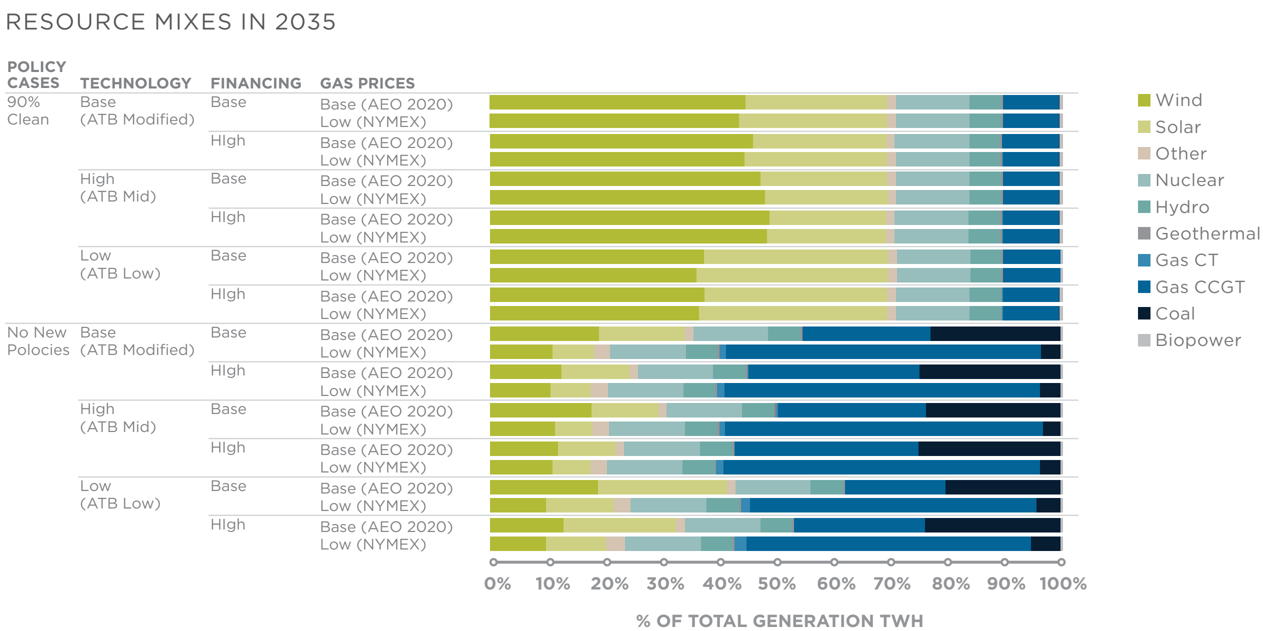


FIGURE 8.

Resource Mix of all Iterations of 90% Clean and No New Policy Cases

In the 90% Clean cases, the main variable in resource mix is the tradeoff between wind and solar power, mainly driven by NREL assumptions about technology prices in their Annual Technology Baseline (ATB). In low technology cost cases, the share of solar increases at the expense of wind, reflecting that NREL believes solar could see greater cost reductions than wind in certain cases.

For the No New Policy cases, resource mix can vary widely, and is highly sensitive to gas price assumptions. Figure 9 calls out the comparison between the low gas price case — the NYMEX case, where gas prices are as low as $1.80/MMbtu (2018 real) by 2030 — and the base gas price case (AEO 2020). Going from base to low gas prices, gas generation share increases from 22% to 55%, the share of coal generation is reduced from 23% to 3%, while solar and wind drops from a total of 34% to 18%.

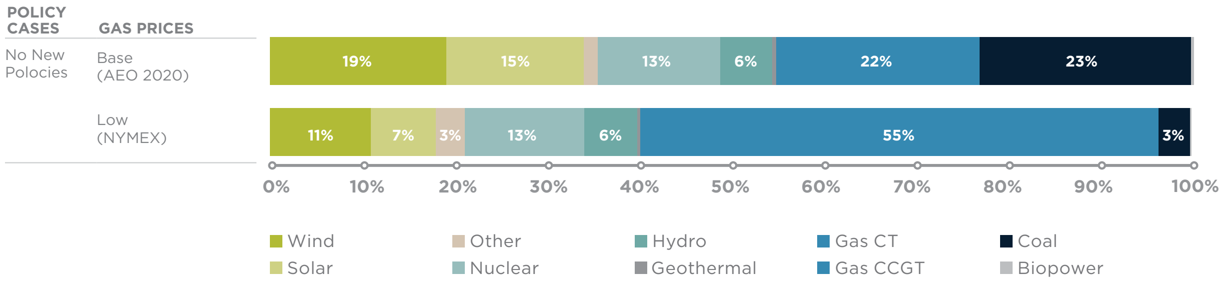


FIGURE 9.

Natural Gas Generation Share, No New Policy Case (Low Gas Prices)

CARBON PRICE SCENARIOS

The carbon price policy scenarios are substantially different than the other policy cases, so we include it here as a sensitivity scenario. Since the price differential between coal, natural gas, wind, and solar is small throughout the range of the study, charging the social cost of carbon to generators results in large changes in market share. Whether coal share goes to gas or to renewables depends largely on other factors, such as the relative gas, technology, and finance costs.

In the carbon price case, results are strongly influenced by changes to gas prices, technology costs, and the cost of capital. In Figure 10, gas price changes have large impacts on cumulative carbon emissions. Finance cost cases have a substantial impact, while technology cost assumptions have a lesser effect. In 2035, lower gas prices drive down energy prices and drive up emissions, as gas takes greater market share from renewables.

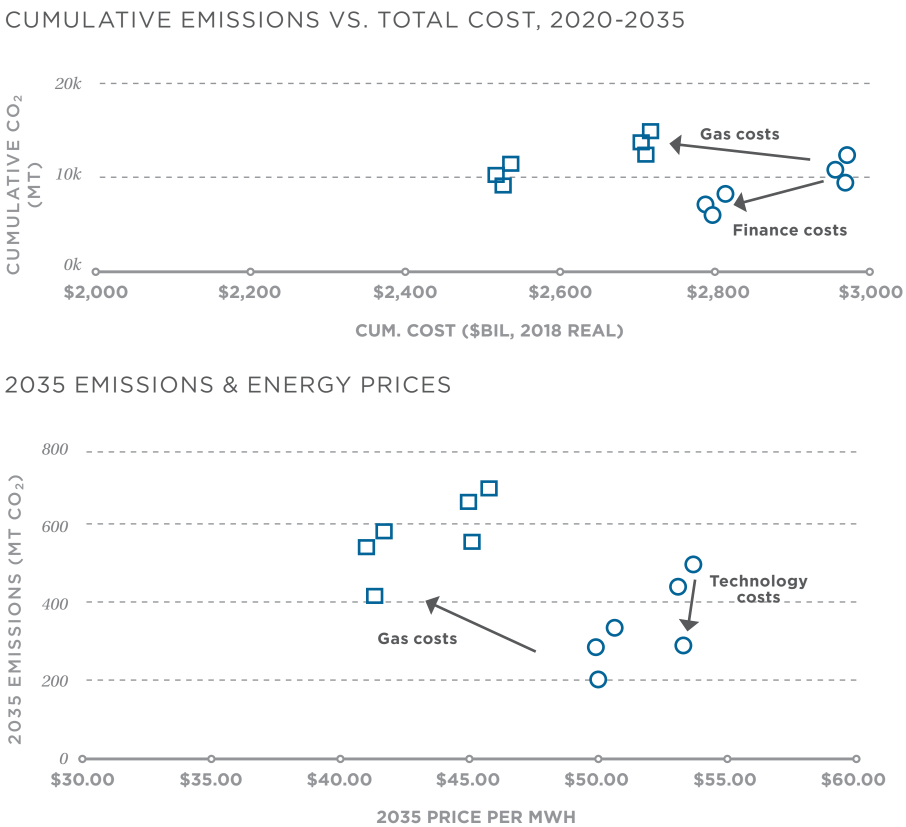


FIGURE 10.

Changes in Costs and Emissions in Carbon Price Scenario Squares indicate low gas price cases

The central carbon price case, compared to the other central policy cases, results in a more rapid retirement of coal generation in favor of gas generation in the early years. Using low case (NYMEX) gas prices pushes coal out of the mix even faster, and slightly reduces overall energy costs in interim years. In the carbon price case with the highest share of wind and solar, cumulative emissions are 75% lower than the No New Policy central case over the 15 years of the study.

The carbon price case also delivers a wider range of outcomes. For example, combined wind and solar share in 2035 ranges from 44% to 70% of generation, while gas takes between 11% and 34%. However, as discussed later in the section on capacity additions and retirements, we believe these results should be viewed with some caution. The speed that coal is pushed out of the market results in a very rapid transition from coal to wind and solar. The results do, though, underscore how competitive clean energy technologies are, and that accounting for just one of the environmental and public health externalities (damages from carbon emissions) is enough to drive rapid and substantial change in our generation mix.

IMPACT OF HIGH ELECTRIFICATION

In our modeled cases, we assume future load shapes will be similar to today's, largely driven by commercial activity (work hours), seasonal changes, and especially by air conditioning demand in the summer. In this sensitivity discussion, we assess the impact of high electrification of key end-uses such as buildings and transportation on renewable energy investments, wholesale electricity costs, and overall emissions.

We use the high electrification case in NREL's Electrification Futures Study to assess the additional load due to buildings, industrial, and transport electrification up to 2050.[29] In particular, we use state level hourly load profiles by sector and end-use, adjusting for distribution losses, with high electrification rate and rapid technology advancement, as defined in the Electrification Futures Study.[30] Nationally, the high electrification case increases load approximately 13% (609 TWh/yr) by 2035 and approximately 34% (1795 TWh/yr) by 2050 compared to the reference case. Most of the additional electrification load is due to transport sector electrification, as shown in Figure 11.

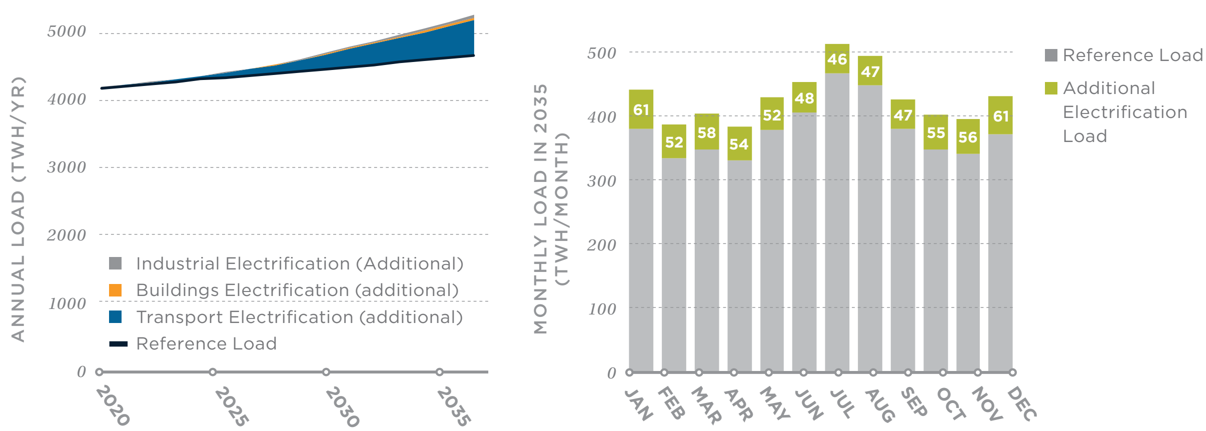


FIGURE 11.

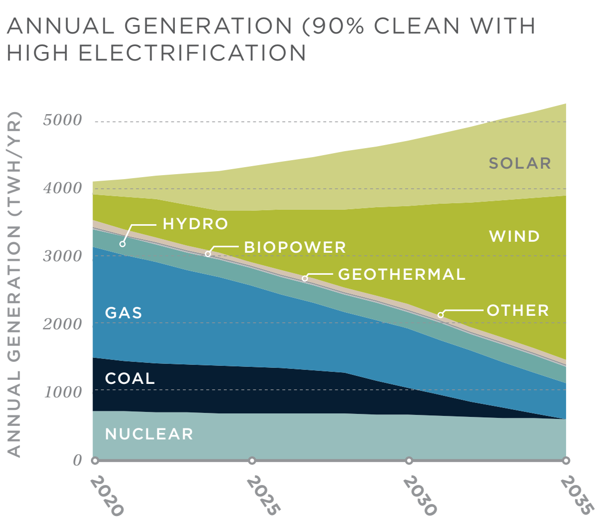
Changes to Annual Load (2020-2035) and Monthly Load Pattern (2035) in the High Electrification Case

29 Trieu Mai, et al. 2018. Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71500.

30 By 2050, High Electrification scenario projects the following end use electrification: 76% of all vehicles miles traveled in the transport sector (84% of all light duty vehicles are battery electric or plug-in-hybrids), 61% of space heating, 52% of water heating, and 94% of cooking services in the buildings sector and, 63% of curing needs, 32% of drying services, 56% of other process heating in the industrial sector.

Although total load increases from the electrification of buildings are relatively small, they are seasonal in nature, occurring mostly in winter due to space heating needs. Higher winter load, interestingly, makes the resultant annual load profile friendlier towards renewable energy. This is because even with high renewable energy penetration, the national net peak load occurs in summer (typically in July/August) with significant curtailment in winter and spring months. A higher growth in the winter load results in lower curtailment in those months, which also reduces the overall need for battery capacity.

In the 90% Clean case, to meet a 13% load increase by 2035 due to high electrification, additional renewable capacity investment would be 214 GW (95 GW Solar and 119 GW Wind), while there is a 20 GW reduction in the battery installations (Figure 12). The average cost of generation at the bulk level would be $44/MWh, 3.8% lower relative to the non-electrification load scenario ($45.8/MWh) (Figure 13).



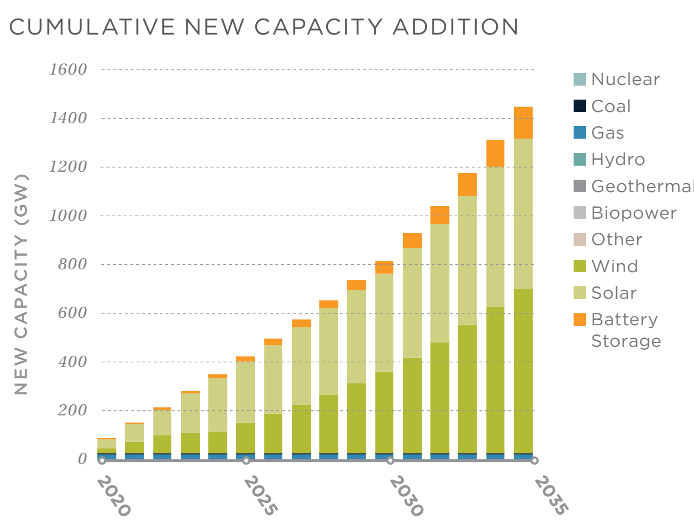


FIGURE 12.

Annual Generation and Cumulative New Capacity Addition (2020-2035), 90% Clean Case with High Electrification

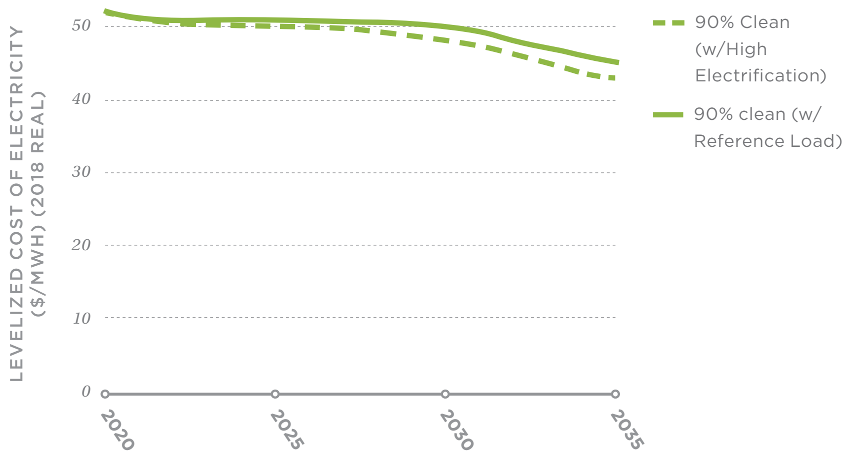


FIGURE 13.

Comparison of Levelized Cost of Electricity in Reference Load versus High Electrification Cases in the 90% Clean Case

Note that we do not consider any load flexibility, which significantly underestimates the overall system flexibility available in the model. We believe that additional electrification of buildings and transport offers additional demand response and load-side flexibility options that would further reduce the cost. Policies to unlock this flexibility are discussed in the Energy Innovation policy report (Energy Innovation 2020).

OPERATIONAL ISSUES

System Operations and Dispatch

To model the operations of a low-carbon power system, we looked at hourly dispatch at the power plant level across the United States. While ReEDS was used to assess capacity-expansion over the years of the study, PLEXOS was used to model hourly operations in 2035. Since weather is a key factor in both electricity demand and in the output of wind and solar generators, we incorporated seven years of weather data, from 2007 to 2013, to give a better sense of extreme conditions, and thus the limits of what could be expected.

The power system will see significant changes in daily supply and demand profiles, especially due to large amounts of solar and wind power. Even in the central No New Policy case, solar and wind is expected to grow to 15% and 19% by energy, respectively, of national electricity supply by 2035, with higher levels in some regions. The 90% Clean case pushes solar and wind up to 25% and 45% by energy respectively, of national electricity supply.

Since solar is a daytime-only resource, today's California phenomenon known as the "duck curve" will be endemic to all regional power systems. The duck curve, so named after how the shape of the load profile resembles the profile of a duck, features low net demand in mid-day hours, followed by a large and rapid ramp up to the net peak period in the early evening, as the sun fades before electricity demand does.[31] The extent of the afternoon ramp and timing of the net peak depends on regional weather patterns and especially on air conditioning load as a share of total demand. An important caveat, however, is that California relies much more on solar than on wind generation currently (44 TWh of solar in 2018 versus 29 TWh of wind), so the daily cycles of solar generation are not tempered by wind energy cycles.[32]

Wind and solar output across a region is not typically correlated, and can even sometimes be synergistic, depending on the resource. For example, in most regions, wind power typically peaks in the evening or nighttime periods, but has significant variability in hourly and daily output. Also, during summer peak load periods (July/August), wind energy generation drops significantly. Regions with a closer balance of wind and solar may see a less dramatic duck curve than in solar-dominated systems.

Large amounts of renewables also result in more curtailment of wind and solar generation, due to periods of excess generation relative to demand. While energy storage will be able to absorb substantial amounts of this excess generation, and shift it to use in lower generation hours, there is a point where the long-run marginal cost of adding more storage outweighs the cost of wasting clean generation. It costs less, in short, to pay producers for their curtailed power than to install enough storage to eliminate curtailment. The analysis includes the full annualized cost of wind and solar, so the costs of curtailment are included in the modeling.

In the central 90% Clean scenario, hourly national grid dispatch in each month averaged over the seven weather years is shown in Figure 14. Wind and solar are found to be reasonably synergistic at the national level, combining to provide around-the-clock supply, on average. The lowest wind output is in the summer months (July and August), with the shortcoming made up by higher solar output and greater dispatch of gas generators.

31 "Net demand" is the electricity demand remaining after wind and solar generation are subtracted from it, which indicates load that must be met by other supply resources.

32 California Energy Commission, "Tracking Progress – Renewable Energy," accessed June 2020.

Batteries are charged during the day (as shown by the hashed lines as a negative supply), helping reduce curtailment, and then discharged for the evening net peak, reducing dispatch of gas generators. The use of batteries is most pronounced in summer months.

Curtailment is highest in spring months (March through May), as wind and solar generation picks up while electricity demand for space cooling has not yet started. Curtailment is nearly absent in peak summer months (July and August) mainly owing to the high afternoon load and a significant drop in wind generation.

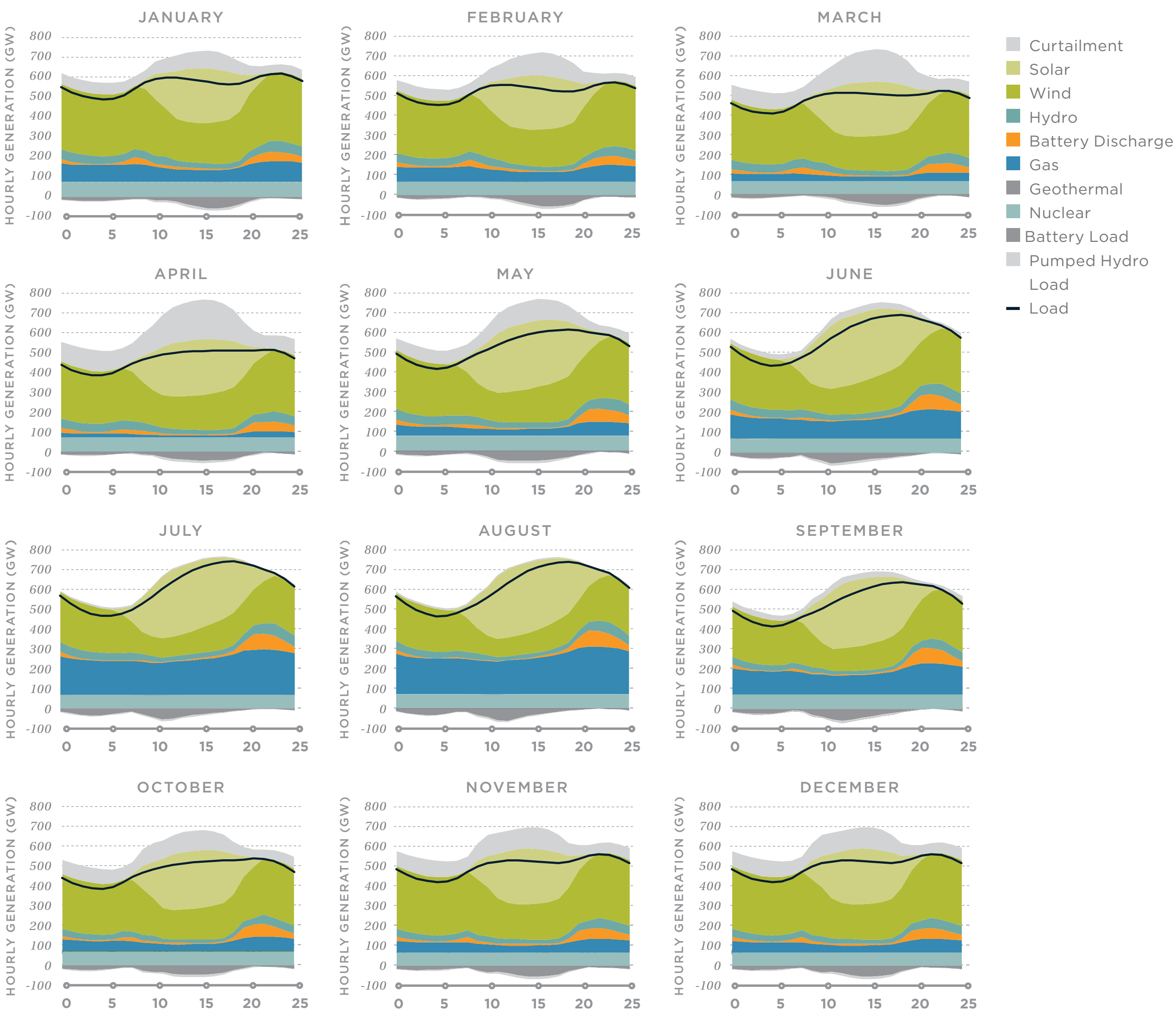


FIGURE 14.

Average Hourly Dispatch by Month in 2035

Role of Natural Gas

A novel aspect of the strategy in this study is to use already-built gas-fired power plants — sparingly — along with low cost storage to fill in the gaps in wind and solar generation. Thanks to the broad availability of wind, solar, and other existing clean assets like nuclear and hydropower, the remaining gas fleet sees very low operating hours and thus very low total emissions.

ReEDS modeling results retain about 450 GW of gas capacity by 2035 in the 90% Clean case, since the model only retires gas plants at the end of their technical life rather than for economic reasons. When we transfer that capacity to PLEXOS, which evaluates hourly operational feasibility over seven weather years, it results in a maximum of 361 GW of gas capacity used in 2035. This is about two-thirds of the 540 GW of gas capacity currently operating in the U.S. Because little to no new gas capacity is needed to meet this need, this strategy creates significant cost-savings in moving to a clean energy future.

Gas is especially useful for periods of low wind generation. Based on seven years of weather data across the U.S. (2007-2013), PLEXOS found that the hourly need for gas generation tends to be highest in August, when demand is high and wind output is low. The highest period of gas dispatch across the seven weather years in the 90% Clean central case for 2035 happens on August 1st, at 361 GW, as shown in Figures 15 and 16.

GAS GENERATION IN 2035 FOR SEVEN WEATHER YEARS

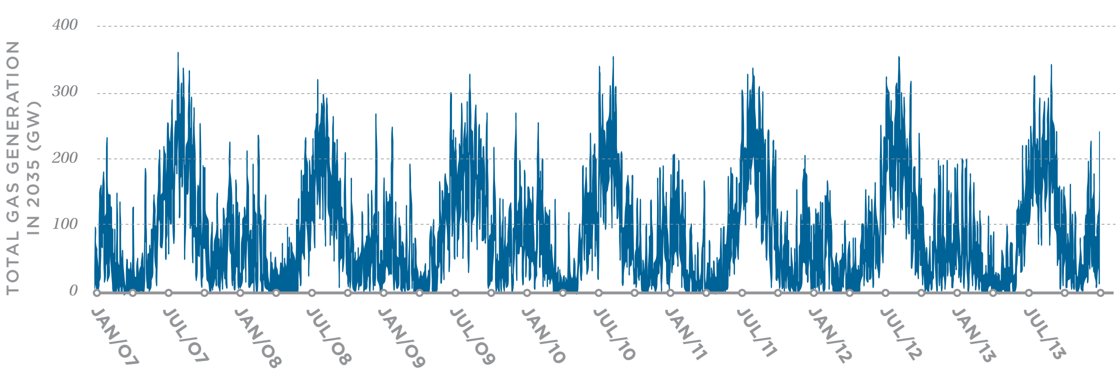


FIGURE 15.

Gas Dispatch in 2035 Across Seven Weather Years

HOURLY DISPATCH DURING THE MAX GAS GENERATION WEEK

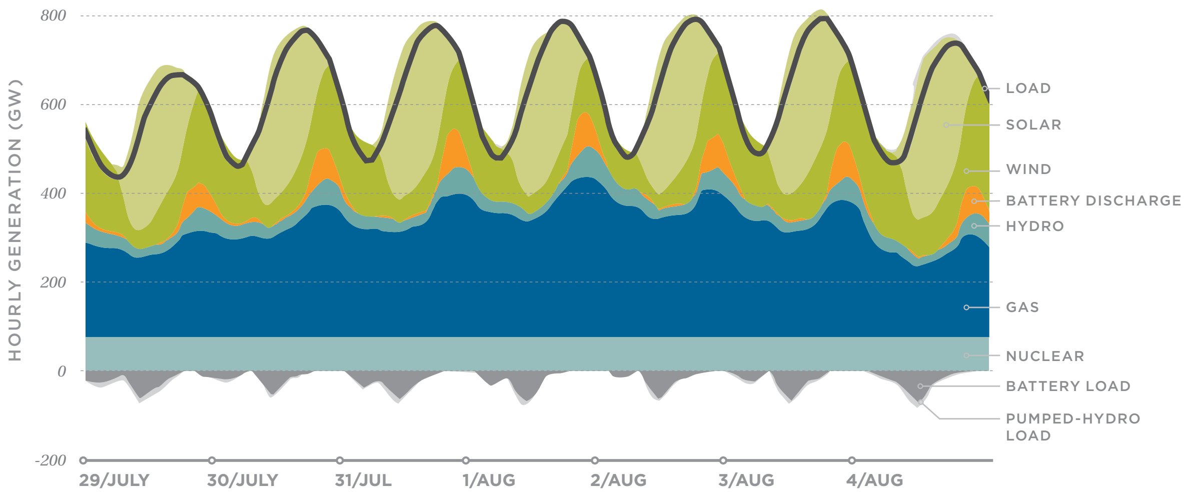


FIGURE 16.

Gas Dispatch During Maximum Gas Generation Week

Another way of understanding how often natural gas is part of the power mix is to graph a duration curve, as in Figure 17. In this duration curve, every hour of the seven weather years modeled is lined up according to the GW of dispatch required from gas plants. An interesting feature is that over 70GW of gas capacity is dispatched for less than 600 hours over seven years, or less than 1% of the time, while over 50GW of gas capacity is dispatched for less than 300 hours over seven years, or less than 0.5% of the time.

Running these final 50-70 GW of gas plants for so few hours is technically feasible, but may not be the lowest cost option to meet demand. The cost per MWh of those hours will be very high, and will invite competition from other flexible resources, such as demand response, customer-sited generators, and EV charging flexibility. Such demand side measures are difficult to model (and price), and are not included in the study. There is a good chance that they may be more attractive and lower cost than rarely used gas capacity.

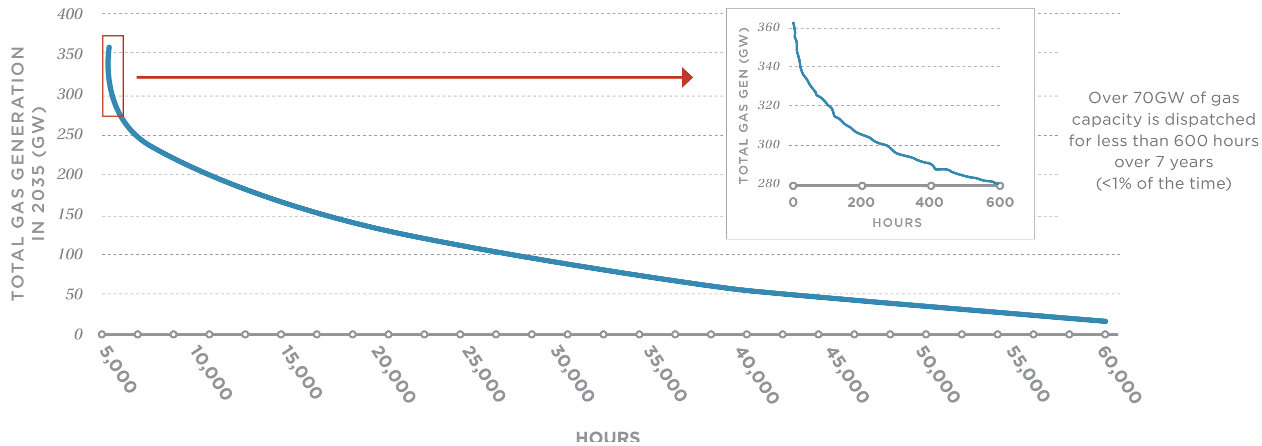


FIGURE 17.

Gas Duration Curve in 2035 Based on Seven Weather Years

Role of Storage

The 90% Clean case shows a growing deployment of conventional utility-scale battery systems, which were all assumed to be 4-hours. These short duration battery systems are primarily used to shift daytime solar generation to evening and overnight hours, and to absorb surplus generation during high-wind and high-sun hours, to reduce curtailment.

In the 90% Clean case, we anticipate about 150 GW of new battery storage will be needed by 2035. At four hours per system, that is about 600 GWh of energy storage, or 4.6% of average daily electricity demand.

We find significant variation in the level of storage needed across regions. Storage levels reflect how well generation and demand are matched, with more storage needed to shift energy from generation hours to demand hours. The highest levels are in the ERCOT (Electric Reliability Council of Texas) and RMPP (Rocky Mountain Power Pool) regions, at about 6-8% of daily energy demand.

Transmission Requirements

While previous studies have assumed that large investments in new long-distance transmission lines are needed to reach a high-renewables future, we find that the price drops and performance improvements of wind and solar generation and batteries, plus the infrequent use of gas generation, greatly reduces the need for inter-regional transfers of electricity. Lower technology costs have reduced the need for new transmission lines to connect high-quality resource areas to urban load centers. Instead, renewable generation tapping lower-quality resources, plus local storage, can be sited closer to load. The penalty for the lower output of locally-sited wind and solar is less than the cost of new long-distance transmission.

It will still be necessary to build about $102 billion of new "spur lines" connecting new generation to the bulk transmission system and local load centers. Spur line investment needed to reach 90% clean energy is approximately three times the amount forecast in the No New Policy case, but adds only 0.2 cents/kWh to total system costs in 2035. Building new spur lines, although a significant undertaking, is likely to be less daunting than major upgrades to the bulk transmission system, since spur lines tend to cover shorter distances, are often sited in rural places, and typically do not cross jurisdictional boundaries.

ReEDS models the transmission network as 310 aggregated power lines connecting 134 balancing areas (Figure 1) and spur lines which connect remote renewable resources to the larger transmission system. ReEDS includes the costs of transmission connections whenever it builds any renewable resources. ReEDS selects new generation based on both resource quality and distance to existing transmission infrastructure. The cost is included for new spur lines within a balancing area to connect new resources to the existing grid. ReEDS can also build new bulk transmission capacity to reduce congestion on the existing network.

Figure 18 shows these investments by region and interconnection. The Eastern Interconnect, which serves 72% of U.S. load, dominates the need for new spur lines, with PJM and MISO seeing the most need in the 90% Clean cases, about $40 billion in combined cumulative investment.

NEW TRNASMISSION INVESTMENT BETWEEN 2020 AND 2035

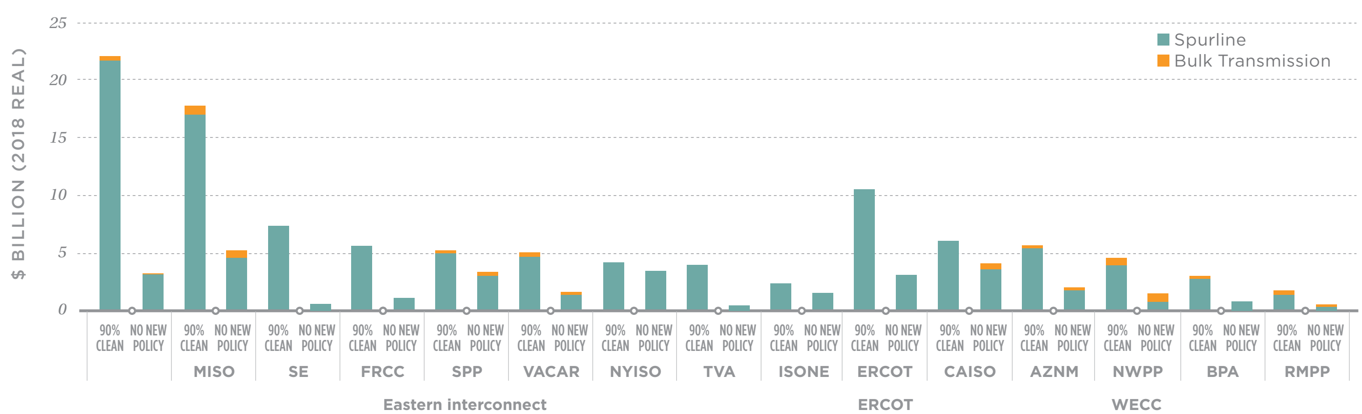


FIGURE 18.

New Transmission Investment between by Region, 2020-2035

This finding is in contrast with older deep decarbonization studies. For example, NREL's 2012 *Renewable Electricity Futures* study found a need to essentially double the size of the U.S. power grid, adding 197 million MW-miles of new transmission capacity to the existing 150–200 million MW-miles, to reach 90% renewables.[33] More recent studies have also made the case for "HVDC macrogrids" as a pathway for deep or complete decarbonization.[34]

At the time of earlier studies, wind power was the most competitive renewable source, especially in the central U.S. wind belt. The vision then was to connect large amounts of wind in the central U.S. with population centers to the east and west. The drop in technology prices means that it is now cheaper to produce electricity from a low-quality resource than to build additional transmission to access a high-quality resource. Further, low cost storage and gas generators with low capacity factors act as substitutes for bulk transmission in some hours. This finding, however, could benefit from additional study, as ReEDS may not be able to effectively co-optimize generation, transmission, and battery storage.

REGIONAL RESULTS

Regional Trends

As technology prices have plummeted, wind and solar power has become economically viable in areas with lower quality resources. While California and the Southwest still lead in solar deployment, it is rapidly spreading in other regions, such as the Southeast and Midwest. The "wind belt" across the center of the country leads in wind energy deployment, but other areas are also seeing substantial growth. Offshore wind costs have fallen in Europe, and are being imported to projects on the Eastern Seaboard, with very large projects in development off Massachusetts, New York, New Jersey, Maryland, and Virginia.

Study Results

ReEDS and PLEXOS are location-specific in modeling the capacity expansion and dispatch of power systems. Particularly important for wind and solar power, the models include renewable resource data specific to location and time of year, giving a more accurate depiction of real-world conditions.

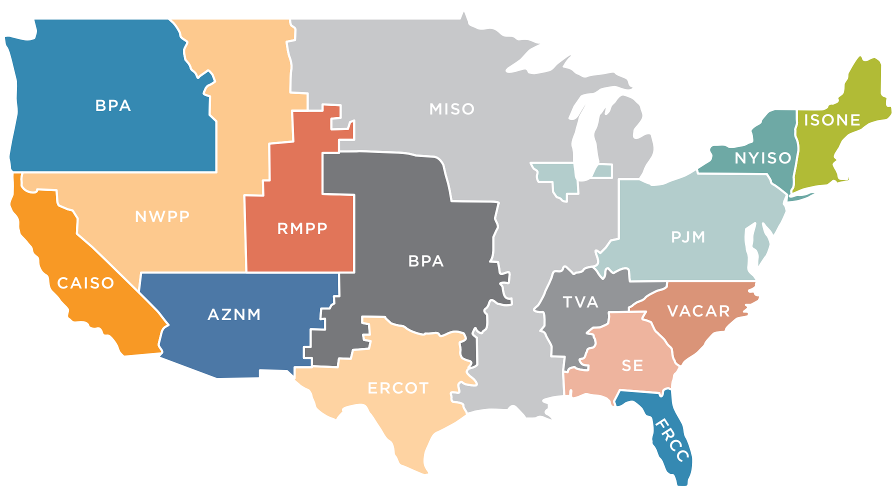
In this section we present changes to the resource mix by region,

33 National Renewable Energy Lab. Renewable Electricity Futures Study. Volume 1: Exploration of High-Penetration Renewable Electricity Futures. 2012.

34 Dr Christopher T. M. Clack. Vibrant Clean Energy. High-voltage Transmission Studies. Presentation to the International Summit on the Electric Transmission Grid. October 24, 2019.

comparing 2020 to 2035. (For a data explorer including regional results, see 2035report.com). While ReEDS and PLEXOS are state-of-the-art models, and NREL's resource data and FERC's load data is the best available, results should be taken with a note of caution at finer geographic levels, such as at the state level. Power systems have never operated at the state level, even before the advent of regional markets and grid operators. Wholesale markets can cover many states, supply and demand are matched in a balancing area which is dictated by the layout of grid circuits, and power freely flows across state lines. Many states are already energy exporters or importers, and have unequal amounts of renewable energy resources and power demand. This will increase in the future, causing some states to see high renewable percentages in their state generating mix. While ReEDS chooses optimal sites for new capacity, excluding national parks, cities, and other unsuitable areas, real-world siting decisions are driven by a number of factors that may result in different outcomes than the model.

As noted earlier, ReEDS models the lower-48 U.S. grid with 134 local zones, and can sum results up to the state, regional, and interconnect level. Since only parts of the U.S. are served by formal regional transmission operators (RTOs), ReEDS has developed a map that combines RTOs with other regions in a hybrid map to give full coverage, as shown in Figure 19.[35] Results are presented by these regions, as well as by states.



Data Source: Brown (2019)

FIGURE 19.

Map of Regions Used in ReEDS

35 Recent changes to regions, such as SPP's expansion to the north, are not reflected in this map.

In the central 90% Clean case, wind and solar grow to provide 45% and 25% of U.S. power supply by 2035, respectively, as coal is phased out and gas-fired generation falls to 10% of total share. As shown in Figure 20, the regions with the highest wind and solar mix are the Southwest Power Pool (SPP), Rocky Mountain Power Pool (RMPP), and the Northwest Power Pool (NWPP), at between 89% and 93% of generation for both wind and solar, which reflects their small loads relative to the abundant wind and solar resources in the regions. NWPP already exports significant amounts of electricity to California.

Regions that are already strong with wind power, such as MISO (Midcontinent Independent System Operator), SPP (Southwest Power Pool), and ERCOT see large future growth in wind. Solar-heavy regions like CAISO (California Independent System Operator), joined by FRCC (Florida) and the Southeast – which have seen rapid pickup of solar in the last two years – become solar leaders, at about 40% of their resource mix. MISO, which has both a large amount of load and a very large and resource-rich service territory, hits almost 80% with wind and solar power.

Storage installed capacity levels reflect how well generation and demand are matched, with more storage needed to shift load from generation hours to demand hours.

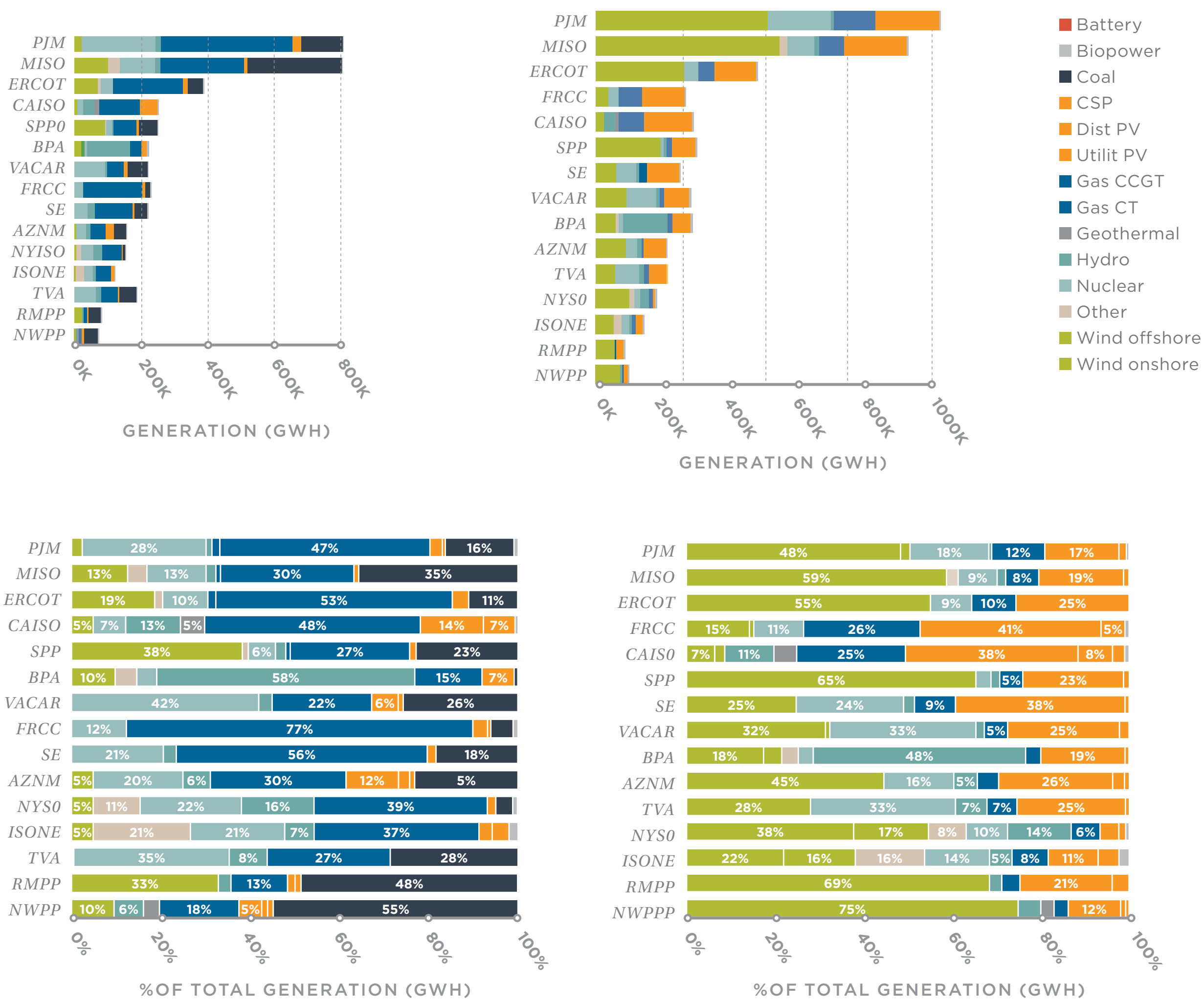


FIGURE 20.

Changes in Regional Generation Mixes, 2020 and 2035

State results are presented in Figure 21, to give a sense of where wind and solar power see the greatest potential for development. States like Iowa and Wyoming, with small populations and load, and very strong wind resources, become major energy exporters. Iowa is already at 41% wind power and its largest utility, MidAmerican Energy, plans to generate the equivalent of all their state load from state-sited wind farms by late 2020.[36] Likewise, Idaho, Nevada, and Utah, with small loads and bountiful space for solar power, see very high shares of solar power.

Existing nuclear and hydropower facilities are largely assumed to continue operations through 2035. We anticipate 20 GW of nuclear retirements by 2035, based on the age of the plants. Nuclear and hydropower retain significant share in certain

36 MidAmerican Energy, Press release: "Wind XII project positions MidAmerican Energy to hit 100 percent renewable goal," May 30, 2018.

states, such as Washington and Oregon for hydropower and New Hampshire and South Carolina for nuclear. The resource labeled "other" is primarily hydropower imported from Canada to northern states like Vermont, New York, and Washington.

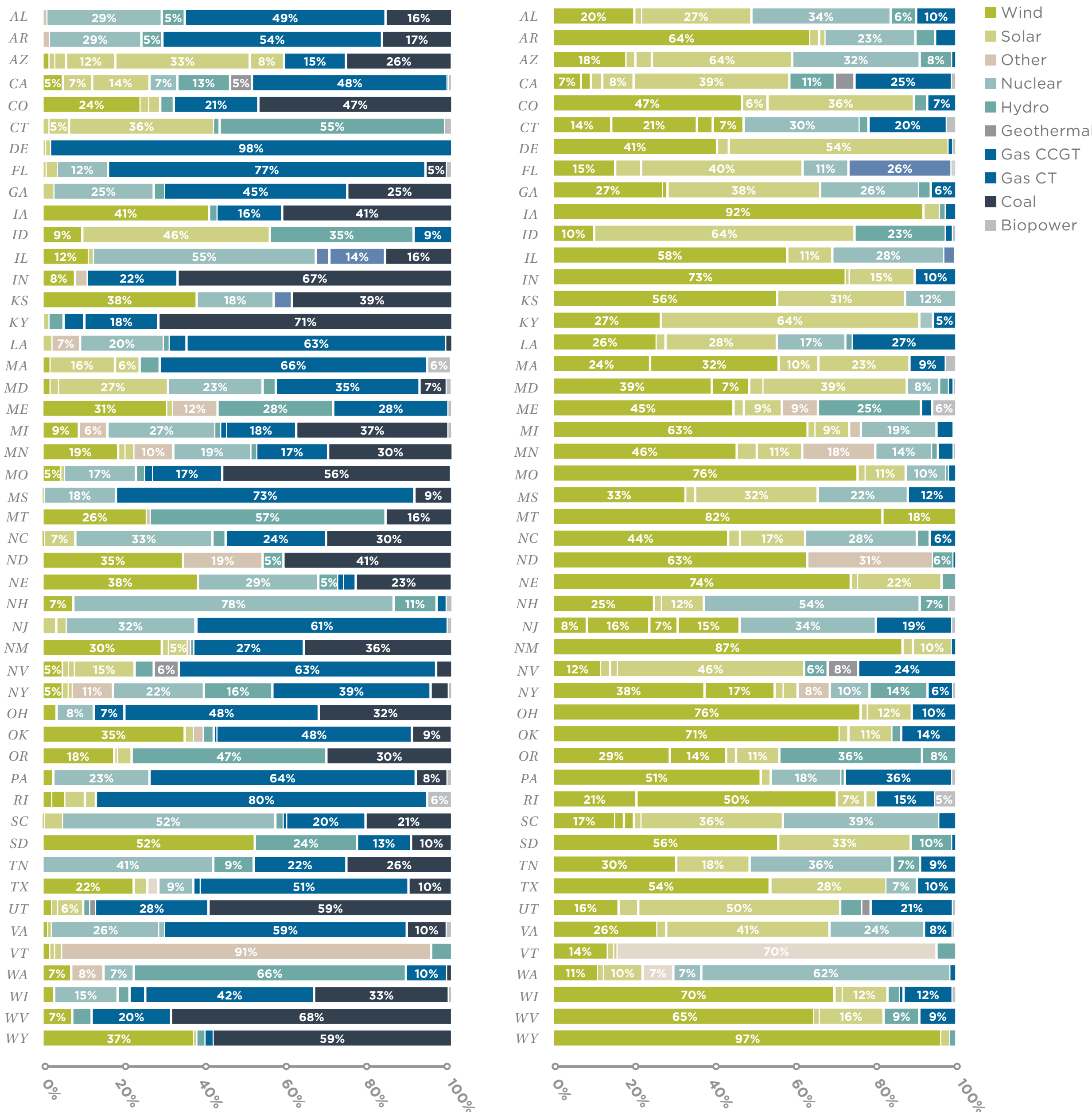


FIGURE 21.

Changes in State Generation Mixes, 2020 and 2035

ADDITIONS, RETIREMENTS, AND STRANDED ASSETS

The move to a 90% clean power system in only 15 years will require substantial deployment of wind and solar generation, along with a rapid retirement of all coal and some natural gas generation.

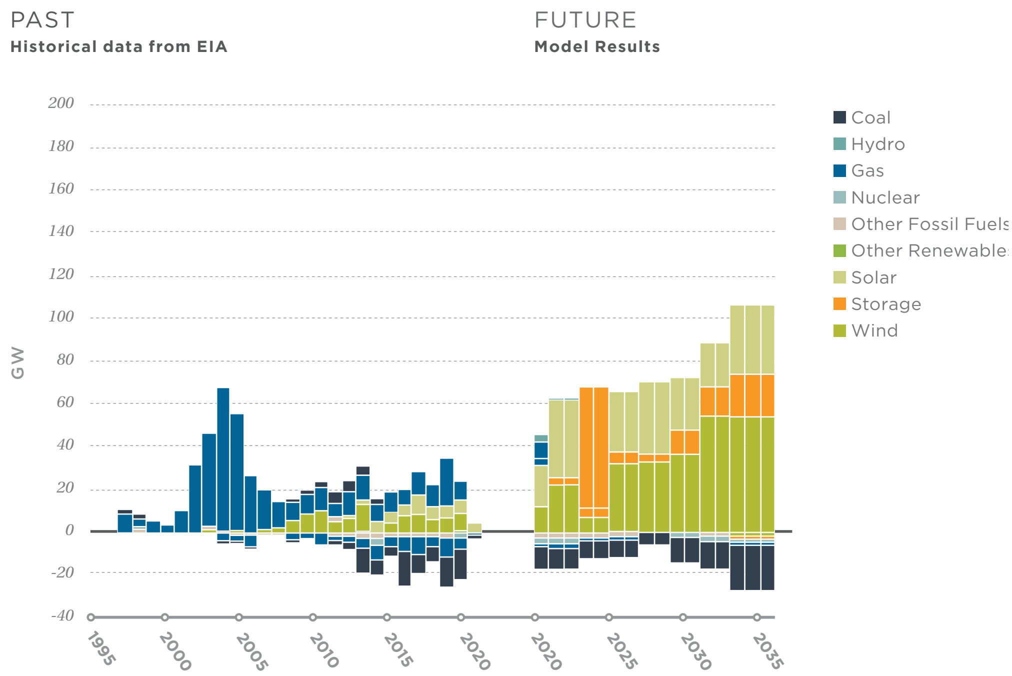
This analysis contemplates a significant rebuild of the U.S. power generating fleet. While the changes needed to substantially cut carbon emissions are significant, we argue that they are achievable, cost effective, and affordable.

In this section we provide details on the additions to generation between 2020 and 2035 that result from modeled scenarios, retirements that may be expected or accelerated, and the issue of stranded investments.

Capacity Additions

In the central 90% Clean scenario, we envision a total of 2,078 GW of generating capacity in operation as of 2035. Of this total, wind and solar comprise the largest share, at 643 and 578 GW each, respectively. We expect 447 GW of natural gas capacity operating, though with very low capacity factors.

To reach this resource mix, the 90% Clean case envisions a substantially greater level of renewable energy deployment than we have seen to date in the United States. Figure 22 shows past data from EIA on new generation capacity added per year since 1995, along with future annual additions from the 90% Clean case, through 2035.



(Data Source for Historical Data: EIA Electric Power Monthly)

FIGURE 22.

Past Additions and Retirements Compared to Future (1995-2020 vs. 2020-2035), 90% Clean Case

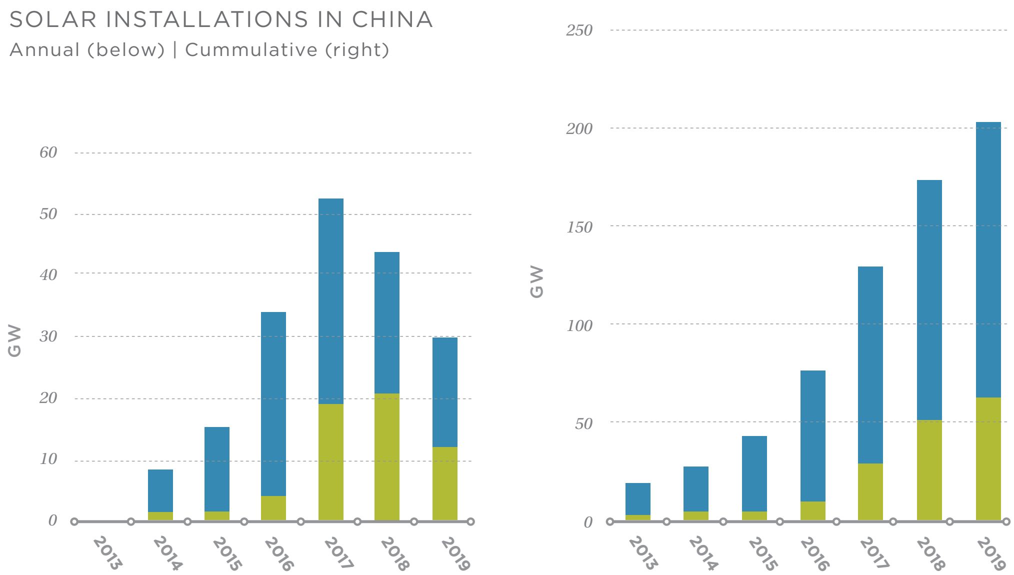
In the central 90% clean case, virtually all new capacity comes from wind, solar, and batteries. New gas additions from plants currently under construction end in 2020, while the one nuclear plant, Plant Vogtle in Georgia, is assumed to be completed by 2022.

Total deployment of new generation capacity averages 75 GW per year, including an average of 34 GW of wind and 32 GW of solar, plus 9 GW of battery storage, mostly in later years. Cumulative capacity additions reach 544 GW of wind and 505 GW of solar, plus 149 GW of batteries. Of the total solar capacity additions, 39 GW is additional distributed PV (customer-sited), and the rest is utility-scale. Distributed PV assumptions come from the NREL Distributed Generation Market Demand model (dGen) and are not optimized by ReEDS.[37] The wind installed by ReEDS is primarily onshore wind, with 26 GW of new offshore addition.

While the 90% clean scenario requires substantially more capacity additions than past experience with wind and solar

37 NREL. Distributed Generation Market Demand Model (dGen).

in the U.S., it is not out of the range of possibility. The U.S. record for new total capacity installations was in 2002, when 67 GW of new capacity came online, including 65.6 GW of new natural gas plants.[38] The largest single year for wind was 2012, when 13.9 GW was deployed, while solar saw an additional 15.1 GW in 2016. If these had happened in the same year, total renewable capacity installations would have been 29 GW. The single country record for wind installation was set by China in 2019, at 26.3 GW, a year in which China also installed 30.1 GW of solar PV. China installed almost 53 GW of solar in 2017, and a cumulative 200 GW between 2013 and 2019.[39]



Source: China Energy Portal

FIGURE 23.

Solar Installations in China, 2013-2019

The wind and solar industries respectively forecast installations of about 9 and 18 GW per year in new capacity over the next five years.[40] S&P Global counts about 100 GW of wind and solar needed in the U.S. over the next decade just to meet state renewable portfolio standard (RPS) requirements.[41]

Annual deployment hits new records after 2030, with the combined total of wind, solar and batteries exceeding 100 GW per year. This is largely due to the growth in wind and battery deployment after 2030.

38 Energy Information Administration. Electric Power Monthly. February 2020.
39 China Energy Portal. Accessed June 2020.
40 SEIA and Wood MacKenzie. Solar Market Insight Report 2019 Q4. December 2019.
41 Steve Piper, et al., S&P Global Market Intelligence. The 2020 US Renewable Energy Outlook. December 10, 2019.

Even the No New Policy case, which envisions much less new capacity investment and closely reflects EIA's Annual Energy Outlook reference case, is dominated by new wind and solar, with an average of 17 GW of solar and 9.2 GW of wind annually through 2035. As shown in Figure 24, wind, solar, and batteries make up 90% of the 500 GW added in this case.

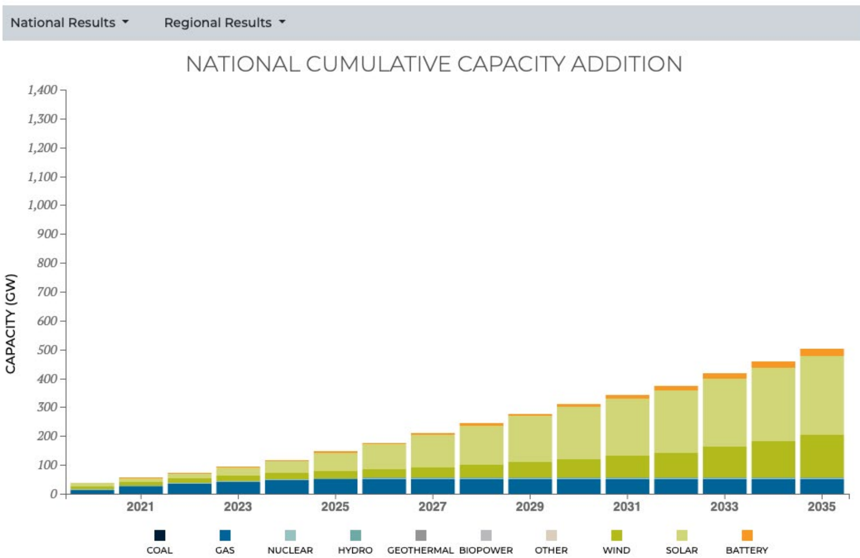


FIGURE 24.

Capacity Additions in the No New Policy Case

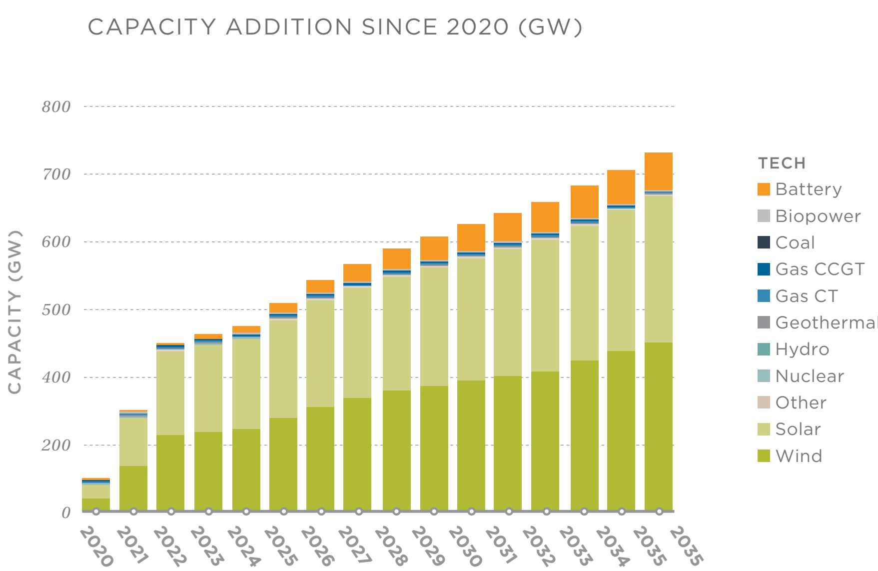


FIGURE 25.

Future Deployment in the Central Carbon Price Case

To further put these deployment levels in perspective, regional transmission organizations report 451 GW of new wind, solar, and batteries in interconnection queues as of the end of 2019, which is 85% of the total capacity in the queues.[42] Not all projects in queues actually reach construction, but they are an indicator of the level of commercial development activity at a moment in time, and are a good indicator of near-term trends.

Retirements

Another reason why a transition to clean energy generation is cost effective is the advanced age of many U.S. power plants. Age is especially a factor for coal, oil-fired steam turbines, and gas-fired steam turbines. Of the approximately 828 GW of fossil generation capacity in operation today, almost 645 GW will be 30 years or older in 2035.[43]

By then, a high percentage of that coal and older gas capacity will have been fully depreciated (given the usual depreciation life of 30 years or less), and can be retired at little to no cost to consumers and minimal risk of stranded costs for investors.[44]

The capacity-weighted average age of coal plants operating in 2020 was 41 years, a slight decline in age from previous years due to recent retirements of older plants. The average age of the 98 GW of coal plants that have retired since 2000 has been 49 years, suggesting that a large portion of the existing fleet is nearing the end of its life.[45]

Another 82 GW of natural gas plants, mostly steam turbines, has retired since 2000 at an average age of 42 years. There are currently 76 GW of gas-fired steam turbine plants operating, with an average age of 51 years. Other fossil fuel plants, primarily oil-fired units, have retired at an average age of 44 years, while there are 35 GW of oil-fired plants with a current average age of 41 years. In all, 81% of capacity that has retired in the last 20 years has been coal, gas-fired steam turbines, and oil-fired steam turbines. Another 12% has been from gas fired combined cycle and combustion turbines.

Since 2000, 557 GW of new capacity has been added to the U.S. power fleet, consisting almost entirely of gas, wind, and solar generation. This includes 261 GW of natural gas combined cycle plants, 108 GW of gas combustion turbines, and 143 GW of wind

42 Data comes from interconnection queue data from MISO, SPP, PJM, ERCOT, CAISO, ISO-NE, and NYISO.

43 EIA. Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860). February 2020 data, released April 24, 2020.

44 Many coal plants have performed capital improvements, especially for environmental control equipment, so even older plants may have undepreciated balances. We add $1000/kW to the capital cost of the existing coal plants to account for those investments.

45 EIA

and solar. By 2035, three-fourths of fossil fuel capacity currently online will be over 30 years of age, with 436 GW of that over 40 years old. By that year there will be only 26 GW of coal less than 40 years old, and 400 GW of gas.

In the 90% Clean case, we retire all coal capacity in the U.S. between 2020 and 2035 in a linear manner, starting with the power plants over 30 years of age. This is in addition to the technical retirement projected in ReEDS. On average, we retire 14 GW of existing coal capacity each year. By 2035, nearly 22 GW of coal capacity would be less than 30 years old, with an undepreciated asset value of $21 billion (2018 real).

The turnover of the generation fleet is already a strong trend, as the U.S. has seen 91 GW of coal capacity retire in the past decade, along with 55 GW of natural gas and 17 GW of other fossil fuel plants. S&P Global expects another 27 GW of retirements to happen through 2025.[46] In a December 2019 report, Morgan Stanley Research forecasted that between 70 GW and 190 GW of coal capacity was "economically at risk." Moving to renewables could save consumers between $3 billion and $8 billion per year, while cutting carbon emissions by 65-74% by 2030. Utilities would see a total renewables investment opportunity of $93 billion to $184 billion.[47]

Stranded Assets

As shown in Figure 26, we estimate that the undepreciated value of the current fleet of fossil fuel plants will fall from $320 billion today to about $75 billion by 2035, greatly lowering the capital recovery cost of those plants. The value of combined-cycle and combustion turbine gas plants will fall from $230 to $53 billion. Given the age of America's fossil fuel generating fleet, stranded assets caused by a shift to a 90% clean power system may become a minor problem by 2035.

Our calculations include about $100 billion in pollution controls and other investments made in plants since construction. Our estimates are similar to estimates from other sources, such as Rocky Mountain Institute.

46 Anna Duquiatan, et al. US power generators set for another big year in coal plant closures in 2020. January 13, 2020.

47 Morgan Stanley, *The Second Wave of Clean Energy*, December 10, 2019.

UNDEPRECIATED VALUE OF EXISTING FOSSIL ASSETS ($ BILLION)

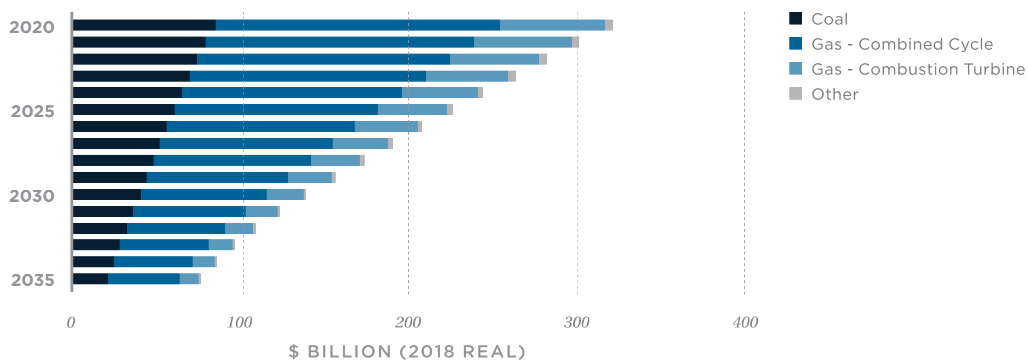


FIGURE 26.

Undepreciated Value of Existing Fossil Fuel Assets

While almost all coal plants will be well over 40 years old by 2035, a growing number of gas plants will also be nearing retirement age. In response to electricity market restructuring in the late 1990s, developers went on a spree, building an average of 43 GW per year between 2000 and 2004. Texas alone saw 30 GW of new gas capacity in those years. Of the 540 GW of gas capacity currently operating, 400 GW will be over 30 years old by 2035, and nearing retirement.

We define stranded costs as the cost of the fossil assets that are retired but have not been fully depreciated or allowed full capital cost recovery, assuming a depreciation life of 30 years. Please see the accompanying paper from Energy Innovation for further discussion on stranded assets.

In the central 90% Clean case, the cost of the remaining undepreciated value of coal plants in 2035, about $21 billion, is still paid even though the plants are exogenously retired. The capital recovery costs amount to about $0.5/MWh. This trend of low undepreciated asset values won’t be universal, however. Many coal plants installed major pollution control technologies in the last 10 years, adding hundreds of millions in new costs to be depreciated over 30 years. If viewed at a systems level, stranded assets may be relatively small, but highly concentrated in particular states and utilities that made these investments, leaving particular groups of customers with high bills to pay.

One strategy for accelerating the retirement of existing assets, while managing rate impacts, is to use securitized or “ratepayer backed” bonds to refinance unrecovered plant investment balances to take advantage of lower-cost capital. When high-cost fossil plants are replaced by lower-cost new renewables, the remaining value of the fossil plant can be recovered immediately by a bond, with the cost of the bond paid off over time by a non-bypassable charge on customers. The combined cost of the new generation plus the charge can be less than the cost of running the existing plant, creating savings for customers.[48]

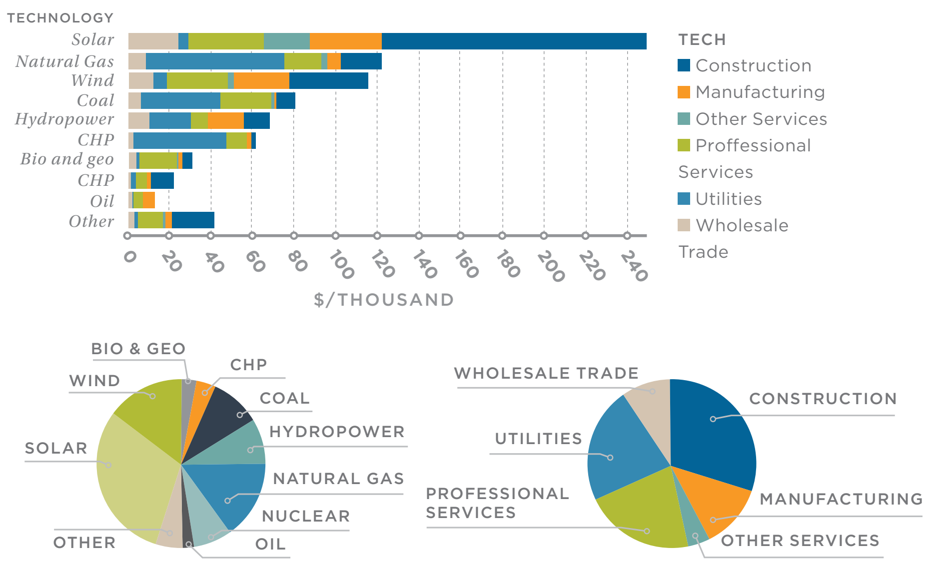
48 Uday Varadarajan, David Posner, and Jeremy Fisher. Sierra Club. Harnessing Financial Tools to Transform the Electric Sector. November 2018.

APPENDIX 4
IMPLICATIONS FOR JOBS, THE ENVIRONMENT, AND PUBLIC HEALTH

JOBS

Such a massive change in the U.S. electricity system will entail significant changes in employment within the sector and along its supply chains. The electric utility sector in America employed 799,742 workers in 2019.[49] About 30% of workers were in construction, with another 20% working for utilities. The solar power sector employed the most workers, almost 250,000 in all, with half of those doing construction and installation. Coal, gas, and nuclear were dominated by utility-sector jobs — such as plant-level operations and maintenance and fuel handling — while wind and solar saw the most construction jobs.

EXISTING ENERGY INDUSTRY JOBS, BY THECHNOLOGY AND SECTOR



JOBS BY SECTOR

Construction	243,989
Manufacturing	100,218
Other Services	166,538
Professional Services	166,538
Utilities	185,478
Wholesale Trade	73,458

JOBS BY TECHNOLOGY

Bio and Geo	21,972
CHP	30,342
Coal	79,711
Hydropower	67,772
Natural gas	121,812
Nuclear	60,916
Oil	12,722
Other	41,417
Solar	248,034
Wind	114,774
Grand Total	**799,472**

Data Source: NASEO 2020

FIGURE 27.

Electric Power Generation Sector — Employment by Detailed Technology Application and Industry, Q2 2019

The fuel supply sector, providing fuels to power generators,

49 National Association of State Energy Officials (NASEO) and the Energy Futures Initiative (EFI). [2020 U.S. Energy and Employment Report]. March 23, 2020.

employed 276,000 in natural gas, 75,000 in coal mining, 33,000 in woody biomass, and 9,400 in nuclear fuels. The “Transmission, Distribution and Storage” sector employed about 1.4 million workers, with the largest share (647,000) working on electricity distribution for utilities and construction companies.

Natural gas distribution employed 238,000, while coal distribution employed 30,000. About 40% of natural gas production in recent years has been sold to the electric power sector, implying that 110,000 fuel-sector jobs are devoted to supplying gas-fired power generation, plus 95,000 in fuel distribution. Combined with the 126,000 workers employed directly in gas power generation, the gas-to-power sector could be said to account for about 321,000 workers.

About 92% of coal sales in 2019 were to the electric power sector, indicating there are another 69,000 fuel-sector jobs devoted to coal power generation and 27,000 in coal shipping. Added to the 79,000 total in coal power generation, the total is 175,000.[50] Coal, however, is seeing significant declines as a power sector fuel, along with significant declines in employment.

Notably, battery storage employed 65,000 workers in 2019. Adding it to “smart grid, micro grid, and other grid modernization” jobs yields almost 133,000 jobs.

Employment Shift

In the move from fossil fuels to renewable energy, the main shift in employment is from operations and maintenance (O&M) jobs, inherent in the operations of coal and gas power plants, to manufacturing and construction jobs, inherent in the task of rebuilding the power system.

While coal and gas plants require a steady stream of fuels that are extracted, shipped, and processed before being burned for power generation, wind and solar plants have their fuels delivered to them at no cost. Free delivered fuel constitutes a significant structural cost advantage over fossil fuels, in addition to the environmental benefits.

Moreover, the lack of fuel handling greatly reduces the number of jobs needed to maintain and operate the generating plant. Wind and solar plants require very little maintenance, since there is no combustion causing extreme temperatures and fouling of the equipment. They also require very little operation work, since movement of solar trackers are computer-controlled to maximize efficiency; fixed-mount solar panels don’t move at all.

50 Fuel sales data from the Energy Information Administration.

Wind, solar, and batteries require more manufacturing than fossil fuels, so with the right set of policies, the transition could support significant industrial job growth. All are relatively small modular technologies, ranging from 200 Watt solar panels up to 10 MW wind generators, which are deployed in great numbers.

Results

To gauge the impact of a shift to a 90% clean power system, Inclusive Economics ran generation and capacity modeling results through IMPLAN, the industry standard software tool for evaluating employment and economic impacts.[51] IMPLAN is an input-output economic model based on the interdependencies between economic sectors, commonly used to estimate the impacts of "shocks" to an economy and to analyze their resulting ripple effects.

The results, as shown in Figure 28, find that the No New Policy case requires 13 million cumulative job-years from now through 2035 for O&M, plus 7.4 million job-years in construction. In the 90% clean case, through 2035, there are 17.9 million job-years in construction and 11 million in O&M, or an annual average of 1.1 million and 690,000 jobs, respectively. The net difference is a gain of about 530,000 jobs per year, or 8.5 million cumulative job-years, in the 90% Clean case.[52]

NO NEW POLICY (NNP) VS. 90% CLEAN-JOBS

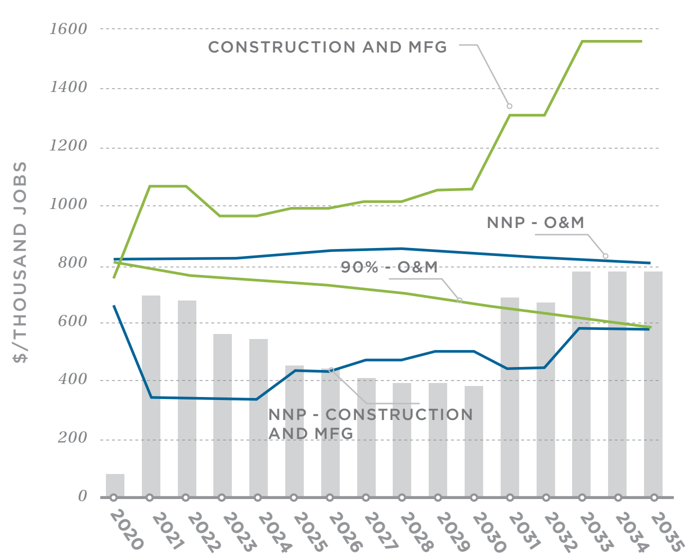


FIGURE 28.

Jobs in Construction and O&M in 90% Clean and No New Policy Cases

51 Inclusive Economics at http://inclusiveecon.com IMPLAN at https://www.implan.com/.

52 A job-year represents one full-time job held for one year.

The baseline No New Policy scenario, which envisions modest gains in renewable energy, sees very little change in O&M or construction jobs. As shown in Figure 29, about 1.3 million workers are needed on average in the No New Policy scenario, with about two-thirds of them in O&M and one-third in the construction chain (including manufacturing, supply chain, and construction, plus induced jobs). In this case, coal and gas O&M is the largest portion of the jobs, averaging approximately 260,000 workers per year, each. Solar still accounts for the largest number of construction jobs, averaging approximately 220,000 jobs even in the No New Policy scenario.

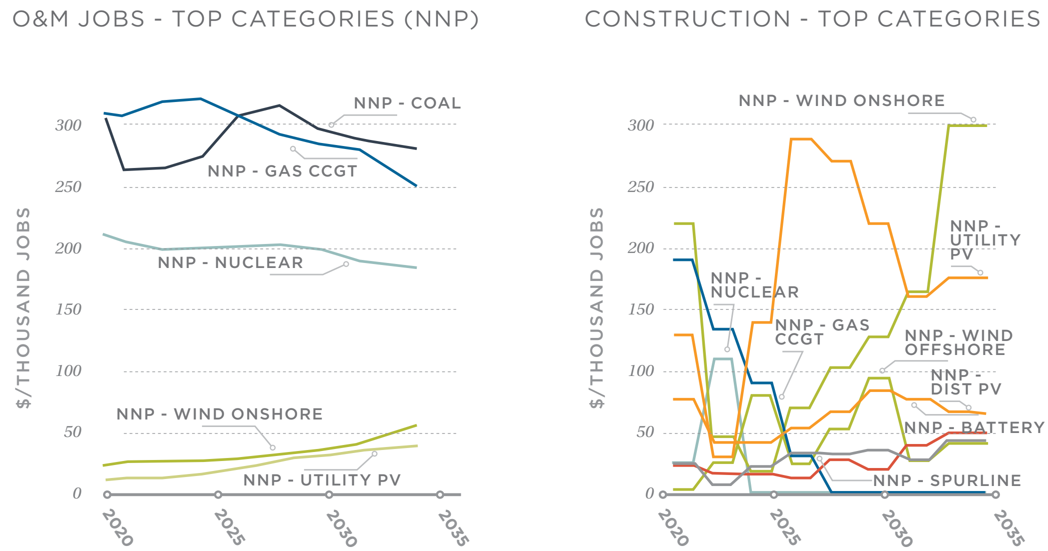


FIGURE 29.

Jobs in O&M and Construction in the No New Policy Case

By contrast, the 90% clean scenario supports far more construction jobs, but fewer O&M jobs, as shown in Figure 30. Construction jobs for solar and wind power boom in the 90% Clean scenario: wind averages 530,000 jobs per year, mostly for onshore projects, while solar sees 350,000, primarily in utility-scale solar. Together, wind and solar jobs account for around 80% of construction employment. The increase in wind and solar construction jobs far exceed the fossil O&M job losses, as coal and natural gas operations phase down and out, shedding 400,000 jobs between 2020 and 2035. The additional wind and solar capacity adds 285,000 O&M jobs by that year.

O&M JOBS - TOP CATEGORIES (90% CLEAN)

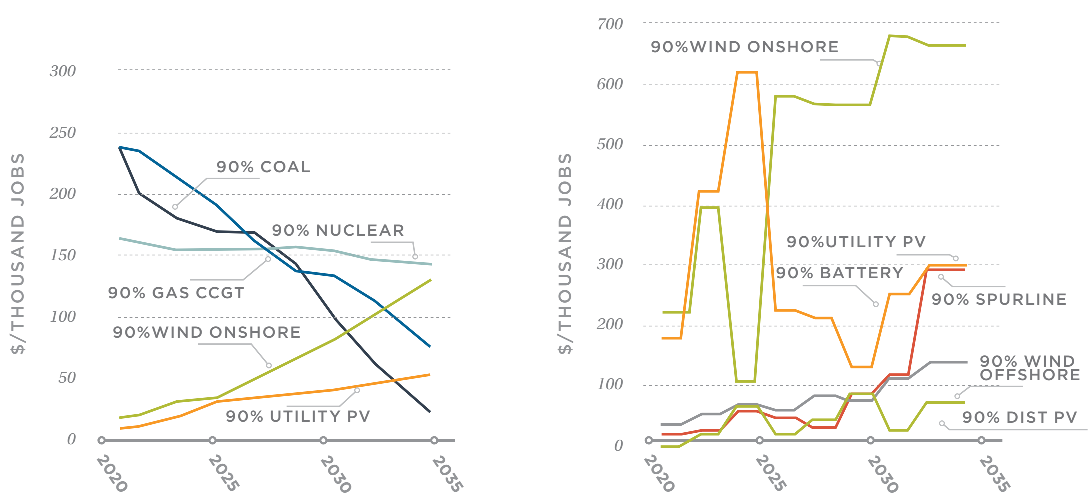


FIGURE 30.

Jobs in O&M and Construction in the 90% Clean Central Case

In short, the 90% Clean case boosts employment over the No New Policy case by an average of 205,000 construction sector jobs, including 90,000 manufacturing jobs, plus 450,000 indirect and induced jobs each year. Onshore wind and utility-scale solar, the largest investment areas, more than make up for jobs lost in fossil fuels. Proposals to use "shovel ready" renewable energy deployment as a post-COVID economic stimulus, similar to the 2009 American Reinvestment and Recovery Act (ARRA), would accelerate the job benefits.

If policies support unionization of utility-scale renewable development, the 90% Clean scenario would create an average of 130,000 unionized construction jobs each year for 16 years, more than double the potential 56,000 jobs in the No New Policy scenario (few of which are unionized under current policy conditions). Currently, union membership in the power generation sector is at 7%, roughly equivalent to the national private sector average of 6.2%. Wind and solar-sector jobs are below that, at 4-6% unionized, while coal and gas jobs are above, at 10-11%. Nuclear has the most heavily unionized power sector workforce, at 12% of all workers.[53]

More details are available from a data explorer at 2035report.com.

53 National Association of State Energy Officials (NASEO) and the Energy Futures Initiative (EFI). *2020 U.S. Energy and Employment Report*. March 23, 2020.

ENVIRONMENT AND PUBLIC HEALTH

While this study focuses chiefly on achieving a 90% clean electricity system, such an energy system would also produce vastly lower “criteria” pollutants, such as sulfur dioxide (SO_2) and nitrogen oxides (NO_x), as well as lower water use and pollution, creating substantial environmental and public health benefits.

Most of these health and environmental benefits come from phasing out coal. Coal power generation accounted for about 90% of the premature deaths related to air pollution and 66% of greenhouse gas emissions associated with the U.S. power sector in 2019.[54] The marginal environmental damage of coal (which our modeling exercise does not include in our main scenarios) is about two times the variable cost of coal. In the Clean 90% case, our modeling retires all coal plants by 2035. See the Retirement section for details on how plants were retired.

CARBON AND CRITERIA POLLUTANTS

Carbon dioxide emissions in the power sector fell from 2,500 million metric tons (Mt) in 2010 to 1,800 Mt in 2018, as demand stayed flat and utilities moved away from coal to natural gas and renewables.

Going forward, the No New Policy scenario in our study sees carbon emissions level out through 2035, with modest demand growth being met by increases in wind and solar generation, but very little change in coal and natural gas generation. In the 90% Clean case, however, carbon emissions fall to about 180 Mt in 2035, as coal phases out and natural gas generation drops to about 10% of total demand.

Criteria pollutants such as SO_2 and NO_x also see large drops in the move away from coal. In 2010, coal accounted for 99% of SO_2 emissions and 96% of NO_x emissions in the power sector. Between 2010 and 2018, SO_2 emissions fell over 50%, from 2.5 Mt to 1.1 Mt per year, driven by a drop in coal generation along with deployment of pollution controls. NO_x emissions likewise fell from 1.9 Mt to 1.0 Mt.

Looking forward, the decline in fossil fuel generation in the 90% Clean case pushes SO_2 and NO_x down to 0.009 Mt and 0.036 Mt in 2035, respectively. The No New Policy case sees steady SO_2 and NO_x emissions of about 0.8-0.9 Mt per year through 2035.

54 Environmental Protection Agency. Sources of Greenhouse Gas Emissions | US EPA. 2018.

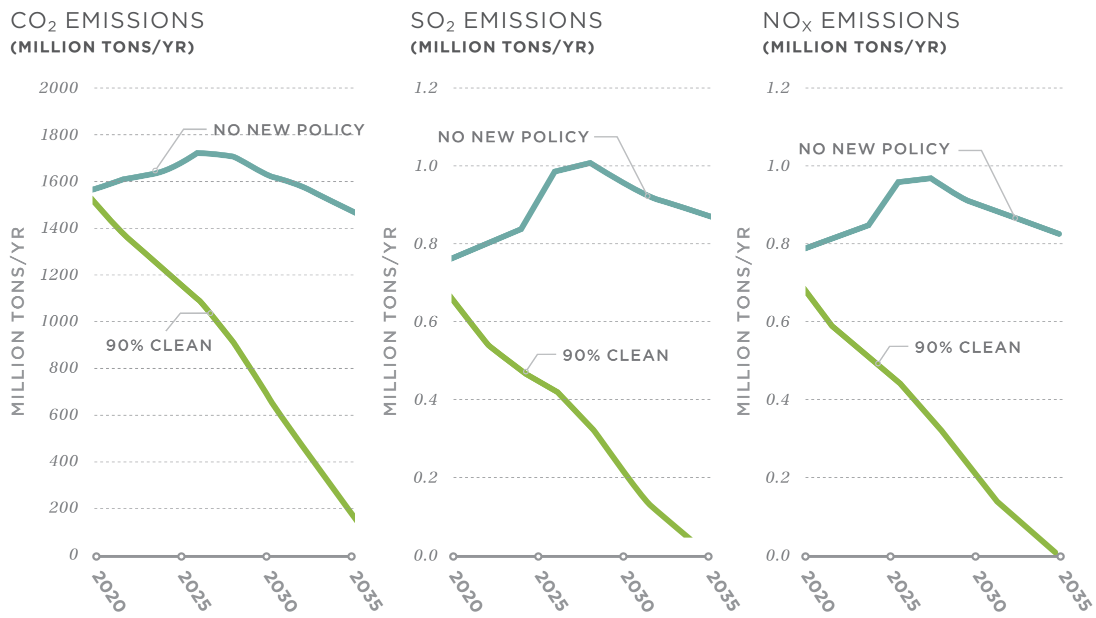


FIGURE 31.

Emissions of CO_2, SO_2, NO_x in the 90% Clean and No New Policy Cases, 2020–2035

DAMAGE COSTS

For many decades, environmental regulations have been promulgated based on the cost-benefit calculations of the regulations. As a result, there is a substantial scientific literature on how to measure the impacts of air pollution on public health and the environment, and to translate those damages to financial terms.

The benefits of reduced greenhouse gas emissions are valued at a social cost of carbon of $10/ton in 2020 increasing to $40/ton by 2023, and from 2024 onward increasing at 1.5% per year reaching up to $50/ton by 2035, derived from Baker et al. (2019)[55] and Ricke et al. (2018).[56] Avoided air pollution damage estimates for SO_2, NO_x, and $PM_{2.5}$ are based on state-by-state premature death factors based on Thind et al. (2019)[57] and the Value of Statistical Life of $9.3 million (2018 real) based on

55 Baker, J.A, H.M. Paulson, M. Feldstein, G.P. Shultz, T. Halstead, T. Stephenson, N.G. Mankiw, and R. Walton. 2019. The Climate Leadership Council Carbon Dividends Plan. Climate Leadership Council.

56 Ricke, K., L. Drouet, K. Caldeira, and M. Tavoni. 2018. Country-Level Social Cost of Carbon. Nature Climate Change 8: 895–900.

57 Thind, M.P.S., C.W. Tessum, I.L. Azevedo, and J.D. Marshall. 2019. Fine Particulate Air Pollution from Electricity Generation in the US: Health Impacts by Race, Income, and Geography. Environmental Science & Technology 53(23): 14010–14019.

Holland et al. (2020).[58] For more details on methodology, see Appendix 2.

We find that in the No New Policy case, environmental costs have a net present value (NPV) of $2.04 trillion between 2020 and 2050, using a real discount rate of 2.75%. The largest portion is the cost of carbon damage ($1.33 trillion). Other air pollution damages total almost $0.71 trillion. The total environmental damage cost of the No New Policy case, if added to the wholesale generation cost, results in an adder of $20-25/MWh to the wholesale generation costs up to 2040, and then reduces to $10/MWh by 2050.

The 90% Clean Case avoids over $1.3 trillion (2018 dollars) in environmental and health costs through 2050, including avoiding around 85,000 premature deaths (approximately 3,500 avoided deaths per year) from 2020-2050. The environmental cost adder reduces to $2/MWh by 2035 and beyond.

Including the environmental costs, wholesale electricity costs in the 90% Clean case are 25% lower than the No New Policy case by 2035.

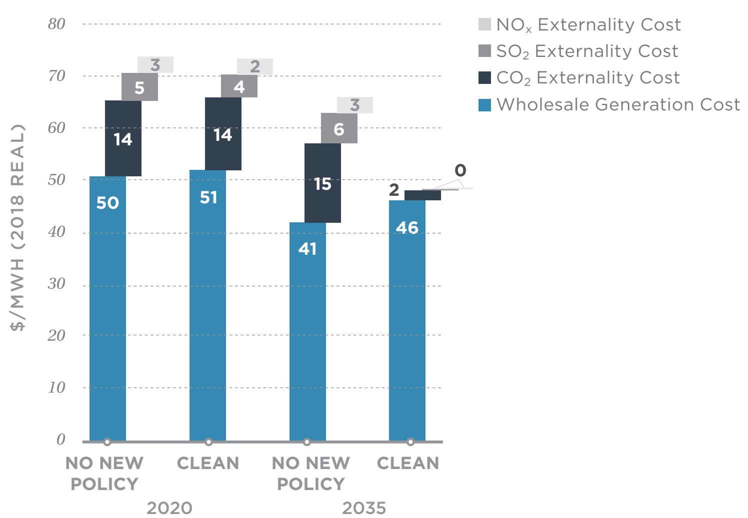


FIGURE 32.

Wholesale Electricity Costs (Including Environmental Costs) in the No New Policy and 90% Clean Cases

58 Holland, S., Erin T. Mansur, Nicholas Z. Muller, Andrew J. Yates, (2020) "Decompositions and Policy Consequences of an Extraordinary Decline in Air Pollution from Electricity Generation", American Economic Journal: Economic Policy, forthcoming in Volume 12, Issue 4, November 2020.

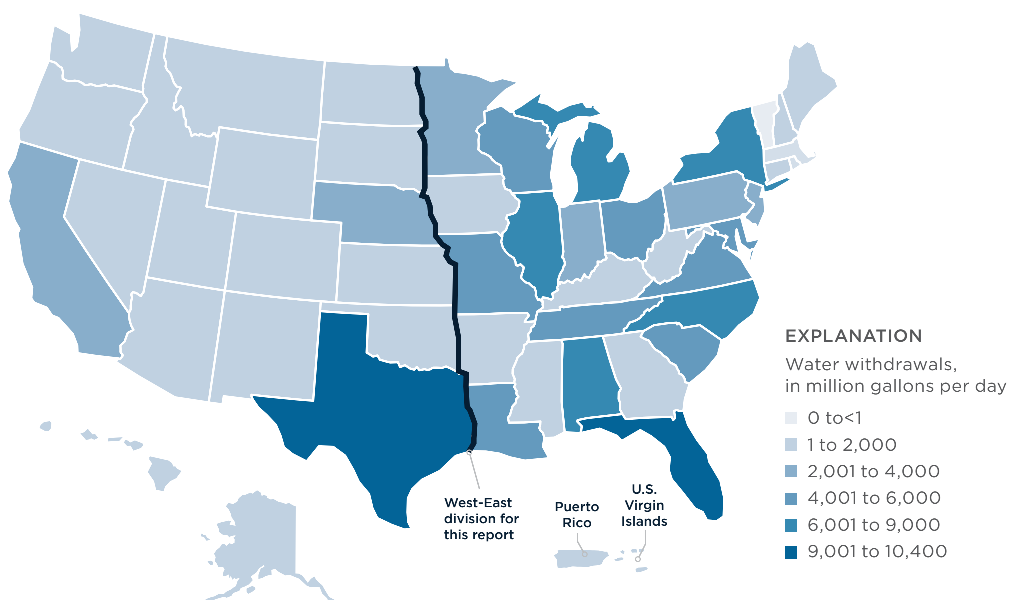
Water Use

Thermal power generation is the largest user of water in the U.S.; only water used for farm irrigation comes close. Vastly lower reliance on thermal power plants would cut water use substantially, reducing the impact of drought on energy production, reducing competition with other water uses (such as irrigation), and lowering environmental impacts.

U.S. power generation in 2016 withdrew 150,000 million gallons per day (mgd) from water sources, largely for steam production and cooling at coal, nuclear, and natural gas combined cycle plants.[59] All but 2,800 mgd withdrawn for thermal power generation in 2016 was returned to the water sources, but at a higher temperature. Power plants are by far the largest source of thermal pollution into waters, affecting aquatic life. Water use was highest in Texas and Florida.[60]

THERMOELECTRIC POWER 2015

TOTAL WITHDRAWALS



Source: USGS, 2015

FIGURE 33.

Thermoelectric Power Water Use

59 Energy Information Administration, Electricity Data Browser, plant-level data.

60 United States Geological Survey. Dieter, C.A. et al. Estimated use of water in the United States in 2015. 2015.

While thermal power plants use different cooling technologies, including air cooling, which can greatly affect water use, we did not have results at that level of detail. We can say, however, that generation from all thermal power plants (coal, gas CCGT, nuclear, and biopower) in the central 90% Clean case falls from 3.3 million GWh in 2016 to 1.1 million GWh in 2035, suggesting a drop in water use of two-thirds, which would save approximately 100,000 mgd. The decline in water demand would be especially important in dry regions of the country, such as Texas and the Western United States.

Land Use

Greater reliance on wind and solar power would greatly increase the land footprint of electricity generation. The central 90% clean scenario envisions 515 GW of ground-mounted solar power,[61] which would occupy approximately 13,200 square kilometers (km^2) of land.[62] While this is substantial, it is comparable to land used by airports, or 35% more than the area devoted to golf courses in the United States (about 8100 km^2), or equal to 6% of the state of Kansas.[63] Solar projects would be distributed around the country, largely in rural areas, providing a new revenue source for landowners. Still, policies should encourage solar siting to achieve "techno–ecological synergies" such as habitat restoration and use of brownfield sites.[64]

The 90% clean scenario also sees an installation of 643 GW of wind generation. While wind turbines need space to operate, to reduce turbulence caused by their neighboring turbines, the space in between is typically still used for farming and grazing.[65] So while wind projects need about 0.3 km^2 per megawatt of space, they only *exclusively* occupy about 10% of the space with service roads and turbine bases. Thus, 643 GW of wind would occupy about 19,000 km^2 of land, sited on 192,000 km^2 of farmland. To put this in perspective, the Southwest Power Pool, which features some of the best wind resources in the country, covers 1.4 million km^2 of territory.

Assuming wind and solar are not sited together, the combined area consumed for all wind and solar capacity is only 0.4% of the area of the continental U.S.

61 The 90% Clean Case builds 515 GW of ground-mounted solar, and 63 GW of distributed PV by 2035.

62 Ong, Sean et. al. Land-Use Requirements for Solar Power Plants in the United States. National Renewable Energy Laboratory. June, 2013.

63 Dave Merrill and Lauren Leatherby, "Here's How America Uses Its Land," Bloomberg, July 31, 2018.

64 Hernandezet al., "Techno–ecological synergies of solar energy for global sustainability," *Nature Sustainability*, July 2019, 2:560–568.

65 Denholm, Paul et. al. Land-Use Requirements of Modern Wind Power Plants in the United States. National Renewable Energy Laboratory. August, 2009.

APPENDIX 5
LIMITATIONS AND AREAS FOR FUTURE WORK

This study does not answer all questions about how to achieve 90% clean generation in the U.S. electric sector, suggesting that future areas of research would further support a rapid, cost-effective clean electricity transition.

This study does not address how to get to a completely zero-emission power system, after achieving 90% carbon free generation in 2035. Technology and market developments in the next 15 years will likely answer that need, such as through new and lower cost and potentially longer duration forms of storage, enhanced demand response and flexible load, hydrogen created from renewables, modular and flexible nuclear generation, carbon capture use and sequestration, and better grid integration practices. The thesis of this research is that getting to a 90% clean energy goal by 2035 is feasible and prudent using technologies that are commercially viable today, and that a complete solution will emerge over time. The policy brief from Energy Innovation discusses research priorities for government funding to support the transition to 100% clean.

We have not addressed the potential for end-use energy efficiency and demand response to help reduce dependence on fossil generation in the near term, using only the AEO 2020 base case, which anticipates only modest gains in each. Each of these factors could be an important contributor to electric sector decarbonization, and would tend to make the 90% clean goal even more achievable by reducing demand and the need for batteries and dispatchable gas generation.

Emissions are counted only at the point of generation, not across the life cycle of the energy source. For example, upstream methane emissions of gas-fired generation are not considered. Reduced gas generation will indirectly reduce upstream methane emissions, which have a greater warming potential than CO_2, so excluding them from this study underestimates the total greenhouse gas benefit of a low-carbon power system.66

This study has significantly different transmission system results than other studies, finding that relatively little new inter-regional transmission is needed to achieve a 90% clean generation goal for the electric sector. It appears that geographically dispersed wind and solar generation, combined with battery energy

66 Ramón A. Alvarez, et al. Assessment of methane emissions from the U.S. oil and gas supply chain. Science. July 13, 2018.

storage and the infrequent use of existing gas generation, is a lower cost strategy than substantial interregional transmission build-out. However, the tools we used (primarily ReEDS), like all tools, have limitations and will struggle to co-optimize transmission and generation expansion. Given the differences with other substantial research, this point may benefit from more detailed analysis.

Due to the complexity of the task in a national study, we did not assess how a 90% Clean generation sector would affect electric distribution system expansion or operations. Nor did we assess (beyond the NREL dGen forecast embedded in ReEDS) how growth of distributed energy resources (DERs) could contribute toward a 90% carbon reduction. Our effort focused primarily on bulk system resources, and further work could help us understand the role of DER in providing both clean generation as well as demand flexibility.

Since this was a national study, analysis on the regional level would provide helpful details to state and regional policymakers. While ReEDS and PLEXOS are location- and time-specific, and use real-world resource and weather data, they necessarily simplify the U.S. power system, and regional results may not have the fidelity to guide state and local policy decisions such as state clean electricity standards, resource planning, and wholesale market designs.

The study included a scenario that assumes electrification of transport and building sectors. This scenario was intended to test the sensitivity of results, but we did not include such electrification in the core scenarios. The results of this scenario showed electrification of these sectors will increase both overall load and power system flexibility. The increased (and changed) load shape appears to reduce the costs of achieving the 90% clean goal. Greater power system flexibility is likely to enable greater decarbonization of the economy, as clean electricity displaces fossil transportation fuels. However, electrification would further test our ability to rapidly scale production and deployment of clean energy technologies and (potentially) associated transmission.

This study does not utilize a fully constrained dispatch model (with balancing and operability). We address this partially through a worst case renewable energy reduction scenario, with an estimate of gas generation needed during extreme weather events (e.g when wind or solar generation is 50% below average during a winter evening peak).

We did not attempt to assess the impact of potential macroeconomic changes to interest rates and capital markets on electric system costs, or any rebound effects of gas prices due to lower demand.