Exhibit 28

LNG and Renewable Power

Risk and Opportunity in a Changing World

PREPARED BY

Jurgen Weiss, PhD

Steven Levine

Yingxia Yang, PhD

Anul Thapa

January 15, 2016

All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group, Inc. or its clients.

Acknowledgement: We acknowledge the valuable contributions of many individuals to this report and to the underlying analysis, including members of The Brattle Group for peer review.

Table of Contents

Executive Summary

Two important trends are transforming the energy industry across the globe. The production of relatively low-cost unconventional sources of natural gas—primarily in the United States and Canada, but potentially also in other parts of the world—has led to much heightened attention to the possibility of increased use of Liquefied Natural Gas ("LNG") in world markets and a large number of proposed LNG export projects in North America. Several LNG export projects are under construction in North America (and will begin exporting in the next few years), and many more are proposed with the hope of being part of a "second wave" of LNG projects to begin service in the post-2020 time frame. At the same time, both technological progress and concerns about climate change risks are stimulating the development and deployment of various types of renewable energy sources around the world.

While the natural gas industry has traditionally viewed LNG as a substitute for oil in many markets, this paper explores whether the evolution of renewable energy sources suggests that LNG may be competing less with oil and more with renewable energy sources in markets outside of North America in the coming years. Such competition is evident in electricity generation markets as natural gas combined-cycle units and renewable energy sources compete to serve future electricity demand. Competition between natural gas and efficient electric heating (using heat pumps, for example) is less prominent, but emerging in some countries (*e.g.,* Germany). Thus, there are important and intensifying linkages between global natural gas and electricity markets that will impact developments in renewables markets and have feedback effects into the natural gas market.

This emphasis on LNG development takes place against a backdrop of several important market dynamics, including the recent collapse in world oil prices, a slow-down in China's economy and its demand for natural gas, the commissioning of new LNG export projects in Australia, and a reduced need for natural gas in Japan due to the re-start of some of the country's nuclear power plants. As a result of these factors, Asian LNG prices, which had risen to \$15/MMBtu (or more) in recent years, have now collapsed to roughly \$6-\$7/MMBtu, and the significant price differential between world oil prices and North American natural gas prices (that gave rise to the North American LNG projects now in development) has now declined dramatically. The deterioration of this price differential is bad news for both the LNG export projects in development (but not under construction) in North America and the energy companies that signed up for long-term LNG export capacity from the new North American export projects (that are under construction and one of which will begin service in early 2016). These market suppliers need LNG delivered prices in Asia to be in the $10-$11 range in order to be profitable. With several more LNG export projects coming online in the 2015-2020 period and an expectation of continued low oil prices, global LNG markets are likely to be oversupplied for the next several years and the low LNG prices now observed seem likely to persist for some time. The fate of many of the proposed North American LNG export projects is increasingly uncertain in the new price environment (and some LNG export projects have already been delayed).

Thus, two important questions facing global LNG markets today are how quickly LNG supplies associated with the new LNG projects coming online over the next few years will be absorbed, and at what point in the future there might be a rebound in global LNG prices such that new LNG export terminals (beyond the terminals now under construction) are needed. The LNG export developers in North America (as well as buyers of LNG from the projects now under construction) are hoping that the worldwide LNG supply glut is temporary and that market conditions in the post-2020 time frame will improve.

The analysis in our paper suggests that market participants should be very cautious in thinking that the LNG supply glut is necessarily a temporary problem, because another important dynamic in world energy markets is the declining cost of renewable power and the prospect of increased penetration of renewables in the global power generation mix and thus competing with LNG as a "fuel source" for power generation. In fact, in some regions such as Germany and California, where renewable penetration has been high, gas demand growth has already been stunted by the penetration of renewables in the generation mix (causing a reduction in gas demand growth for power generation).

There is a real possibility of a significant shift towards more renewable power generation in some of the key Asian markets targeted by the LNG industry. While the current shares of wind, solar, and gas in China are each less than 5% of China's total electricity generation, all three sources of electricity generation are projected to increase substantially over the next 25 years as the share of coal generation as a percentage of total generation is projected to decline significantly from around 75% today to roughly 50% by 2040.[1] Gas, wind, and solar (as well as nuclear) will therefore all be competing to serve China's growing electricity needs. The relative costs of LNG and renewables discussed in this paper will likely be a significant factor determining which technologies achieve the highest penetration levels. Of course, the uncertainties regarding the costs of both renewables and delivered LNG over the coming decades remain significant and other factors not discussed in this paper will influence China's future electricity generation mix. Nonetheless, the expectation of declining costs of renewables (discussed in this paper) relative to LNG is noteworthy and creates the possibility of a potential shift towards even more renewable generation than is currently forecast in key Asian markets.

Since many LNG forecasts suggesting that the LNG supply glut is temporary rely on the assumption that natural gas demand from China and other countries in Asia will more than double in the next 20 years (in part due to gas demand in the power sector), these forecasts should be seen as highly uncertain given the potential for a significant shift towards more renewable power in China and throughout Asia that could limit the growth in gas demand and the need for LNG. Likewise, in Europe, despite the fact that declines in domestic natural gas production (as well as the perpetual desire to diversify away from Russian-sourced natural gas) are leading many to look at LNG as a potential alternative, the on-going shift towards more renewables may reduce the incentive to import significantly larger amounts of LNG.

LNG infrastructure is very capital intensive across the entire LNG supply chain. As a result of the billions of dollars of fixed costs, LNG projects and associated financing arrangements usually require long-term contractual arrangements for the necessary infrastructure. These contractual arrangements allow the developers of the LNG infrastructure to pass the risk of their projects on to their counterparties. For example, the developers of LNG export projects may sell their export capacity to large energy companies (such as BP, BG, Total) who then assume the risk for selling LNG to overseas customers. In other cases, the developers may contract directly with overseas

---

[1] See, for example, World Energy Outlook 2015, p. 634, which forecasts the share of gas-fired generation (as a percent of total electricity generation) in the New Policies Scenario to grow from 2% in 2013 to 8% in 2040. WEO forecasts the share of wind generation to grow from 3% to 10%, and the share of solar PV to grow from 0 to 3% over this time period. Growth in generation from gas, wind, and solar PV over this time period is forecast to be 788 TWh, 886 TWh, and 353 TWh, respectively. Growth in installed capacity from gas, wind, and solar PV over this time period is forecast to be 160 GW, 321 GW, and 258 GW, respectively.

end-users. In either case, the risks can be substantial, especially because how much gas will be needed overseas is uncertain, *e.g.*, for gas-fired electricity generation purposes future needs may not be known with any meaningful precision at the time long-term contracts are signed. LNG project developers will also not be completely shielded from risk for several reasons: the capital recovery period may extend beyond the term of their initial long-term contracts, the capacity of a given LNG project may not be fully subscribed, they will be subject to the ongoing creditworthiness of their counterparties, and they may face demands for contract price adjustments as market conditions and the competitive LNG landscape changes. Thus, market participants along the LNG supply chain need to understand how the development of renewable resources in overseas markets could impact the need for LNG imports in those markets.

Ultimately, investments in North American LNG terminals[2] require that the prices paid for LNG in overseas markets are greater than or equal to the price of U.S. natural gas supplies (*e.g.,* at Henry Hub) plus the cost of all infrastructure necessary to liquefy and deliver LNG to overseas markets (including a fair rate of return on that infrastructure). If the cost of renewable generation is low enough overseas (*i.e.,* below the cost of new gas-fired generation burning LNG from North America), it could dampen the attractiveness of North American-sourced LNG as a fuel for electric generation and the willingness of market participants to continue to contract for LNG export infrastructure.

We find that the competition between renewable power and gas-fired generation using LNG delivered from North America is increasing in overseas markets. Our conclusion is based on an analysis of the costs of developing new gas-fired generation in Asian and European markets that use LNG from North America as a fuel source compared to the costs of developing new renewable generation in those markets. Our estimate of the delivered cost of LNG from North America includes both the forecasted commodity cost of North American gas supplies (from the U.S. Energy Information Administration) and the infrastructure costs of liquefaction, shipping, and regasification necessary for North American gas to be consumed in Asian and European markets.

---

2 While this paper specifically discusses the risks posed by the declining cost of renewable energy to North American LNG developers and their customers, a similar dynamics between renewables and LNG could also broadly apply to other regions.

The delivered cost of LNG is shown as the gray and blue shaded areas of the chart in Figure ES-1 below. To compare the delivered LNG cost to the cost of renewable generation, we calculate the equivalent gas price (shown as lines) at which new gas-fired power generation would have the same levelized cost as new renewable generation (assuming regional costs and at various assumed capacity factors).[3] As can be seen in Figure ES-1, in China this comparison suggests that wind generation with a capacity factor of 25% (the yellow line in Figure ES-1) would already be competitive with power generation using LNG delivered from North America at a delivered cost to China of roughly $11/MMBtu (reflecting full recovery of LNG infrastructure costs and a U.S. gas commodity cost of approximately $3.00/MMBtu). Moreover, our analysis shows a risk that wind power in China with capacity factors as low as 20% may become competitive with combined-cycle generation using North American LNG within the next 5 years (at which point delivered LNG prices are forecast to exceed $13/MMBtu).

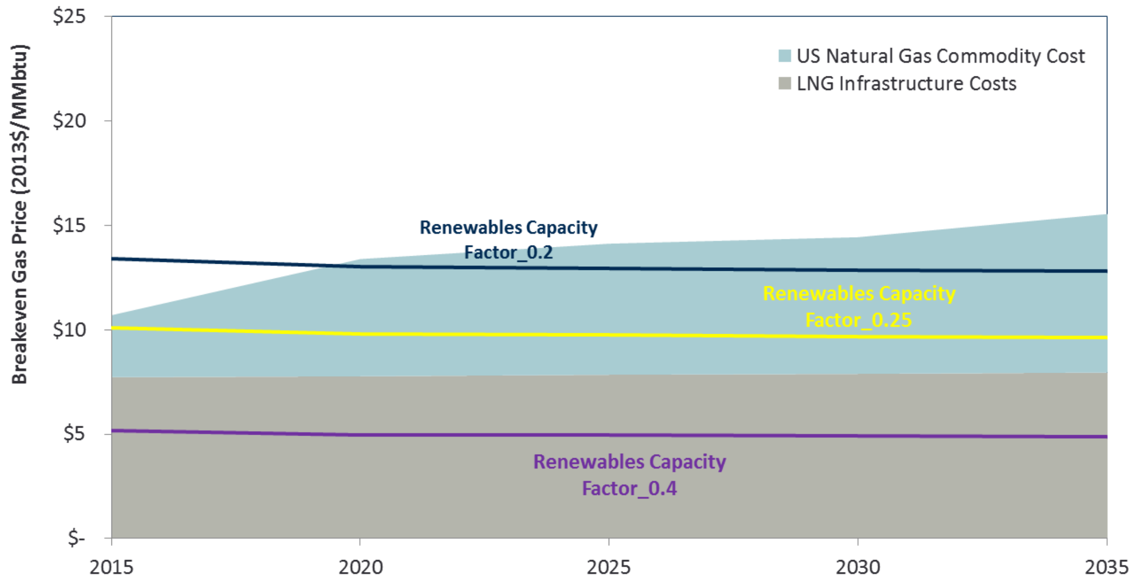
These are important findings, especially with respect to the many proposed LNG export projects in North America (in the U.S. Gulf Coast, Alaska, and Canada) that are still in the early development phase. The investment risk of these proposed LNG export projects is increasing because there is a significant possibility that, over the 20 years of a typical LNG contract, power production from renewable energy sources will become less costly than the LNG sales prices needed to justify the upstream LNG investment cost (even without considering the value of avoided greenhouse gas emissions).

While LNG looks more favorable when compared to stand-alone solar PV and wind in Germany, which, due to its emphasis on renewable energy, we use as an example for potential LNG exports to Europe, a mix (hybrid) of wind and solar and/or a strengthening carbon price could equally lead to renewables becoming less expensive than combined-cycle generation using North American LNG in the coming years, as shown in Figure ES-2.

---

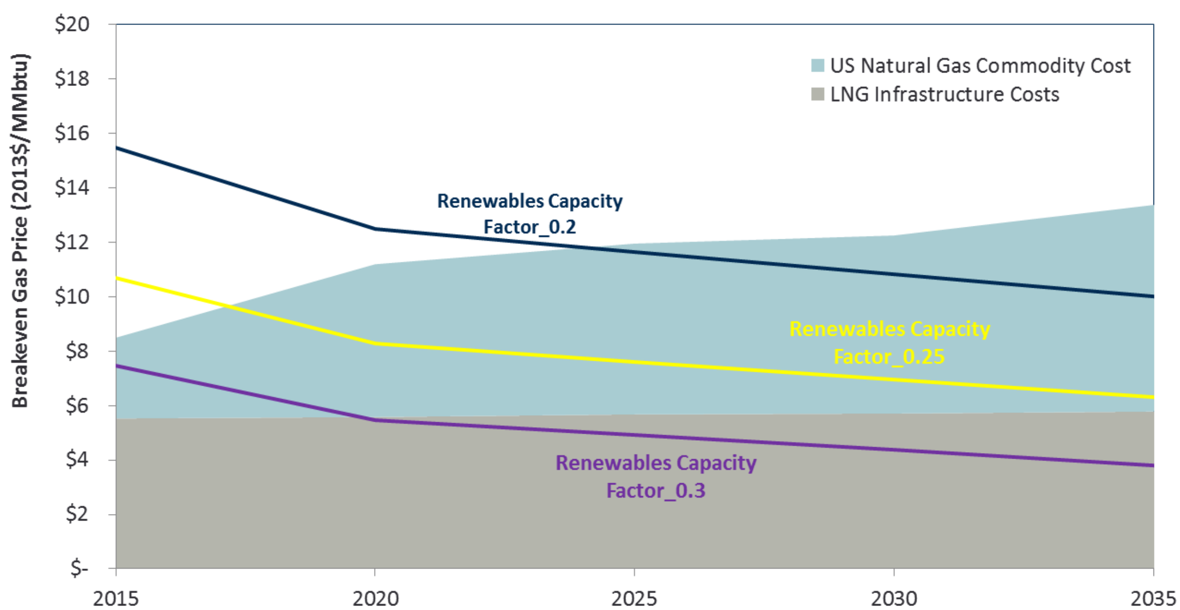
[3] First, we calculate the levelized cost of electricity (LCOE) for renewables in $/MWh using assumed capital costs, fixed operations and maintenance (FOM) costs and renewable capacity factors. We then transform this LCOE in $/MWh into an equivalent gas price in $/MMBtu by calculating the natural gas price that makes the LCOE (in $/MWh) of a new combined cycle gas plant equal to the calculated LCOE for renewables in $/MWh (using assumed capital costs, FOM, VOM, and heat rate of a new gas-fired combined cycle power plant).

Figure ES-1:
Wind costs (in $/MMBtu) compared to the cost of New Gas-Fired Combined Cycle in China Based on Forecast Delivered Cost of LNG from U.S. to China



Sources/Notes: World Energy Outlook 2013 for renewables cost assumptions (NPS Scenario). Delivered LNG cost breakdown from Figure 7 in main report.

Figure ES-2:
The economics of a hybrid wind-solar plant and LNG-fueled power generation in Germany with carbon emissions' cost of $30/ton Based on Forecast Delivered Cost of LNG from U.S. to Europe



Sources/Notes: World Energy Outlook 2013 for renewables cost assumptions (NPS Scenario). Using forecast of delivered cost of U.S. LNG to Europe from Figure 8 in main report.

Of course, this simple analysis does not account for all costs that affect the economic attractiveness of using imported LNG or renewable power. For example, we exclude electricity transmission and distribution infrastructure costs as well as other so-called "renewable integration costs" from our analysis, even though they may be significant at higher levels of renewable penetration and hence could make them less attractive compared to LNG. On the other hand, carbon pricing could become important in LNG export markets other than Europe and tip the scale further in favor of renewables. Also, the cost-overrun and delay risks associated with the massive infrastructure investments needed to export LNG are potentially significant.

Developing a deeper understanding of the relationship between the cost of LNG-fueled gas-fired and renewable power generation is therefore critically important in assessing the outlook for both renewable power and the potential demand for LNG and associated infrastructure. The competition between LNG-fueled gas-fired generation and renewable resources represents a risk to participants in the LNG industry in that higher than expected renewables penetration could reduce future natural gas demand growth (and LNG demand growth) in some of the key overseas Pacific Asian markets. Of course, the reverse is also true: lower renewables penetration in countries planning to develop substantial renewable resources could potentially lead to higher than expected gas demand and LNG growth. While many other factors could impact the demand for LNG in overseas markets (such as the future of nuclear generation, overall load and population growth, potential competition from pipeline imports, etc.), this paper focuses on the specific relationship between the cost of gas-fired generation using LNG and renewables.

The increasing competition between renewable power and gas-fired generation using LNG should be considered carefully by participants in the global LNG markets. This competition increases the uncertainty in global gas demand and the future LNG requirements in markets now being targeted by North American LNG export developers. Both investors in LNG infrastructure and buyers of LNG under long-term contracts will want to consider these risks before making large and long-term commitments to buying or selling LNG.

I. Introduction

The development of unconventional natural gas resources primarily in North America and the relative abundance of natural gas in other parts of the world including Australia and the Middle East have triggered a fundamental rethinking of the future global energy system and the role of Liquefied Natural Gas ("LNG"). While these regions, and particularly the United States and Canada, are hopeful for an energy future characterized by low energy costs as a result of these abundant natural gas supplies, much of the rest of the world faces relatively higher natural gas prices and pressures to move away from coal as a major source of energy, and has few low cost alternatives.

Not surprisingly, the abundance of shale gas in North America, expectations that the cost of these shale resources will remain relatively low, and corresponding expectations of relatively high natural gas prices in much of the rest of the world have led to a wave of proposed large-scale infrastructure projects designed to profit from the apparent arbitrage opportunities. These LNG export projects will allow low-cost American natural gas to be transported and resold into markets with high natural gas prices. North American LNG exports will therefore increase the LNG export-related activity already strong in the Middle East and expanding in Australia.

At present, over 40 LNG export projects representing over 50 Bcf/d of export capacity (or roughly 70% of U.S. gas demand) are proposed in the United States, and over 20 projects representing around 31-47 Bcf/d of capacity are proposed in Canada. As of the end of 2015, 10 LNG terminals have received U.S. Department of Energy ("DOE") approval to export approximately 14 Bcf/d of LNG to non-Free Trade Agreement ("non-FTA") countries, and five of these are now under construction.[4] Since LNG infrastructure is extremely capital intensive, its construction rationale relies significantly on assumptions that gas prices in the North America will remain relatively low and gas and oil prices (and gas demand) in the rest of the world will remain relatively high. Such assumptions are typically justified based on a combination of factors, including expectations

[4] The terminals under construction include Sabine Pass LNG (2.76 Bcf/d), Cameron LNG (1.7 Bcf/d), Freeport LNG (1.8 Bcf/d), Cove Point LNG (0.82 Bcf/d), and Corpus Christi LNG (2.14 Bcf/d). See North American LNG Import / Export Terminal: Approved, FERC, as of October 20, 2015 available at: http://www.ferc.gov/industries/gas/indus-act/lng/lng-approved.pdf.

of the continued availability of low-cost U.S. shale supplies, growing demand for natural gas in relatively fossil-resource-poor parts of the world, on-going gas-on-oil competition, and the difficulty and/or high cost of opening up these markets to gas supplies other than through LNG (*i.e.,* through pipeline imports).

Perhaps the key factor driving these LNG export project proposals was the expectation that the substantial divergence between North American gas prices and world oil prices that existed until recently (shown in Figure 1) would persist over the long-term. Since natural gas imports in many areas (especially in Asian Pacific markets) are priced based on oil market linkages, North American LNG export developers have been selling LNG export capacity—and hope to sell additional export capacity—to market participants that could capture this gas-oil spread by exporting LNG overseas and obtaining an-oil linked price.

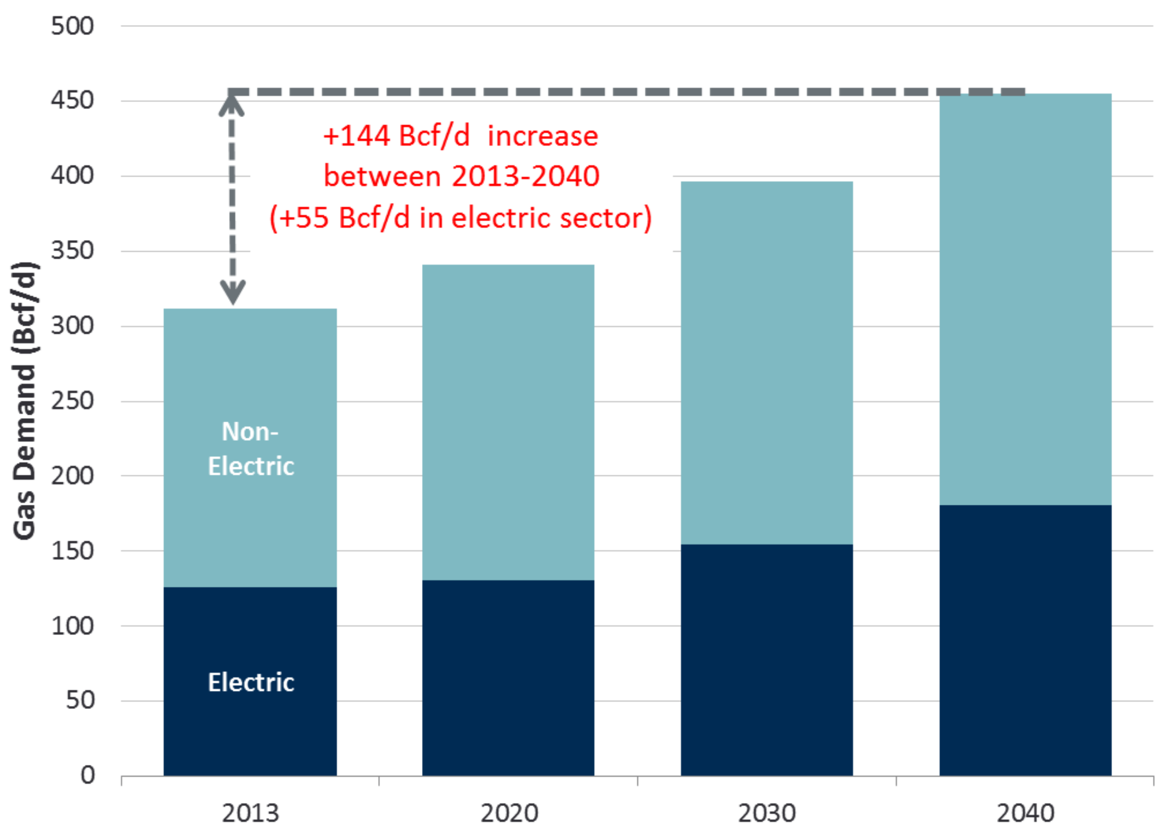
Figure 1
NYMEX Prompt Month Prices
Brent Crude Oil vs. Henry Hub Natural Gas
January 2000 – November 2015

Sources/Notes:

NYMEX data downloaded from EIA and Bloomberg. The natural gas line shows the prompt month Henry Hub prices. The crude oil line shows the prompt month Brent oil prices.

Another factor driving the development of LNG export infrastructure is the expectation of growing natural gas demand in overseas locations without substantial indigenous gas supplies, and therefore the need to import gas supplies either by pipeline from nearby countries or in the form of LNG. Worldwide gas demand forecasts show substantial growth over the next 20-25 years. For example, the International Energy Agency ("IEA") forecasts worldwide gas demand growth of 144 Bcf/d through 2040, of which 55 Bcf/d (38%) is electric sector gas demand (see Figure 2). IEA projects gas demand growth in India and China of 45 Bcf/d of which 20 Bcf/d (44%) is electric sector gas demand. Much of the projected non-electric gas demand and its increase over time are attributed to space heating.

Figure 2
Global Natural Gas Demand
Electric Vs. Non-Electric Sector



Sources/Notes:
IEA World Energy Outlook 2015, Reference Case (New Policies Scenario).

However, will a significant gas-oil price spread really persist and will these gas demand growth projections really come to fruition? There are clearly many uncertainties associated with these expectations, as demonstrated by recent changes in world oil markets that have substantially reduced the oil-gas price spread. In fact, the steep oil price declines beginning in the second half of 2014 (see Figure 1) and persisting today are already leading to concerns about the economic attractiveness of Asian imports of North American LNG and the viability of proposed North

American LNG export projects with Henry-Hub linked pricing.[5] Alternatively, shale gas production in the U.S. could prove to be more costly than now expected, and similarly lead to a narrowing of this spread. LNG export capability growth could exceed LNG demand (perhaps as importers lean more heavily on pipeline imports), and such an LNG supply overhang could make it difficult to achieve oil-linked LNG prices. A worldwide move to more nuclear generation, technological change (even though appearing relatively unlikely at present), enabling the development of coal generation with carbon sequestration, a shift from gas to electricity for the heating sector and, last but not least, more rapid deployment of renewable energy resources, could limit the need for natural gas.

In this paper, we focus on this last issue, namely on the relative costs of LNG (originating in the U.S.) and renewables as one important factor impacting future LNG import demand. We explore the issue by asking a very simple question: **How high does the sale price of LNG have to be to justify investing in LNG infrastructure, and how much competition from renewables might exist for LNG at that price level?** Typically, LNG suppliers think of pricing their product (the LNG they plan to sell) based on gas-on-oil or gas-on-gas competition. We suggest an alternative view on the pricing options and constraints for LNG, namely gas-on-renewables competition. Recognizing that, as illustrated above, a significant portion of the expected growth of natural gas and hence LNG demand over the coming decades is tied to increasing amounts of electricity production, we analyze how vulnerable investments in LNG infrastructure or holdings of long-term LNG export capacity may be to increasing competition from renewable energy sources also capable of meeting future electricity demand.

For the purposes of this paper, we ignore the possibility of producing incremental electricity from oil, coal, or nuclear – all real possibilities in various parts of the globe – and focus on renewable energy sources, which have seen a trend towards declining costs and hence could increasingly challenge natural-gas fired power generation depending on the costs of gas-fired generation in the future, of which the LNG price is an important driver.

5 See, for example, "Weak oil threatens US export of LNG, leaving Asian buyers stranded," Reuters, October 21, 2014. See also "Moody's: Liquefied natural gas projects nixed amid lower oil prices," Moody's Investors Service, April 7, 2015.

If renewable energy production were to become significantly cheaper than making electricity from LNG, this would raise some important questions about: a) the risks of buying LNG or LNG export capacity rights under long-term contracts to meet increasing electricity demand, b) the risk profile of LNG contracts with various forms of price review and adjustment clauses, and c) the economic rationale for investments in LNG infrastructure by both equity investors and lenders.

The remainder of this report explores these questions using a straightforward framework. In the next section, we briefly summarize our basic assumptions concerning the likely cost of LNG infrastructure. In Section III we do the same for various types of renewable energy. In Section IV, we compare the resulting costs of LNG-based and renewable power generation. In Section V, we discuss the implications of our results. In Section VI, we discuss how electric market uncertainties and gas market competition are impacting LNG markets, and in Section VII we draw some conclusions and look forward.

II. The Cost of LNG Infrastructure

The price paid for LNG by an LNG importer differs by region and source of the LNG imported (and by contract vintage, as discussed below). Figure 3 below shows the average estimated landed LNG prices for October 2015 across several countries along with the Henry Hub price in the U.S. As can be seen, at roughly $7.25/MMBtu[6] Asian LNG prices are among the highest in the world. European prices are slightly lower (around $6.40/MMBtu[7]), but still significantly higher than prices in the U.S. The prices shown in Figure 3 are much lower than the prices that prevailed prior to the recent collapse in oil prices. For example, in November 2013, Asian LNG prices were around $15-$16/MMBtu, while European prices were $10-$11/MMBtu and U.S. prices were a little more than $3.00/MMBtu.[8]

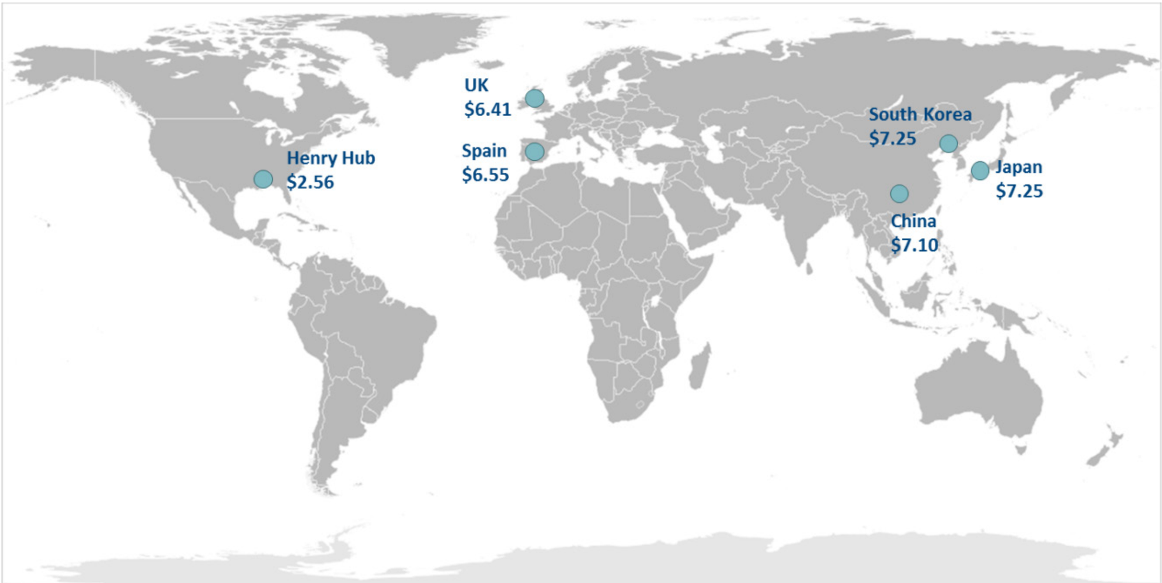
---

6 Federal Energy Regulatory Commission, National Natural Gas Market Overview (updated October 2015) available at http://www.ferc.gov/market-oversight/mkt-gas/overview/ngas-ovr-lng-wld-pr-est.pdf.

7 Id.

8 See http://ferc.gov/market-oversight/mkt-gas/overview/2013/10-2013-ngas-ovr-archive.pdf.

Figure 3
October 2015 Landed LNG Prices for Select Countries
$/MMBtu



Sources/Notes:

Henry Hub prices are from Platts. Estimated LNG landed prices are from the Federal Energy Regulatory Commission, National Natural Gas Market Overview (updated October 2015) available at http://www.ferc.gov/market-oversight/mkt-gas/overview/ngas-ovr-lng-wld-pr-est.pdf.

Note that the LNG prices shown above might be quite different from the delivered cost of LNG which represents the costs (including an appropriate rate of return) of the infrastructure required across the LNG value chain. The prices shown in Figure 3 represent the average landed price of LNG, and large variations may exist between the price of imported LNG based on various factors such as country of origin, whether LNG was imported on a spot or contractual basis, when the contract was signed, etc.

Furthermore, while world LNG trading is much more complex, we simplify our analysis in this paper by assessing the delivered LNG costs for a limited set of origin/destination markets. Specifically, we limit our analysis to the delivered cost of LNG from the U.S. to Asia (China) and Europe, even though similar analyses could be performed for other potential LNG export and import markets. Our two examples thus serve as case studies of a sort, with likely implications for other origin-destination pairs.

We derive the delivered costs of LNG by adding up the costs across the LNG value chain. They consist of: a) the commodity cost of gas at the source, b) the cost of liquefaction at the facility (converting natural gas to super cooled liquid form), c) the cost of shipping from the origin country to the destination country, and d) the cost of regasification (converting LNG to natural gas) and storage at the destination country along with the cost of pipeline transportation from the regasification facilities to the natural gas consumers (*e.g.*, electric generators). The value chain is shown in Figure 4.

Figure 4
LNG Value Chain

For our analysis, we use information contained in a NERA Economic Consulting ("NERA") study evaluating the economic impacts of U.S. LNG exports[9] as the basis for the cost estimates across each step in the value chain (excluding the commodity cost of gas). This study (referred to as the "NERA LNG report") provides forecasts for liquefaction and regasification costs in five year increments between 2015 and 2035. The NERA LNG report also provides point estimates for shipping and downstream pipeline costs, which we keep constant in real-value terms during the forecast period. All of these costs, which are provided in real 2010 dollars ($2010) in the NERA LNG report, are converted to real 2013 dollars ($2013) using GDP deflator forecasts from EIA's Annual Energy Outlook 2015 ("EIA AEO 2015").[10] Together these cost components, including liquefaction, shipping, re-gasification, and downstream pipeline costs, make up the infrastructure

9 "Macroeconomic Impacts of LNG Exports from the United States," NERA, December 3, 2012.

10 "Annual Energy Outlook 2015", EIA, April 14, 2015, available at: http://www.eia.gov/forecasts/aeo/.

costs. The infrastructure cost breakdown for delivered LNG from the U.S. to China/India and Europe for two representative years, 2015 and 2035, is provided in Figure 5 below.[11]

Figure 5
Breakdown of Infrastructure Related Delivered LNG Costs from U.S. to Asia and Europe
2015 & 2035
($2013/MMBtu)

		2015		2035	
		China/India	Europe	China/India	Europe
Liquefaction Costs	[1]	2.26	2.26	2.47	2.47
Shipping Costs	[2]	2.96	1.34	2.96	1.34
Regas and Downstream Pipeline Costs	[3]	2.51	1.93	2.52	1.97
Total Infrastructure-Related Costs	[4]	7.73	5.53	7.95	5.78

Sources/Notes:

"Macroeconomic Impacts of LNG Exports from the United States," NERA, December 3, 2012. The costs were converted to real 2013 dollars using the GDP deflator forecasts from EIA AEO 2015.

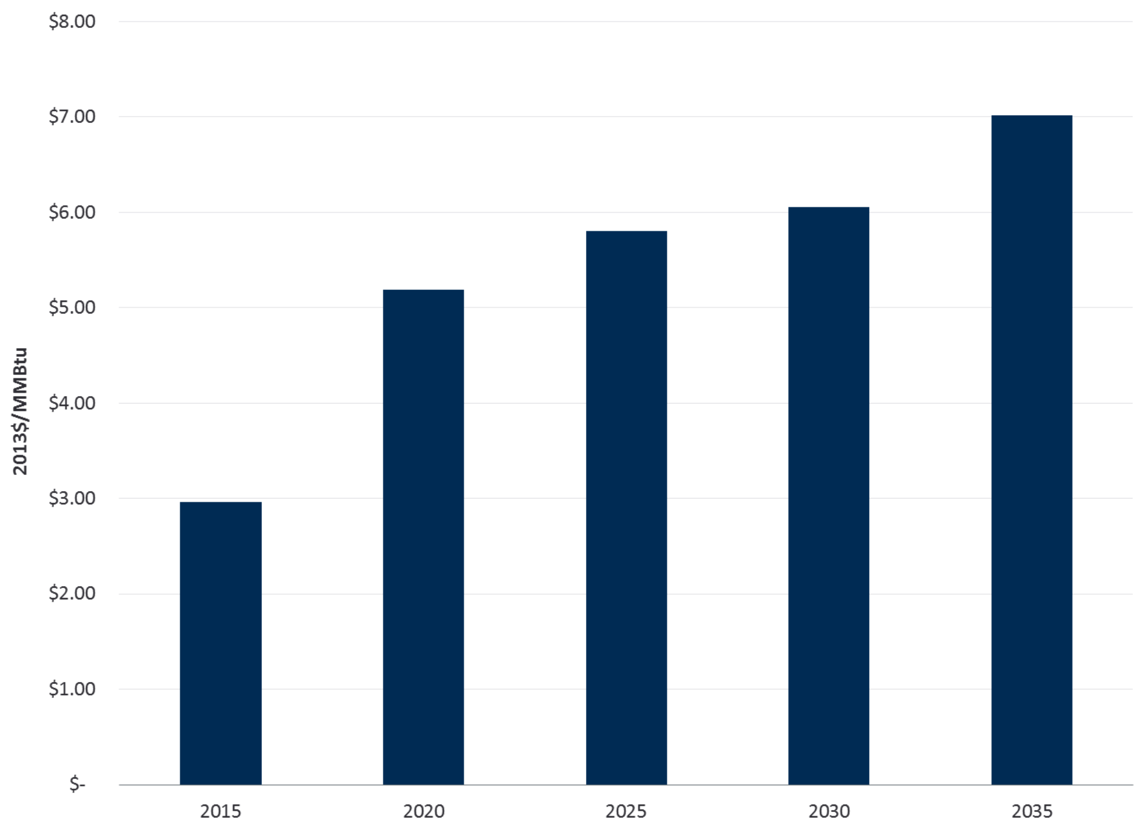
For the cost of feed gas (*i.e.,* the commodity cost of gas) in the U.S., we use the Henry Hub gas price with a 15% adder.[12] The 2015 Henry Hub gas price was obtained from EIA's December 8, 2015 Short Term Energy Outlook (STEO).[13] Henry Hub gas price projections thereafter (2020-2035) are from EIA AEO 2015. The Henry Hub price forecast (in $2013), inclusive of the 15% adder, is shown below in Figure 6.

11 Several of the LNG sales contracts for projects in the U.S. Gulf Coast have LNG pricing structures with a fixed liquefaction fee of around $2.25/MMBtu-$3.50/MMBtu (see, for example, slides 28 and 32 of the Cheniere Energy, Inc. presentation at the December 9, 2015 Capital One Securities Energy Conference). Thus, the forecasted liquefaction costs provided in the NERA LNG report (and reproduced in Figure 5) appear to be towards the lower end of the spectrum.

12 The 15% adder is based on several of the Gulf Coast LNG sales contracts, in which the LNG sales price includes a fixed liquefaction fee plus a variable commodity-based charge of 115% of the Henry Hub natural gas price.

13 The 2015 Henry Hub price reported in the STEO is comprised of historical monthly spot prices between January 2015 and November 2015 and a projected price for December 2015.

Figure 6
115% of Henry Hub Price Forecast
(2015 – 2035)

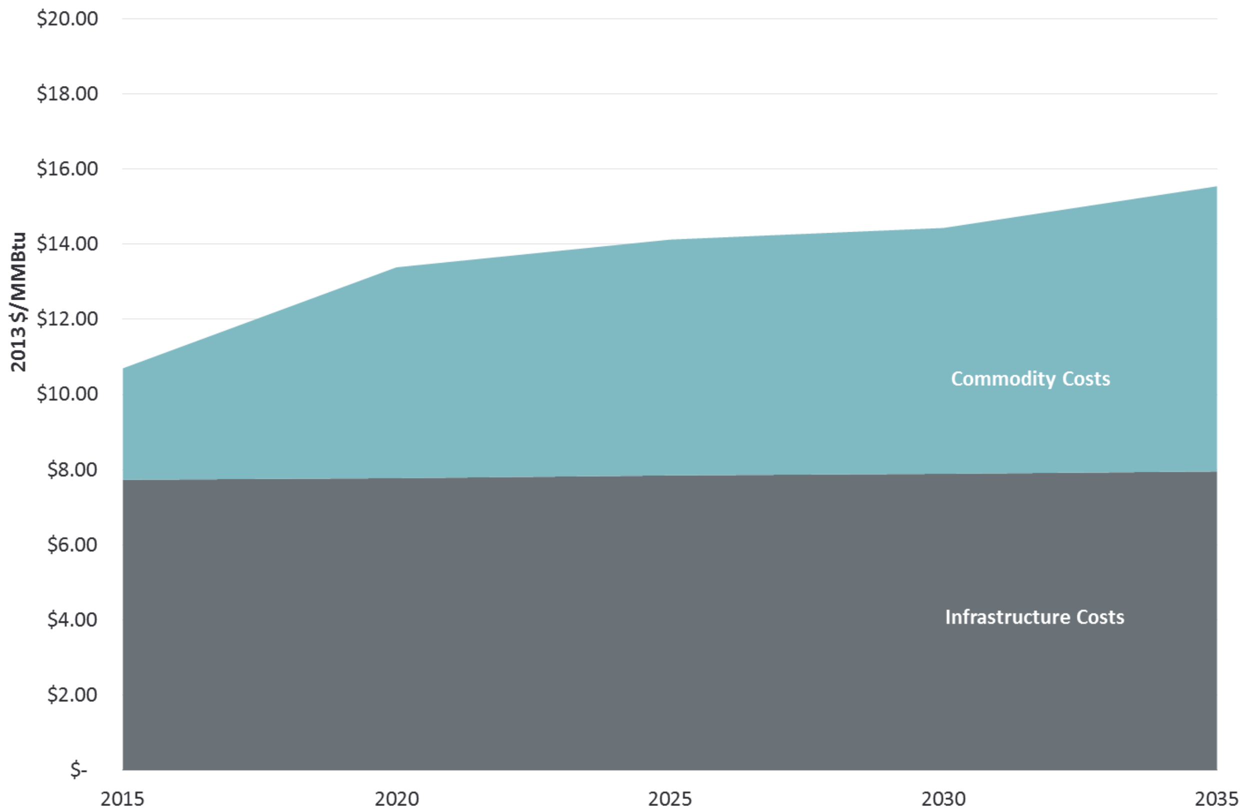


Sources/Notes:

2015 Henry Hub price from EIA Dec 8, 2015 STEO. 2020-2035 Henry Hub prices from EIA AEO 2015.

The delivered cost of LNG is the sum of the commodity cost of gas (shown in Figure 6) and the appropriate destination dependent infrastructure costs (shown in Figure 5). For example, the estimated delivered cost of LNG from the U.S. to China (in 2015) is $10.70/MMBtu ($2013) which is comprised of $2.97/MMBtu ($2013) of commodity cost and $7.73/MMBtu ($2013) of infrastructure-related costs. Figure 7 and Figure 8 show the breakdown of the forecasted cost of U.S. LNG delivered to China and Europe, respectively, between 2015 and 2035. Our analysis of the delivered cost of US LNG assumes that certain components of the LNG infrastructure costs (upstream pipeline, shipping, and downstream pipeline) remain constant in real terms between 2015 and 2035.

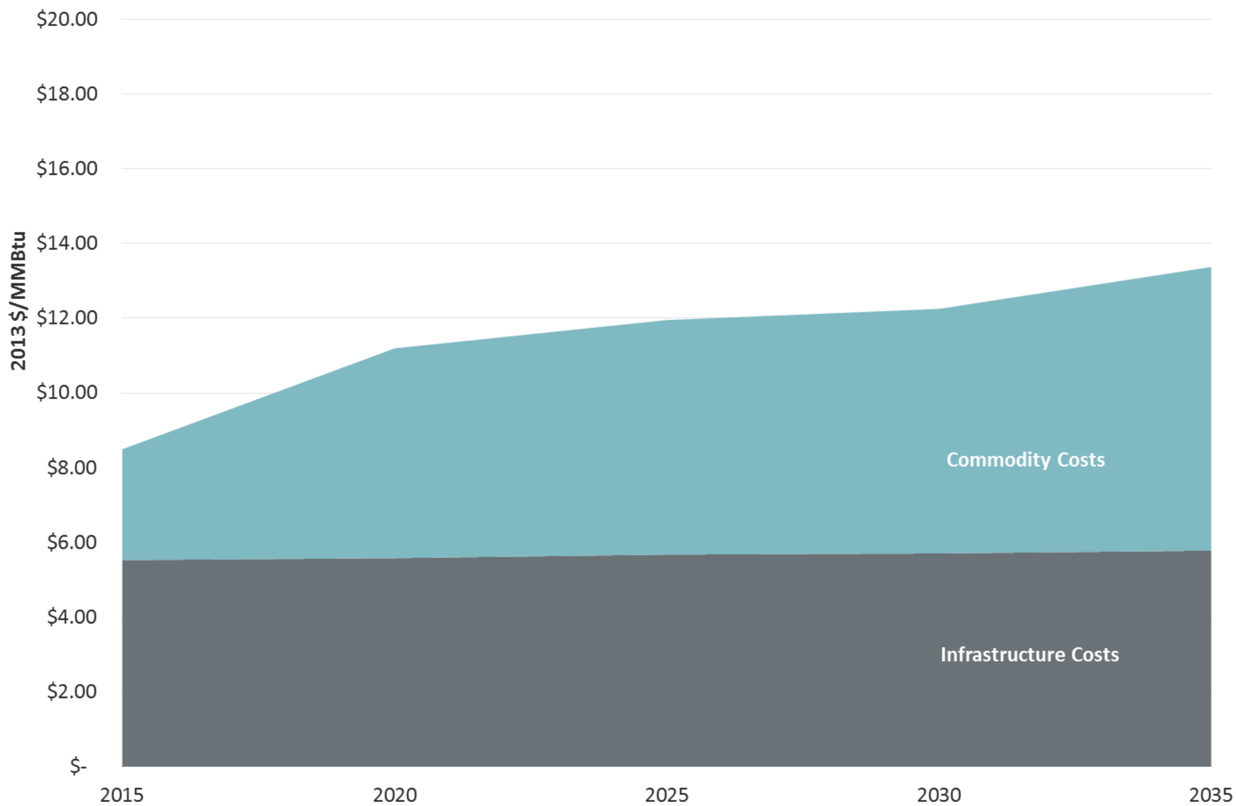
Figure 7
LNG Delivered Cost Breakdown
U.S. to China
($2013/MMBtu)



Sources/Notes:

2015 commodity cost based on 2015 Henry Hub price reported in EIA December 8, 2015 STEO. 2020 – 2035 commodity costs based on Henry Hub forecast from EIA AEO 2015. Data for other LNG costs components from the NERA LNG Report. The LNG cost forecasts are converted to real 2013 dollars using GDP deflator forecasts from EIA AEO 2015.

Figure 8
LNG Delivered Cost Breakdown
U.S. to Europe
($2013/MMBtu)



Sources/Notes:

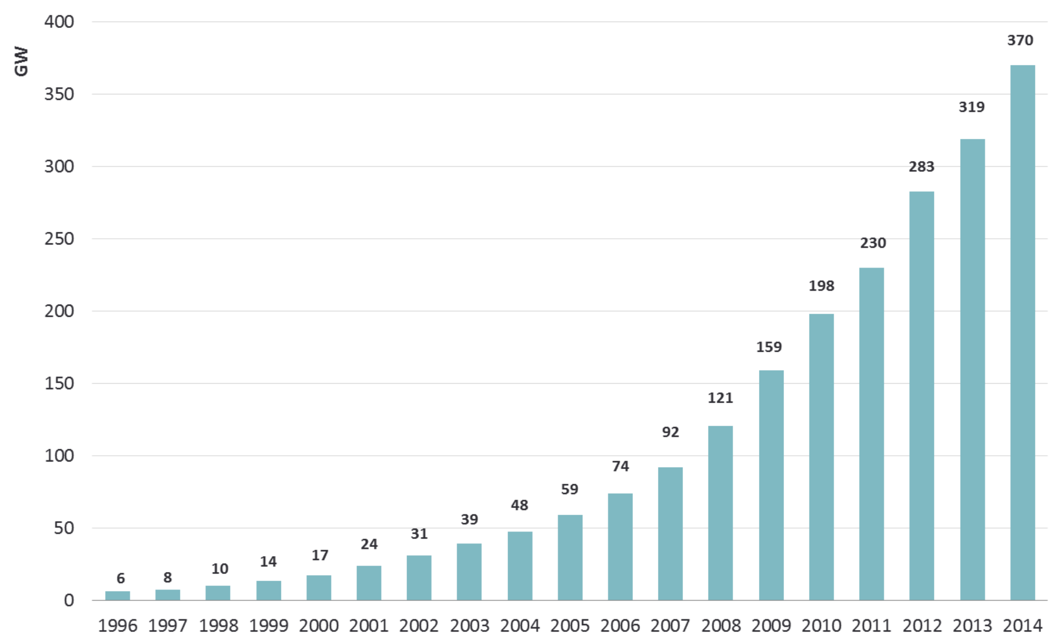
2015 commodity cost based on 2015 Henry Hub price reported in EIA December 8, 2015 STEO. 2020 – 2035 commodity costs based on Henry Hub forecast from EIA AEO 2015. Data for other LNG costs components from the NERA LNG Report. The LNG costs forecasts are converted to real 2013 dollars using GDP deflator forecasts from EIA AEO 2015.

The costs of LNG throughout the value chain are both highly location specific and subject to considerable uncertainty, as exemplified by the construction cost of liquefaction facilities, which can be subject to cost inflation and cost over-runs. These cost uncertainties can have a significant impact on the economic risk of LNG infrastructure. While we do not focus on these risks in this paper, we address potential implications of these cost uncertainties in our conclusions.

III. The Cost of Renewable Power Generation

Another important change in world energy markets is the continued evolution of renewable sources of power generation. Over the past decade the world has witnessed rapid growth in installed renewable electric generation capacity, dominated by wind and solar technologies. As shown in Figure 9, total installed global wind capacity increased from about 6 GW in 1996 to 370 GW in 2014 (an average annual growth rate of 26%). 51 GW was added in 2014 alone. This increase has occurred mostly in Asia (mostly China), North America, and Europe.[14] Likewise, solar power generation has experienced substantial growth. As shown in Figure 10, total installed global PV capacity increased from 1.4 GW in 2000 to 177 GW in 2014 (an average annual growth rate of 41%). 40 GW was added globally in 2014, with growth mainly occurring in China, Japan and the U.S. while Germany was the major source of growth in the early years and still has the largest cumulatively installed capacity.[15]

Figure 9
Global Cumulative Installed Wind Capacity
1996-2014



Sources/Notes:

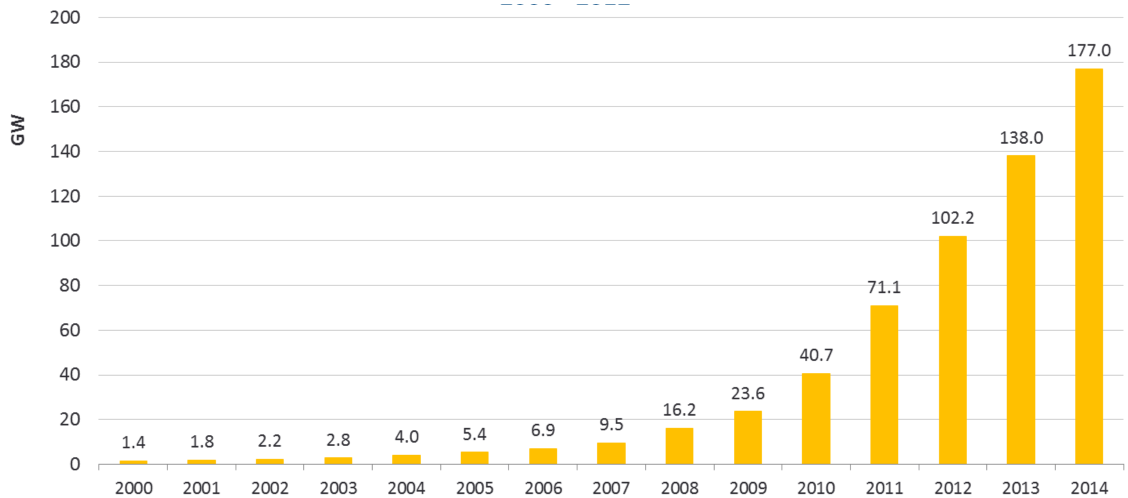
Renewables 2015, Global Status Report, Renewable Energy and Policy Network for the 21st Century, and Global Cumulative Installed Wind Capacity 1996-2012, Global Wind Energy Outlook, 2012.

---

14 Renewables 2015, Global Status Report, Renewable Energy and Policy Network for the 21st Century, Page 71 and Global Wind Energy Outlook (GWEO), 2012, Annual Installed Capacity by Region 2005-2012, Page 13.

15 Renewables 2015, Global Status Report, Renewable Energy and Policy Network for the 21st Century, Page 59.

Figure 10
Global PV Cumulative Installed Capacity
2000 - 2014



Sources/Notes:

Renewables 2015, Global Status Report, Renewable Energy and Policy Network for the 21st Century, and Global Market Outlook for Photovoltaic 2013-2017, EPIA.

The cost of generating electricity from these renewables resources has declined significantly over time, due to technological change and manufacturing advancements, economies of scale, and performance improvements. For example, since 2009 wind turbine prices have fallen by 20% to 40%. This has contributed significantly to U.S. installed costs falling by \$580/kW since 2009 to \$1710/kW in 2014, a reduction 25%.[16] Solar PV system costs have fallen by 75% in less than 10 years.[17]

Despite the small temporary increase in wind generation capital costs between 2005 and 2010 (driven by rising commodity and raw materials prices, increased labor costs, improved manufacturer profitability, and turbine improvements), the cost of wind generation is expected to continue to fall (but at a slower pace) given expectations of continued increases in turbine size, design advancements and possibly lower capital costs. Solar PV costs are expected to continue declining more significantly. As shown in Figure 11, according to the World Energy Outlook 2013 published by the IEA, the capital cost of wind projects in Europe is projected to decrease

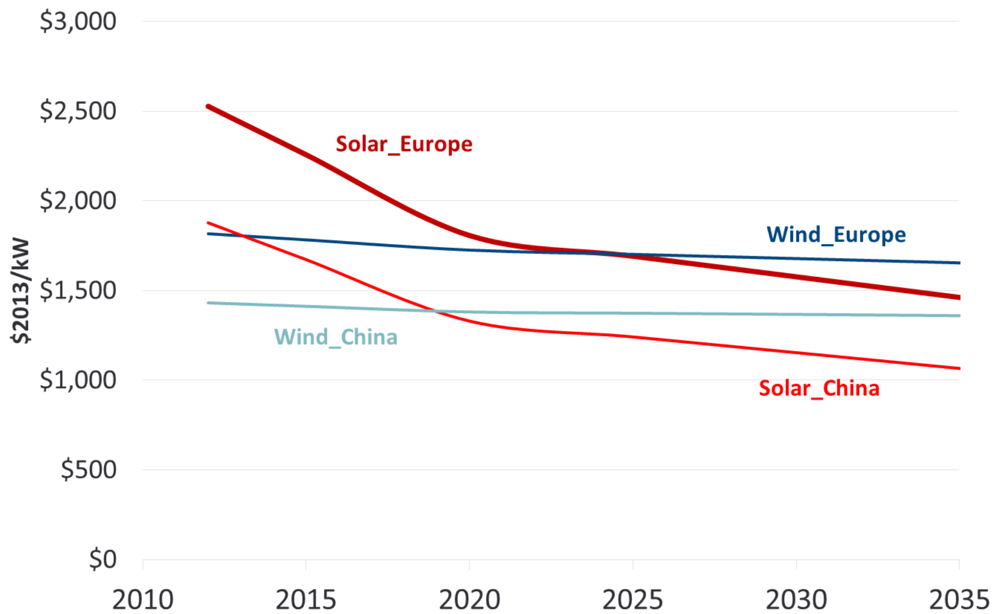
---

[16] 2014 Wind Technologies Market Report, Department of Energy, Aug, 2015.

[17] Source: Global Market Outlook For Solar Power / 2015 – 2019, Solar Power Europe, 2014

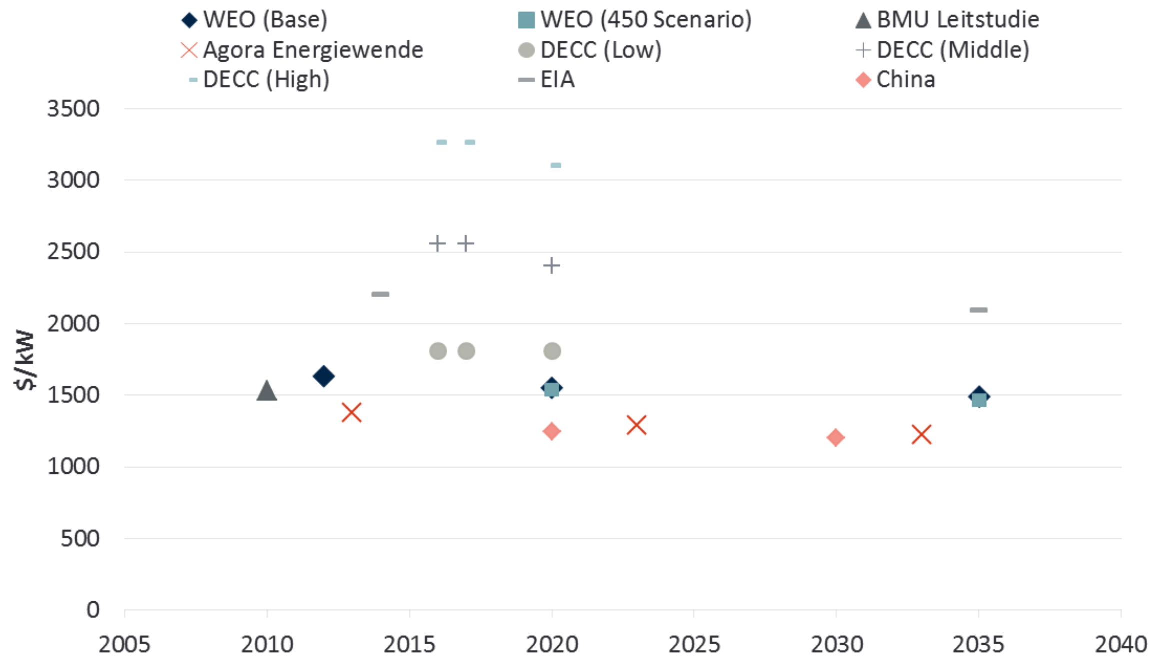
from $1790/kW in 2012 to $1630/kW in 2035, a reduction of about 10%. Capital costs for utility scale solar PV in Europe are expected to decrease from $2500/kW in 2012 to about $1800/kW in 2020, and further decline to $1440/kW by 2035, a reduction of more than 40%. In other countries, such as China, renewables are expected to experience similarly declining costs. While the cost of renewables differs significantly by location and technology (due to differences in resource quality and the maturity of local markets), the IEA cost projections are broadly in line with projections made by other organizations, as shown below in Figure 12 and Figure 13. As such, we use the IEA figures in our analysis and report the results here.

Figure 11
Projected Capital Cost for Wind and Solar Power Plants by WEO 2013



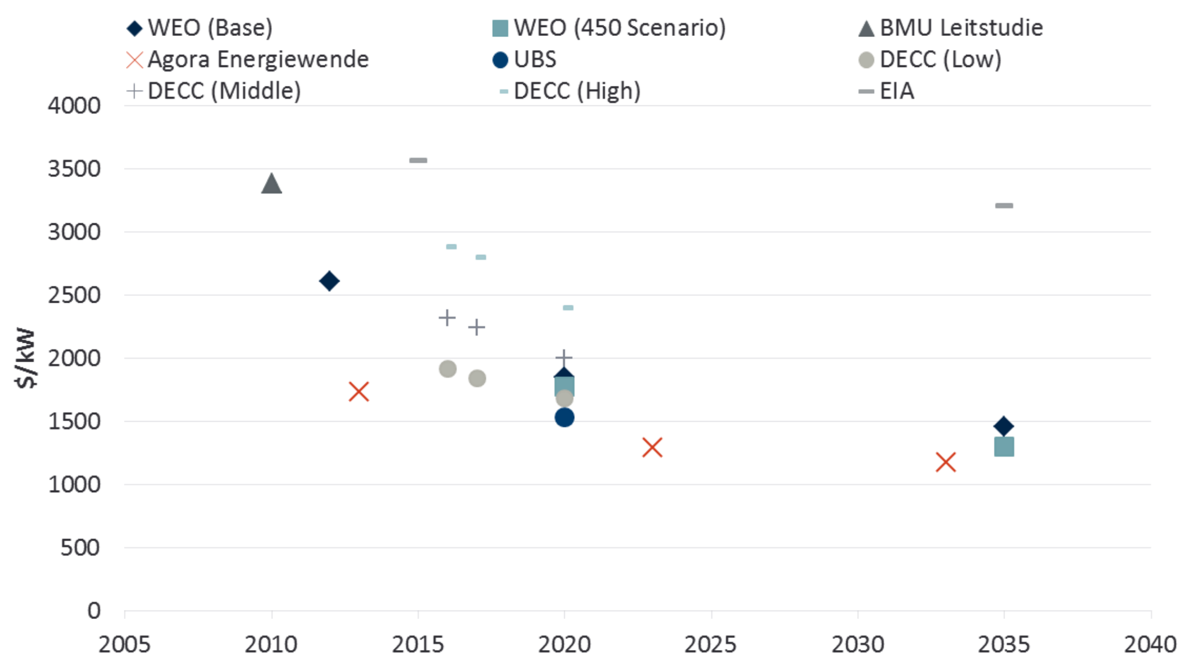
Sources/Notes:
World Energy Outlook 2013, NPS Scenario

Figure 12
Wind Capital Cost Projections by Different Organizations



Notes: when regional figures are reported, average across regions is taken.

Figure 13
Solar PV Capital Cost Projections by Different Organizations



Notes: when regional figures are reported, average across regions is taken.

Although renewables (especially solar) may not have reached grid parity (*i.e.,* a cost that makes them cost-competitive with incumbent fossil-fuel fired generation) in many markets, and may not do so for some time, continued technological improvements will likely allow renewables to increasingly compete with conventional fossil technologies, such as natural gas fired electricity generation, especially in countries where natural gas prices are high or if natural gas prices increase over time.

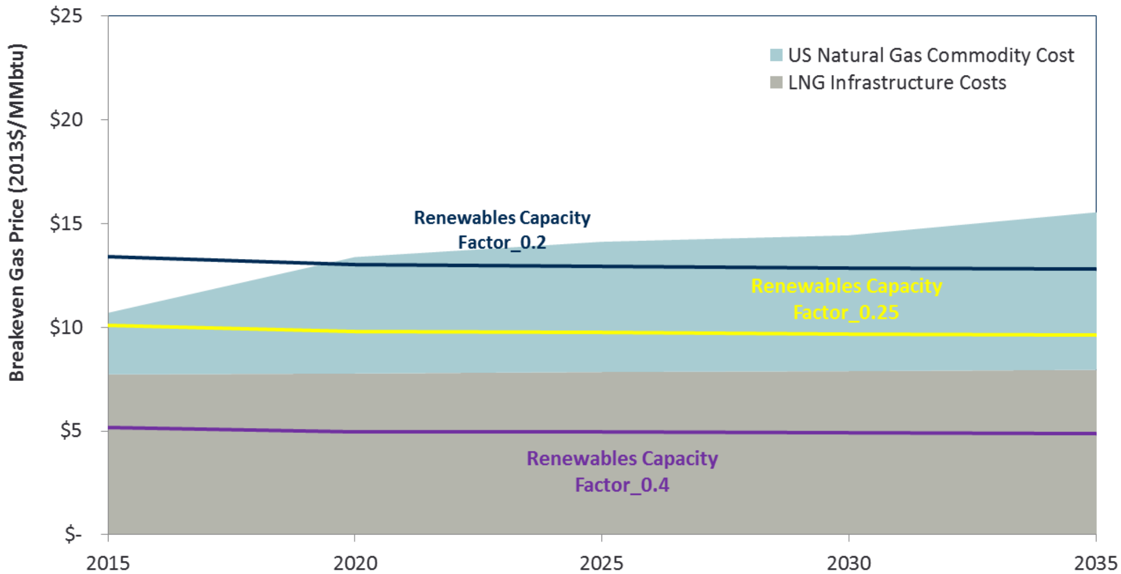
The next section explores the relative economic attractiveness of renewables and natural gas fired power plants fueled with U.S.-sourced LNG by using China and Germany as examples since both countries are experiencing rapid development of renewable technologies and have to rely largely on imported natural gas supplies (including, potentially, imported LNG) for meeting the fuel requirements of their natural gas fired power plants.

IV.Comparing the Cost of LNG and Renewables

Figure 14, Figure 15, and Figure 16 combine the insights from the above two sections by comparing the forecast delivered cost of U.S.-sourced LNG (shaded regions) expressed in $/MMBtu with the equivalent cost of wind, solar and a combination of wind and solar, also expressed in $/MMBtu, (*i.e.,* as the price of natural gas at which the respective technologies break even).[18] As described above, actual landed prices may be quite different from the delivered cost of LNG. In the analysis below, we use the forecasted delivered cost of LNG (including all infrastructure costs) as a proxy for the price of LNG. As long as the delivered cost of LNG is below the break-even prices for renewables (expressed in $/MMBtu), generating electricity using LNG would be less expensive than generating power from renewable sources. Conversely, if the delivered cost of LNG is above the break-even prices for renewables, then generating electricity using renewables would be less expensive than generating power from LNG.

18 First, we calculate the levelized cost of electricity (LCOE) for renewables in $/MWh using assumed capital costs, fixed operations and maintenance (FOM) costs and renewable capacity factors. We then transform this LCOE in $/MWh into an equivalent gas price in $/MMBtu by calculating the natural gas price that makes the LCOE (in $/MWh) of a new combined cycle gas plant equal to the calculated LCOE for renewables in $/MWh (using assumed capital costs, FOM, VOM, and heat rate of a new gas-fired combined cycle power plant).

Figure 14
Breakeven Analysis for Wind Renewables and New Gas-Fired Combined Cycle in China Based on Forecast Delivered Cost of LNG from U.S. to China

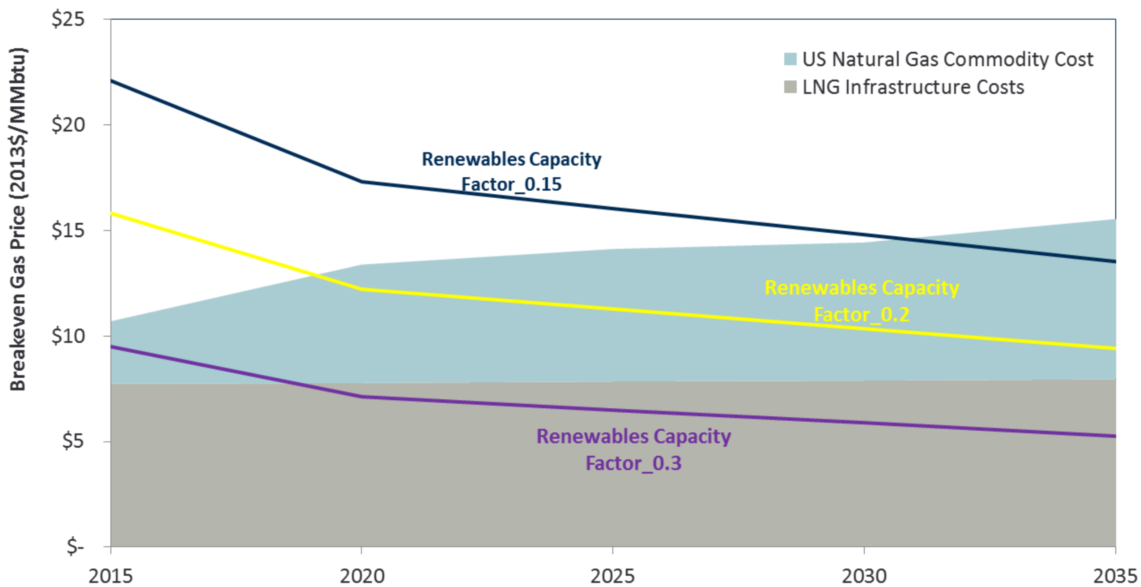


Sources/Notes:
World Energy Outlook 2013 for renewables cost assumptions (NPS Scenario).
Delivered LNG cost breakdown from Figure 7.

As can be seen from Figure 14, it appears that generating power in China using wind with a capacity factor of 25% or greater would already be competitive with generating power with new combined cycle gas turbines using LNG. Such wind capacity factors are not unrealistic for some locations in China.[19] By 2020 or 2025, about the time when many of LNG projects now under consideration (but that have not yet advanced to construction) might be able to deliver LNG, wind with a capacity factor of 20% becomes competitive with generation using LNG. Based on this simplified analysis, capacity factors of between 20% and 25% would suffice for wind to be cheaper than LNG over the typical LNG contract length of 20 years.

[19] McElroy, Michael B., Xi Lu, Chris P. Nielsen, and Yuxuan, Wang. 2009. Potential for wind-generated electricity in China, Science 325(5946): 1378-1380, Figure 1.

Figure 15
Breakeven Analysis for Solar PV and New Gas-Fired Combined Cycle in China Based on Forecast Delivered Cost of LNG from U.S. to China



Sources/Notes:
World Energy Outlook 2013 for renewables cost assumptions (NPS Scenario).
Delivered LNG cost breakdown from Figure 7.

Figure 15 shows that electricity generation from solar PV is more expensive than generation from new gas-fired plants using LNG through approximately 2020 unless the solar capacity factor is 20% or higher. But if technology development reduces the cost for solar and gas prices increase over time, solar with a capacity factor of 15% could become competitive with gas before 2035.

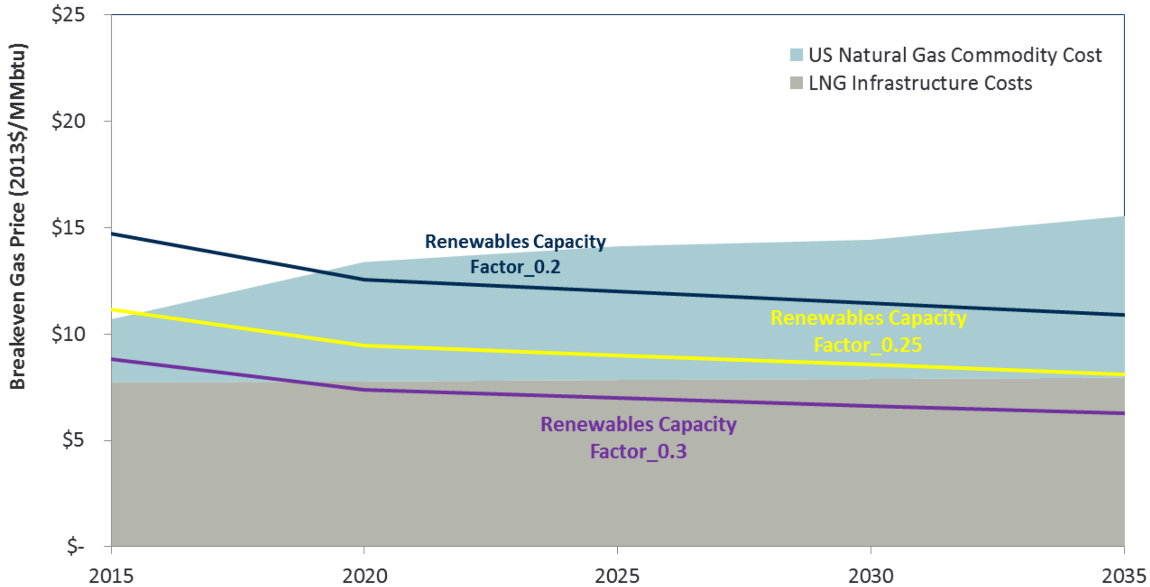
However, this does not mean that solar with a capacity factor of 15% should not be considered competitive relative to a gas-fired plant before 2035. The reason is that solar can complement wind in that wind speeds tend to be lower in the summer (in the northern hemisphere) when the sun shines brightest and longest, and wind tends to be strong in the winter when less sunlight is available. Consequently, since the peak operating times for wind and solar systems occur at different times of the day and year, a hybrid system might better match with demand than wind or solar PV facilities by themselves. To illustrate how this could affect the competitiveness of wind and solar as compared to a natural gas power plant, we constructed a hypothetical hybrid renewable plant composed of both wind and solar PV capacity.[20] The ratio between the two technologies is chosen such that the hourly renewable production profile of the hybrid renewable plant leads to a better match with the hourly load profile than either wind or solar PV alone. The capital cost of the hybrid plant is estimated as the weighted average of the capital costs for the wind and solar plants, and the capacity factor of the hybrid plant is the weighted average of the capacity factors for the wind and solar plants.

Figure 16 shows the breakeven gas price of a hybrid renewable plant in China. The hybrid renewable plant is developed using wind, solar and hourly load profiles in the Midwest region of the U.S. in 2012. Even though it is likely that the actual wind, solar, and hourly load profiles in China are different, the complementarity between wind and solar generation profiles is likely nonetheless applicable, as is the directional impact on the economic attractiveness of a wind and solar hybrid plant. It shows that a mix of wind and solar could well be competitive with LNG around 2020 even if relatively low capacity factor solar (15% capacity factor) is available to complement relatively modest capacity factor wind (25% capacity factor).

---

20 For the hybrid plant, we chose a ratio between wind and solar capacity of 1.25 (for every 1 MW of solar PV there are 1.25 MW of wind generation capacity). Although this may not be a system that can best match load at least cost - determining the optimal mix would require a much more complicated analysis - it represents one possible hybrid system that better matches the load than wind alone. This means that if, for example, the capital cost in China by 2015 is about $1390/kW for a wind plant and $1650/kW for a solar plant, as assumed in WEO 2013, and the capacity factors for wind and solar are 25% and 15% respectively, the hybrid renewable plant in China is assumed to have a capital cost of $1520/kW and a weighted-average capacity factor of 20.6% (close to the 20% line we show in the graphs). Similarly, with this capacity ratio, a wind capacity factor of 30% and a solar capacity factor of 20% results in a capacity factor of 25.6% for the hybrid plant. A wind capacity factor of 40% and a solar capacity factor of 20% results in a capacity factor of 30.6% for the hybrid plant.

Figure 16
Breakeven Analysis for Hybrid Renewables and New Gas-Fired Combined Cycle in China Based on Forecast Delivered Cost of LNG from U.S. to China



Sources/Notes:
World Energy Outlook 2013 for renewables cost assumptions (NPS Scenario),
Delivered LNG cost breakdown from Figure 7.

Figure 17, Figure 18, and Figure 19 below show a similar analysis for the breakeven gas prices for wind, solar PV, and hybrid renewables in Germany.[21] Note that there are no LNG import terminals currently operating in Germany.[22] For illustrative purposes, we use the forecast cost of U.S. LNG delivered to Europe to represent the cost of LNG for Germany. As shown in Figure 17, currently wind with a capacity factor of 30% would already be cheaper than a new gas-fired plant fueled with LNG imported from the U.S. Wind with a capacity factor of around 25% would become competitive before 2020; and wind with a capacity factor of 20% would become competitive by 2035. Typical annual capacity factors for German on-shore wind facilities are

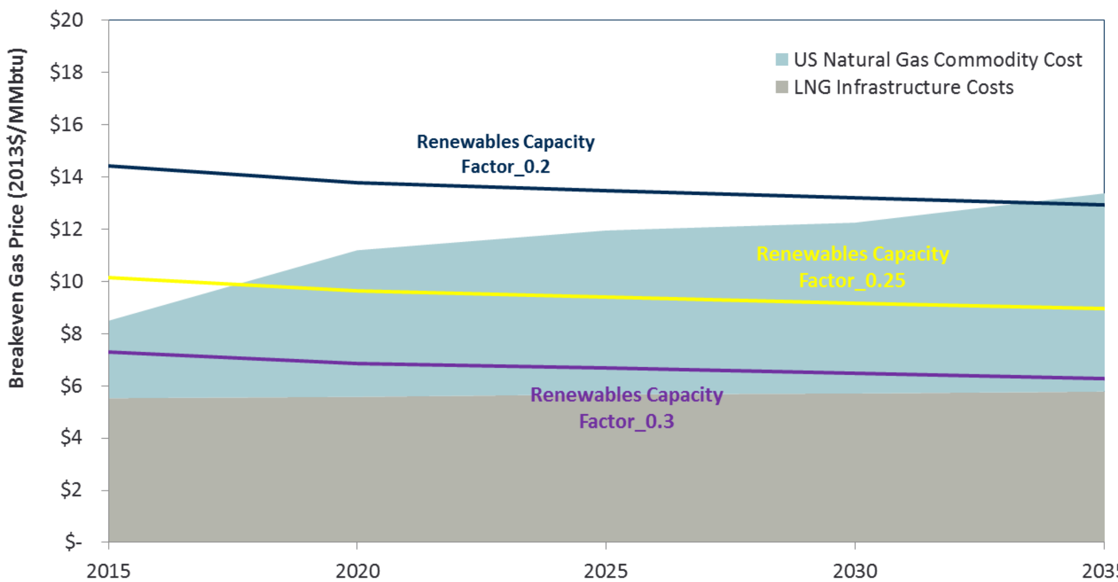
[21] The hybrid renewable plant is constructed using 2012 wind, solar, and hourly load profiles from 50Hertz and Amprion, two of the transmission service operators in Germany, A capacity ratio between wind and solar of 1.25 also leads to a better match with the load profile than wind alone.

[22] EIA Country Profile - Germany, http://www.eia.gov/countries/country-data.cfm?fips=GM&trk=m, accessed on May 6, 2014.

currently between 20-25%,[23] so that at least some wind appears to be competitive with LNG-fueled gas-fired power generation over the time horizon of typical LNG contracts. However, the current forecast cost of delivered LNG of roughly $8-13/MMBtu results in cheaper power production from imported LNG than solar PV at solar capacity factors below 20% (see Figure 18). Typical solar PV capacity factors in Germany are 15% at best, suggesting that gas-fired power generation should be less expensive than PV power, even if such generation were fueled by imported LNG. However, solar as a part of a hybrid renewable plant with a capacity factor of 20% would be cost-competitive with LNG-fueled gas-fired power generation around 2030 and before 2020 if the capacity factor is 25% (see Figure 19). Given typical capacity factors, in particular for onshore wind in Germany, it seems unlikely that a hybrid wind-solar plant would be able to reach such a capacity factor in the foreseeable future, at least absent explicit pricing of avoided CO_2 emissions, an issue we discuss next.

Figure 17

Breakeven Analysis for Wind Renewables and New Gas-Fired Combined Cycle in Germany Based on Forecast Delivered Cost of LNG from U.S. to Europe



Sources/Notes:

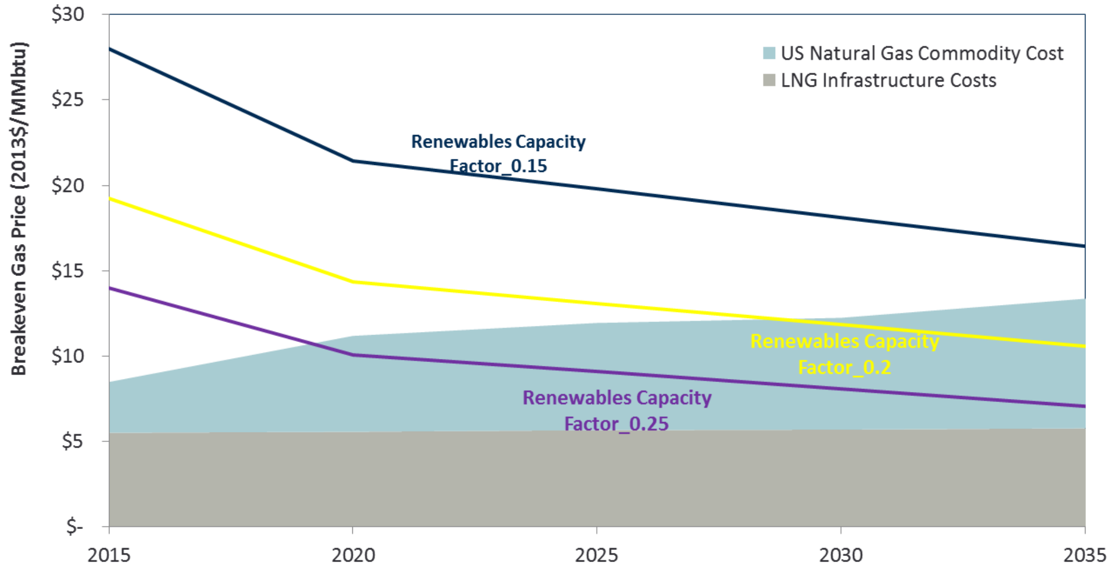
World Energy Outlook 2013 for renewables cost assumptions (NPS Scenario)

Using forecast of delivered cost of U.S. LNG to Europe from Figure 8.

---

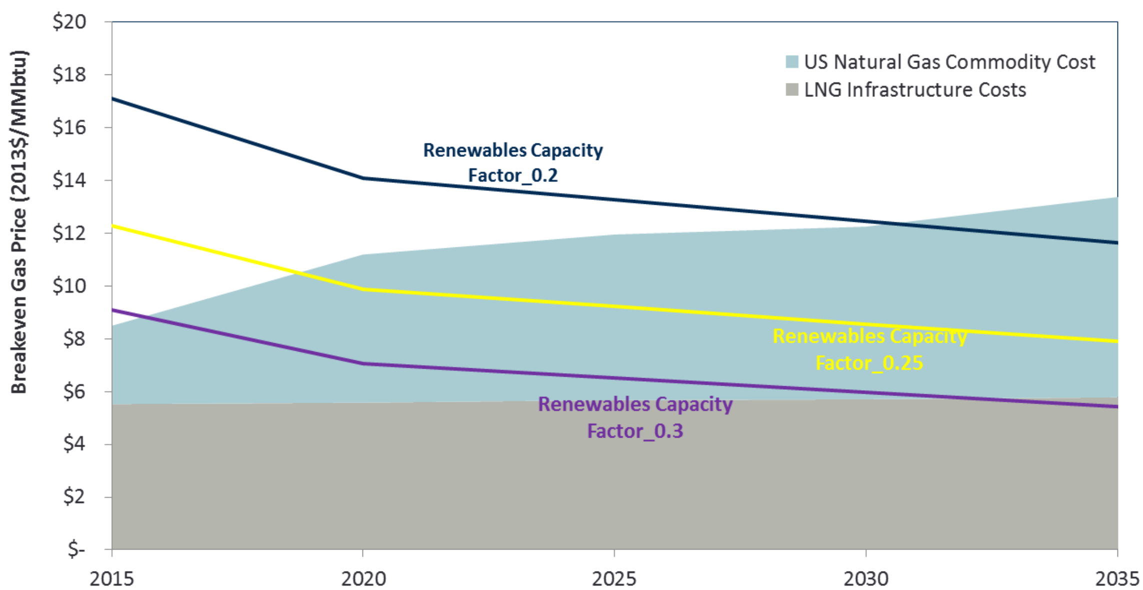
[23] See, for example, Fraunhofer ISE, Stromgestehungskosten Erneuerbare Energien, November 2013, page 13, which assumes the equivalent of 2000 hours of power generation at full capacity for better on-shore wind sites in Germany, the equivalent of a 23% annual capacity factor.

Figure 18
Breakeven Analysis for Solar Renewables and New Gas-Fired Combined Cycle in Germany Based on Forecast Delivered Cost of LNG from U.S. to Europe



Sources/Notes:
World Energy Outlook 2013 for renewables cost assumptions (NPS Scenario)
Using forecast of delivered cost of U.S. LNG to Europe from Figure 8.

Figure 19
Breakeven Analysis for Hybrid Renewables and New Gas-Fired Combined Cycle in Germany LNG Delivered Cost Breakdown from U.S. to Germany



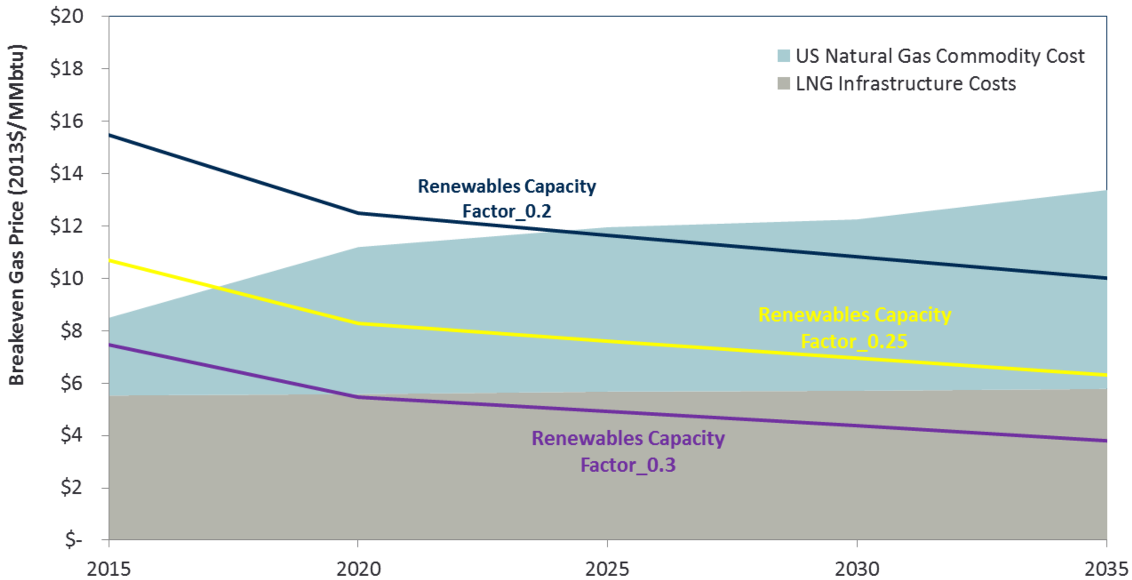
Sources/Notes:
World Energy Outlook 2013 for renewables cost assumptions (NPS Scenario)
Using forecast of delivered cost of U.S. LNG to Europe from Figure 8.

Including the cost of carbon emissions associated with gas-fired power generation would make gas-fired power generation more expensive relative to renewables. While there is a lot of uncertainty about the price of carbon in Europe going forward, the European Union's (EU) ambitious long-term GHG reduction goals and past EU Emission Trading Scheme (ETS) prices suggest that a price of $30/ton of CO_2 to illustrate the impacts of carbon prices on the competitiveness between renewables and LNG in Germany is reasonable.[24] An allowance price of $30/ton of CO_2 would add about $1.60/MMBtu to the cost of LNG, or about $10/MWh for the electricity generated from a new gas-fired combined cycle plant with a heat rate of about 6,200 Btu/kWh (as assumed by WEO 2013). This results in the breakeven prices shown in Figure 20. As shown, at a $30/ton carbon price, a hybrid renewable plant with a capacity factor of 20% (achievable for example with a combination of wind at a capacity factor of 25% and solar at a capacity factor of 15%) would be competitive with an LNG-fueled gas-fired plant before 2025, about 5 years earlier than without the inclusion of the value of avoided greenhouse gas emissions.

---

[24] Allowance prices under the European Union Emissions Trading Scheme ("EU ETS") ranged between €20 and €30/ton of CO_2 prior to the financial crisis of 2008. $30/ton corresponds to approximately €22/ton at current exchange rates. While current prices under the EU ETS are far below this historic level, there is widespread agreement that low current allowance prices are not reflective of the levels needed to achieve the EU's longer term carbon reduction goals.

Figure 20
Breakeven Analysis for Hybrid and New Gas-Fired Combined Cycle in Germany with Carbon Emissions' Cost of $30/ton
Based on Forecast Delivered Cost of LNG from U.S. to Europe



Sources/Notes:
World Energy Outlook 2013 for renewables cost assumptions (NPS Scenario)
Using forecast of delivered cost of U.S. LNG to Europe from Figure 8.

Figure 20 shows that pricing GHG emissions could further tip the scale in favor of renewable energy sources even in places such as Germany, where neither wind nor solar PV resource quality is very high.[25] When and how highly GHG emissions will be valued (either explicitly through the creation of carbon markets or carbon taxes or indirectly through policy making that impacts of the choice of generation mix) therefore has a significant impact on how quickly renewable energy sources might gain a cost advantage over LNG-based power generation. Very recent developments in China[26] leading up to the Conference of Parties (COP) in Paris in December 2015 suggest that pricing GHG emissions may happen sooner rather than later.

---

25 Recent U.S. onshore wind projects in the Midwest are achieving capacity factors in excess of 50%. Solar PV plants in the Southwestern United States can achieve capacity factors between 20% and 25%. Some of the difference is due to different resource quality (more wind, more sun), but some is also a reflection of ongoing technological advances, which will likely lead to increased capacity factors of new wind and solar PV resources in Germany as well.

26 China to Announce Cap-and-Trade Program to Limit Emissions,

Continued on next page

V. Discussion

The above analysis shows that renewable energy may be able to compete with imported LNG under a number of conditions in the near future and most likely during the lifetime of the long-term LNG contracts supporting new LNG export infrastructure (*i.e.,* contracts that have already been negotiated for new export terminals now under construction as well as contracts being pursued by export terminals currently in the development phase). Advances in renewable energy technology and related cost improvements, which are further helped by an increasingly mature supply chain, economies of scale and increased competition, could result in renewables putting competitive pressure on LNG as a source of fuel in the electric generation sector in many target markets for North American LNG. Such competitive pressure could lead to lower demand for LNG relative to current forecasts, and lower prices for LNG in world markets, all else equal.

In areas with good conditions for renewable energy production (high average wind speeds and/or high solar irradiation) renewable energy is already beginning to compete with fossil generation, even at relatively low natural gas prices and generally with low or no price on carbon. Evidence of this competition can be seen in some of the recently signed long-term renewable contracts in the United States – where gas prices are amongst the lowest in the world – at prices that are deemed to be lower than those from competing fossil fuels, and in particular gas-fired generation projects. For example, in 2014 the national average levelized price of wind PPAs that were signed fell to around $23.5/KWh in the U.S.[27] PPAs for solar PV projects have also decreased significantly, with some evidence that in good locations long-term contracts can be obtained at prices below $40/MWh.[28] Even if existing subsidies for renewable energy sources are netted out of these prices,[29] renewable energy sources in these examples would in the worst case not be

---

Continued from previous page

http://www.nytimes.com/2015/09/25/world/asia/xi-jinping-china-president-obama-summit.html?_r=0.

27 See, for example, U.S. Department of Energy, 2014 Wind Technologies Market Report, August 2015, page 56.

28 http://www.utilitydive.com/news/nv-energy-buys-utility-scale-solar-at-record-low-price-under-4-centskwh/401989/, accessed on October 7, 2015.

29 Solar PV projects benefit from an investment tax credit covering 30% of the investment costs. Until year-end 2013, wind projects benefitted from a production tax credit of 23 cents/kWh, and all renewable projects benefit from accelerated depreciation allowances.

significantly more expensive than power from new gas-fired generation, and in many cases cheaper. In this sense, the recent experience in the United States is an illustration of the declining break-even cost of renewable alternatives to natural gas fired power generation.

These trends in the costs of renewables suggest some risks associated with the use of LNG for gas-fired power generation in overseas markets, and for purchasers of LNG under long-term contracts who may be counting on strong world LNG demand for power generation based on the presumption that power generation using LNG will be cheaper than non-gas generation alternatives such as renewables. We discuss these risks and uncertainties in the next section.

It is, however, important to recognize that our analysis is deliberately simple and thus omits factors that would likely move the relative cost of imported LNG versus renewables one way or the other. Several factors would have the tendency to improve the value of imported LNG when compared to renewables relative to our simple analysis above.

First and foremost, the results presented above illustrate that the ability of renewable energy to outcompete imported LNG depends critically on the quality of the available renewable resource. In many cases, the ideal locations for renewable energy sources will not be close to load centers, so that potentially significant additional costs will be incurred to bring such resources to market, even if sufficient locations with good resource quality are available. As a case in point, bringing large amounts of high-quality wind power in China to market will likely require very significant investments in additional transmission infrastructure, as the best wind resources are located in the very Western and Northern parts of China, whereas the demand centers are located in the East and South. Corresponding incremental infrastructure costs are likely less important for LNG imports, since large demand centers are often located near the coast and hence LNG infrastructure can be located in relative proximity. Gas-fired power generation can also be located near the coast and the resulting electric transmission to bring power from such plants to load centers will often be less expensive than building transmission infrastructure from Western China to the coast. Hence, if the costs of connecting high quality renewables to demand centers are high, the actual cost of renewables will likely be higher than our estimates.

A second often discussed issue relates to the intermittency of renewable generation and the "integration" costs required to manage the disconnect between renewable generation and demand in contrast with gas-fired generation, which can serve demand reliably and be controlled to reflect fluctuating demand. The level of renewable integration costs depends on the mix of renewable resources used, the amount of renewable energy generation and the shape of the demand. Also, market structures and the available technology to integrate renewables matter. For example, advances in battery technology and associated costs may well lead to lower integration costs in the future. A number of studies have attempted to estimate integration costs as a function of the various factors cited above. In general, cost estimates have shown a range of approximately $2-5 per MWh of renewable generation.[30] This translates to a range of $0.3-0.8/MMBtu, which suggests that, at least at moderate penetration levels, including renewable integration costs would likely not fundamentally alter the results of our analysis. At high levels of renewable generation, integration costs could become much more significant, and consequently the economics of renewables relative to LNG could deteriorate significantly absent cost reductions for enabling technology corresponding to cost reductions for renewable energy itself.[31]

Third, while our comparison of LNG and renewables accounted for expected declines in the cost of renewables, it did not assume reductions in the cost of gas-fired generation or LNG supply chain costs. For example, some project developers in Australia are now considering floating liquefaction projects as a potentially less expensive alternative to onshore LNG projects (with potential savings on the order of 20-30%).[32] Such savings in the cost of LNG export projects or in other parts of the LNG supply chain could improve the economics of LNG relative to renewables.

Fourth, the cost of feed gas for LNG (*i.e.,* the commodity cost of gas) is itself uncertain and will depend upon various factors including the potential for additional technological improvements in the production of natural gas. The uncertainty in the commodity cost of gas directly affects the relative attractiveness of renewables and LNG. If, for example, the commodity cost of gas in the U.S. is lower than the projections we have assumed (resulting in a lower delivered cost of LNG), LNG can become more competitive with renewables in LNG destination markets such as China.

---

30 See, for example, Michael Milligan, Wind Integration Cost and Ancillary Service Impacts, presentation, August 10, 2006, which cites many previous studies. Since then, many additional studies have been conducted. One main conclusion is that renewable integration costs increase potentially sharply above some minimum threshold of overall renewable energy penetration.

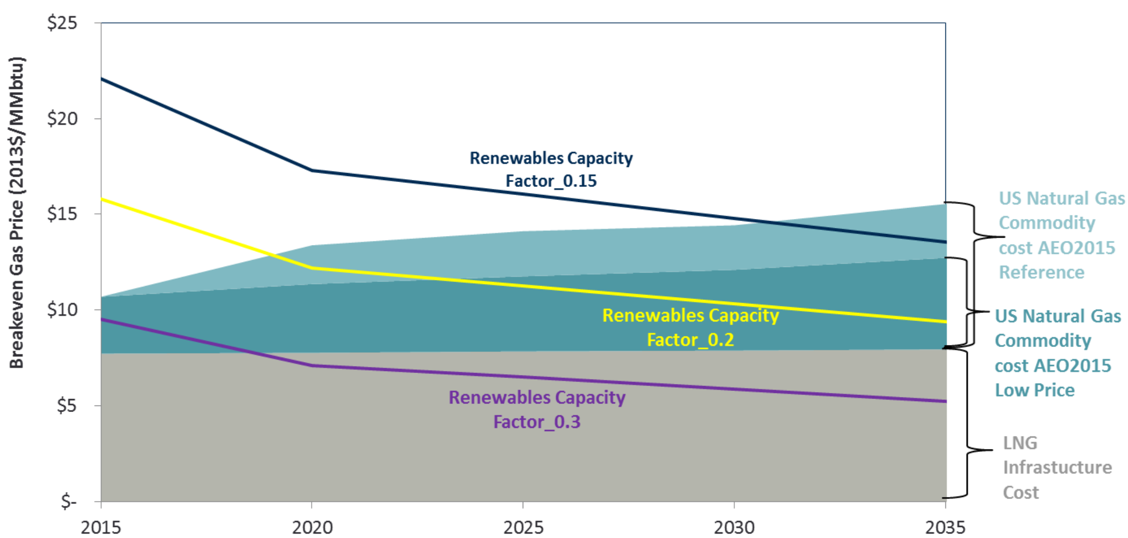
31 It should however be noted that as the deployment of variable renewable generation has increased, so has the ability to integrate these resources through a mix of operational changes, market rule changes, and technology. As a consequence, the penetration threshold of renewable resources that would result in significantly higher integration costs will likely continue to increase.

32 See "High-Cost Australia May Miss $180 bln LNG Expansion Wave," Reuters, April 11, 2014.

As an example, Figure 21 recreates the comparison between the cost of solar PV and the cost of gas-fired generation using LNG in China under two gas commodity cost scenarios-the "Reference Case" (which is the same as in Figure 15 above) and the "Low Price Case". As shown in Figure 21, generating electricity from solar PV with a capacity factor of 20% becomes less expensive than generation using LNG in around 2020 under the "Reference Case" commodity cost projection. However, the same cross-over point occurs roughly five years later in around 2025 under the "Low Price Case".

Finally, renewable energy is subject to important performance uncertainties whereas natural gas combined cycle generation has a longer history of reliable performance. Even though windmills have been around for centuries, current wind technology represents recent advances in engineering. Similarly, PV technology is advancing at a significant pace. As a result, there is likely non-trivial uncertainty regarding the longevity, maintenance costs, and long-term performance of renewable energy facilities being installed today. If the performance of renewable energy projects is less than expected, or if future cost declines for renewables are lower than currently anticipated, the economics of LNG versus renewables would also shift in favor of LNG.

Figure 21
Breakeven Analysis for Solar PV and New Gas-Fired Combined Cycle in China
Based on Forecast Delivered Cost of LNG from U.S. to China



Sources/Notes:
World Energy Outlook 2013 for renewables cost assumptions (NPS Scenario)
Delivered LNG cost breakdown for the Reference Case from Figure 7. The 2020-2035 Low Price commodity cost is based on 115% of Henry Hub prices from EIA AEO 2015 High Oil and Gas Resource case. 2015 commodity cost (for both Reference Case and Low Price Case) is based on 115% of 2015 Henry Hub price reported in EIA's Dec 8, 2015 STEO.

However, there are also factors that could shift the balance further in favor of renewables. First, unlike renewable energy sources, which can be scaled from just a few kW for single rooftop solar PV systems or a few MWs for small wind projects to 100s of MWs for large wind or solar farms, traditional onshore LNG infrastructure projects represent huge one-time commitments of capital and result in hyper-complex building projects such as those in Australia, where the most expensive projects have capital costs ranging from $30-$60 billion. There is significant evidence that with large single infrastructure projects the risks of cost-overruns and completion delays are substantial. In fact, several of the Australian LNG projects have experienced significant cost-overruns. Both cost-overruns and construction delays can have substantial, negative effects on the economics of such projects, although some contracting practices (such as cost-sharing provisions) can help mitigate these impacts. These types of cost-overrun risks are not accounted for in our analysis.

Second, as discussed above, the environmental advantages of renewables and the potential inclusion of carbon costs in the future would further improve the economics of renewables relative to LNG, as shown in our analysis of Germany. However, it is important to mention that climate change considerations work against imported LNG if imported LNG is assumed to displace renewable energy production. If, on the other hand, LNG imports were to displace new or existing coal-fired generation, LNG imports could provide a significant and positive contribution towards reducing greenhouse gas emissions. Of course for LNG to displace coal but not renewable energy (even in cases where our charts show renewable energy may be cheaper) would require that LNG would be cheaper than coal, but that somehow even cheaper renewable energy does not displace coal. While this would seem unlikely in theory, it may well be the case in practice, due to any number of factors, many of which are likely very location/country and context specific, such as the fact that the time required to get new transmission infrastructure for renewable energy planned, approved, financed and built may be significantly longer than the time required to build new coal-fired generation or the fear that renewable energy may not be "reliable" enough to displace traditional fossil power generation sources.

To summarize, while the relatively simple analysis presented in this paper leaves out important factors affecting the relative attractiveness of LNG-fueled and renewable power generation, it does not appear that the omission of these factors clearly bias our results one way or another.

VI. Electric Market Uncertainties and Gas Market Competition: Implications for LNG Markets

The electric power sector is a critical sector impacting worldwide natural gas and LNG markets. Uncertainty regarding the future mix of electric generation capacity creates uncertainty in demand for natural gas and LNG. Thus, developments in the electric sector have important ramifications for natural gas markets. The competition between gas-fired generation capacity and other types of power plants (renewables as discussed in this paper, but also potentially nuclear) creates risks for participants in natural gas and LNG markets.

Forecasts of LNG demand (as distinct from natural gas demand) made prior to the recent oil price collapse projected LNG demand growth from current levels of about 32 Bcf/d to levels of 65-85 Bcf/d by 2030 (*i.e.,* growth of 33 to 53 Bcf/d).[33] More recent forecasts of LNG trade (following the collapse in oil prices) have varied widely. For example, BP's Energy Outlook 2035 (released in February 2015) projected LNG demand to grow from 32 Bcf/d to roughly 70 Bcf/d by 2030 and to approximately 80 Bcf/d in 2035.[34] IEA's World Energy Outlook 2015 (released in November 2015) projects significantly lower growth in LNG trade, to approximately 40 Bcf/d by 2025 and to roughly 50 Bcf/d by 2040 (*i.e.,* growth on the order of roughly 18 Bcf/d between now and 2040).[35] The uncertainty in LNG demand, as shown by this range of forecasts, is substantial. Reduced gas demand in the power sector, as a consequence of the factors described in this paper (which could also include more nuclear generation in addition to a shift towards more renewables, as a result of cost and/or climate change issues), could have a significant impact on overall LNG demand and thus the need for LNG liquefaction terminals. For example, a 6 Bcf/d reduction in LNG demand would be the equivalent of three to six fewer LNG liquefaction terminals (assuming an average LNG terminal size of 1.0-2.0 Bcf/d).

In general, the uncertainties in the electric power sector, especially in Asian markets, combined with other uncertainties are creating significant risks in global LNG markets. In the near-term, global LNG markets can be characterized as a buyer's market due to the oversupply conditions

---

33 See, for example, "US Manufacturing and LNG Exports, Economic Contributions to the US Economy and Impacts on US Natural Gas Prices," Charles River Associates, February 25, 2013, page 31.

34 See BP Energy Outlook 2035, slide 56.

35 IEA World Energy Outlook 2015, Reference Case (New Policies Scenario), page 220.

that have developed recently. Spot LNG prices in the aftermath of the oil price collapse have converged globally to the $7/MMBtu range. Gas demand growth has slowed in key Asian and European markets for a variety of reasons, including mild winters, the availability of cheap coal, the development of renewable resources, and slower economic growth. In addition, new LNG supplies have started to come online, such as the Queensland Curtis Island LNG project in eastern Australia. These conditions may persist or worsen over the next several years as a substantial amount of additional new LNG liquefaction capacity is set to enter service both in Australia (8 Bcf/d of new liquefaction capacity) and the U.S. (9 Bcf/d) between 2015 and 2020. A restart of some of Japan's nuclear fleet may also result in lower LNG demand for power generation by Japan, further contributing to the oversupply situation in the next few years.

Thus, the questions facing global LNG markets today are how quickly the new LNG supplies coming on line over the next few years will be absorbed, and at what point in the future there might be a rebound in global LNG prices such that new LNG export terminals (beyond the terminals now under construction) are needed. Many market observers believe the answers to these questions will hinge on how gas demand growth (including electric sector demand) develops in Pacific Asian markets, especially markets in China and India. In addition to the dynamic of renewables versus gas competition discussed in detail in this paper, other important factors include overall economic growth in these markets and competition to serve growing gas demand in Asian markets from pipeline imports and indigenous supply sources. A recent example of this competition can be seen in China's decision in May 2014 to enter into a long-term contract for pipeline gas from Russia. The deal is reported to be a 30-year contract under which Russia will supply China with approximately 3.7 Bcf/d of natural gas (roughly the size of 1-2 LNG export terminals), at a price in the range of $9-$11/MMBtu.[36] A second (non-binding) deal between China and Russia was signed in November 2014, also reported to be a 30-year contract under which Russia will supply China with an additional 2.9 Bcf/d of natural gas.[37] China is also understood to have substantial indigenous shale gas resources, but is only in the early stages of developing those resources.

---

36 "Sino-Russian Gas and Oil Cooperation: Entering into a New Era of Strategic Partnership?" Oxford Energy Institute, April 2015, pp. 7-8.

37 Id., pp. 8-10.

From the North American perspective, the current market conditions and future uncertainties create various risks. The five LNG liquefaction terminals now under construction in the US have largely shielded themselves from these risks by signing long-term offtake contracts with LNG buyers. The US LNG offtake agreements are typically structured such that the purchaser agrees to take LNG at the tailgate of an LNG export plant, at a price linked to Henry Hub (usually multiplied by a scalar, e.g. 115% of Henry Hub), plus a fixed infrastructure charge to cover liquefaction in the range of $3/MMBtu. Thus, the energy companies signing contracts for U.S.-based LNG are assuming the risk that Henry Hub prices may become uneconomic in world markets, in which case they can forgo exporting LNG from the US, but still have to pay the infrastructure charge to the LNG developers (which must be paid even if the buyer does not take LNG from the facility). Thus, it is the LNG buyers in these long-term agreements that are exposed to global LNG conditions. The LNG developers are shielded from these conditions, at least during the term of their initial contracts with buyers, unless the buyers go bankrupt or otherwise default on their obligations. The risk facing the LNG buyers that purchase under these long-term agreements with LNG exporters is likely significant, especially if the buyers are signing up for U.S. LNG export capacity in advance of signing LNG sales contracts with ultimate customers. The buyers of U.S.-sourced LNG are hoping strong gas demand growth is forthcoming in global gas markets so as to make their long-term contractual commitments for U.S. LNG profitable.

More generally, the current market conditions and longer-term uncertainties create the risk that market participants may not be willing to enter into additional long-term commitments for LNG export capacity in North America until some of the uncertainties (with respect to overseas gas demand, including electric sector gas demand, in turn partially determined by the dynamics described in this paper, and need for North American LNG) are resolved or become clearer. With the decline in oil and LNG prices, North American LNG (with Henry Hub linked pricing) may not be as attractive an option as it was prior to the price collapse, and oil-linked LNG might be seen as a more competitive alternative. Some observers have forecast that of the dozens of proposed U.S. export projects, only the five export terminals now under construction will be operational before 2020.[38] Moreover, some proposed LNG terminals have been delayed, most

38 See, for example, "LNG Projects Not Viable at $65/b Crude: Report," Gas Daily, June 2, 2015 (referencing Bentek Energy's expectation that only Cove Point, Sabine Pass, Freeport, Cameron, and Corpus Christi will be operational before 2020).

notably BG postponing an expected final decision regarding the Lake Charles LNG facility from 2015 to 2016.[39] BG's postponement in deciding to move forward is particularly significant and is indicative of the uncertainties now facing the LNG markets following the collapse of oil and LNG prices.

The current market also creates uncertainties for the more than twenty LNG projects proposed in Canada. Unlike the U.S., none of the LNG export projects proposed in Canada has advanced to the construction phase, which provides further evidence of the uncertain need for North American LNG. These Canadian green field projects likely have some disadvantages relative to some of the US-based projects that already have infrastructure and certain permits in place as they were initially developed as LNG import terminals. Also, the Canadian projects require significant investment in upstream pipeline infrastructure that is not as easily sited and approved as is the case in the U.S. Gulf Coast.

Nonetheless, some of the Canadian LNG projects have attracted equity investments from Chinese energy companies, such as Sinopec's investment in the Pacific Northwest LNG project, PetroChina's investment in LNG Canada, and China National Offshore Oil Corporation's (CNOOC's) investment in Aurora LNG. The Pacific Northwest LNG project is reported to have made a final investment decision that is conditional on various approvals by Canadian governmental authorities. The participation of Chinese energy companies in these Canadian projects—as equity investors and as potential or likely buyers of the LNG from these projects—indicates that these companies may themselves be keeping their LNG procurement options open while they wait to see how LNG demand in China unfolds. The relative cost of renewables versus power generation fueled by LNG, discussed at length above, will be one of the potential factors to monitor as they consider whether to move forward with purchase agreements for Canadian-sourced LNG.

Another factor is that Chinese energy companies have alternatives to North American LNG, including LNG sourced from Australia and Russia. In Australia, Sinopec has an equity stake in the Australia Pacific LNG project and in Russia the China National Petroleum Corporation (CNPC) has an equity stake in the Yamal LNG project being developed in the Russian Arctic.

---

39 See "US LNG Projects Hit by Energy Price Slide," Reuters, March 13, 2015.

In sum, the need for LNG from North American sources in the medium term (2020 and beyond) is subject to many uncertainties. Among these, as discussed in this paper, will be the extent to which natural gas is consumed for power generation in Asian market versus alternatives such as renewables, but potentially also nuclear, as well as the competition to serve evolving natural gas needs from competing sources (pipeline gas, indigenous supply, and other sources of LNG).

VII. Conclusions

Our analysis suggests that even though the availability of substantial supplies of low-cost unconventional gas resources in North America would point to significantly increased market potential for LNG exported to Asia and perhaps Europe, the traditional comparison of delivered LNG prices to prevailing oil prices may miss an important dynamic, namely the fast progress of renewable energy technologies capable of providing an alternative to one or more of the major sources of demand for LNG, electricity production and in the future perhaps heating.

With all the caveats discussed above, it appears that in many potential markets for LNG exports, the relative economics of LNG and renewables may in the coming years be less favorable to LNG imports than casual enthusiasm about the potential for vastly increased LNG exports suggests. While our analysis by no means implies that there is no need or no sound economic rationale for some—and potentially significant—increases in LNG exports, our analysis does suggest that a more precise estimation of how much incremental demand for LNG imports can be justified based on economics alone requires a more detailed analysis of country-level circumstances.

It seems relatively certain that the progress of renewable energy technologies will continue for some time. It also seems at least conceivable that significant technological progress along the LNG supply chain is at least possible. These dynamics raise important questions and answers to these questions will likely be helpful in assessing the risks of investing in, building, or buying from future LNG infrastructure.

Perhaps the single most distinguishing feature of LNG infrastructure with respect to the risks we discuss is the fact that LNG supplies require massive, sunk and largely irreversible investments in infrastructure. Such investments tend to require certain revenue streams for decades or, alternatively, very large balance sheets with an appropriate appetite for the risks involved. More generally, some of the important risks facing LNG markets include:

- Risk to project developers, owners of LNG projects, and LNG export capacity holders due to uncertainties related to gas and ultimately LNG demand (and LNG prices);
- Stranded asset/contract risk;
- Price risks for counterparties related to price review clauses in LNG contracts;
- Competition from pipeline imports or LNG imports from other regions, or from the development of indigenous gas supplies;
- Risk for potential buyers that commit to a long-term LNG contract (and associated infrastructure) in light of the potential for locally sourced renewable energy to be cheaper; and
- Risk for third party financers to tie up large amount of investment dollars for potentially marginal infrastructure investments.

The purpose of this paper is to raise what we believe to be a relevant set of considerations at a high level. Perhaps the key insight, not limited to this topic but particularly relevant in our context, is that option value is of particular importance when making large irreversible investment decisions in a quickly changing world. This lesson applies both to potential buyers and sellers of LNG. For buyers, signing long-term contracts represents such a long-term commitment. Signing such contracts exposes LNG buyers to the risk that their contracts may end up out-of-market, meaning that the prices they pay for LNG and associated infrastructure may be greater than the value LNG has in world markets, or that the their gas-fired generation assets are not competitive in a scenario where the penetration of renewables in the generation mix is particularly strong. For LNG sellers attempting to pass risk on to their customers through long-term contracts, those contracts may ultimately not completely shield the sellers completely from risks of recovering their investment in the LNG export terminals. For example, LNG sellers may face cost over-runs, have customers who default on their obligations (possibly due to market conditions), have price exposure due to contractual price review provisions, or face exposure to re-marketing risks (especially if they need additional time to recover their investments beyond the initial contract period). Hence, our analysis provides high-level support for an argument that both potential buyers and sellers of LNG should carefully analyze the relevant economics of LNG and renewables (along with other factors) as they make investment decisions based on the assumption that LNG will be a natural source of supply to meet increasing electricity demand over the coming decades.

Even though our analysis is primarily motivated by a discussion of the potential use of imported LNG to meet increasing electricity demand, we do not mean to imply that there are not risks associated with LNG demand in the residential, commercial, and industrial sectors (which represent 57% of the total forecasted growth in global gas demand between 2011 and 2035). It is worth pointing out that the traditional separation of gas demand for heating and electricity production is beginning to show at least some signs of weakening. While electric heating has traditionally been primarily confined to areas of minimal heating demand (such as Florida in the United States) or areas with abundant very cheap sources of electricity (Quebec in Canada, for example), technologies such as ground and air-source heat pumps have recently been tilting the economics of heating in favor of electric solutions in more locations. In addition, excess supply of renewable electricity during certain time periods is beginning to incentivize the production of synthetic renewable hydrogen and methane, both of which can be used as perfect substitutes for natural gas in heating (and perhaps even industrial) applications. For the moment, these developments seem largely confined to a few countries such as Germany. The technological progress achieved there however does imply that LNG might face competition from renewable energy sources not just to meet electricity demand, but also in other sectors such as heating and industrial gases, for which there has so far been no alternative to the use of natural gas. Given the longevity of the infrastructure needed to justify LNG in the first place, such developments, even if only in their infancy at present, should be carefully considered when deciding on how to provide energy in various parts of the world over the next 20-30 years.

Finally, since the timeframes for LNG infrastructure development and subsequent contracting of LNG capacity are typically 20 years or longer, the possibility that climate change concerns will become increasingly important going forward can and should not be discounted. As our analysis has shown, even with relatively moderate carbon prices, the economics shift significantly in favor of renewable energy, creating an additional and likely substantial risk for LNG as a fuel in a likely increasingly carbon-constrained future.

CAMBRIDGE
NEW YORK
SAN FRANCISCO
WASHINGTON
TORONTO
LONDON
MADRID
ROME

THE Brattle GROUP

Exhibit 29

100% Clean and Renewable Wind, Water, and Sunlight (WWS) All-Sector Energy Roadmaps for 139 Countries of the World

November 20, 2015

Note: this is a draft – not the final version – modifications are expected

By

Mark Z. Jacobson[1,*], Mark A. Delucchi[2], Zack A.F. Bauer[1], Savannah C. Goodman[1], W.E. Chapman[1], Mary A. Cameron[1], Alphabetical: Cedric Bozonnat[1], Liat Chobadi[3], Jenny R. Erwin[1], Simone N. Fobi[1], Owen K. Goldstrom[1], Sophie H. Harrison[1], Ted M. Kwasnik[1], Jonathan Lo[1], Jingyi Liu[1], Chun J. Yi[1], Sean B. Morris[1], Kevin R. Moy[1], Patrick L. O'Neill[1], Stephanie Redfern[1], Robin Schucker[1], Mike A. Sontag[1], Jingfan Wang[1], Eric Weiner[1], Alex S. Yachanin[1]

[1]*Atmosphere/Energy Program, Dept. of Civil and Env. Engineering, Stanford University*
[*]*Corresponding author. T: 650-723-6836; F: 650-723-7058; E: jacobson@stanford.edu*

[2]*Institute of Transportation Studies, U.C. Berkeley*

[3]*Technical University of Berlin*

Abstract

We develop roadmaps for converting the all-purpose energy (electricity, transportation, heating/cooling, industry, and agriculture/forestry/fishing) infrastructures of each of 139 countries of the world to ones powered by wind, water, and sunlight (WWS). As of the end of 2014, 3.8% of the WWS energy generation capacity needed for a 100% world has already been installed in these countries, with Norway (67%), Paraguay (54%), and Iceland (39%) the furthest along The roadmaps envision 80% conversion by 2030 and 100% conversion of all countries by 2050. The transformation can reduce 2050 power demand relative to BAU by ~32.3% due to the efficiency of electricity over combustion and another ~6.9% due to end-use efficiency beyond that already occurring in the BAU case. Remaining annually averaged 2050 demand may be met with a mean of ~19.4% onshore wind, ~12.9% offshore wind, ~42.2% utility-scale photovoltaic (PV), ~5.6% residential rooftop PV, ~6.0% commercial/government/parking rooftop PV, ~7.7% concentrated solar power (CSP), ~0.74% geothermal power, ~0.72% wave power, ~0.07% tidal power, and ~4.8% hydropower. The new plus existing nameplate capacity of generators across all 139 countries is ~45.0 TW, which represents only ~0.5% of the technically possible installed capacity. An additional ~0.93 TW nameplate capacity of new CSP, ~5.0 TW of new solar thermal for heat, and ~0.07 TW of existing geothermal heat in combination with low-cost storage is estimated necessary to balance supply and demand economically. The capital cost of all new generators (49.2 TW nameplate) is ~$100.1 trillion in 2013 U.S. dollars, or ~$2.0 million/MW. Over the 139 countries, converting will create an estimated 24.0 million 35-

year construction jobs and 26.5 million 35-year operation jobs for the energy facilities alone, the total outweighing the 28.4 million jobs lost by ~22.1 million. Converting will eliminate ~4.6 (1.3-8.0) million premature air pollution mortalities per year today and 3.3 (0.8-7.0) million/yr in 2050 in the 139 countries, avoiding ~$25.4 ($4.3-$69.7) trillion/year in 2050 air-pollution damage costs (2013 dollars), equivalent to ~7.9 (1.3-21.6) percent of the 2050 139-country gross domestic product. It will further eliminate ~$17 (9.6-36) trillion/year in 2050 global warming costs (2013 dollars) due to 139-country emissions. A 2050 WWS versus BAU infrastructure will save the average person worldwide $170/year in fuel costs, ~2,880/year in air-pollution damage costs, and $1,930/year in climate costs (2013 dollars). The new footprint over land required for adding the WWS infrastructure is equivalent to ~0.29% of the 139-country land area, mostly in deserts and barren land, without accounting for land gained from eliminating the current energy infrastructure. The new spacing area between wind turbines, which can be used for farmland, ranchland, grazing land, or open space, is equivalent to 0.65% of the 139-country land area. Aside from virtually eliminating air pollution morbidity and mortality and global warming, the implementation of these roadmaps will create net jobs worldwide, stabilize energy prices because fuel costs are zero, reduce energy poverty and international conflict over energy as countries become energy independent, and reduce risks of large-scale system disruptions by significantly decentralizing power production. The aggressive worldwide conversion to WWS proposed here will avoid exploding CO_2 levels and catastrophic climate change by 2050.

Keywords: Renewable energy; air pollution; global warming; sustainability

1. Introduction

We develop roadmaps for converting the all-purpose energy (electricity, transportation, heating/cooling, industry, and agriculture/forestry/fishing) infrastructures of 139 countries to ones powered by wind, water, and sunlight (WWS). These roadmaps represent high-resolution country-specific WWS plans that improve upon and update the general world roadmap developed by Jacobson and Delucchi (2009, 2011) and Delucchi and Jacobson (2011) and expand upon the individual U.S. state energy roadmaps for New York, California, Washington State, and the 50 United States developed in Jacobson et al. (2013, 2014, 2016a, 2015a), respectively.

The roadmaps here are developed with a consistent methodology across all countries and with the goal of maximizing emission reductions of both health-affecting air pollutants and climate-relevant greenhouse gases and particles while quantifying land use requirements, jobs, and costs. Previous clean-energy plans have generally been limited to individual countries or regions, partial emission reductions and/or selected sectors (e.g., Parsons-Brinckerhoff, 2009 for the UK; Price-Waterhouse-Coopers, 2010 for Europe and North Africa; Beyond Zero Emissions, 2010 for Australia; ECF, 2010 for Europe; EREC, 2010 for Europe; Zero Carbon Britain, 2013 for Great Britain; ELTE/EENA, 2014 for Hungary; Connolly and Mathiesen, 2014 for Ireland; Hooker-Stroud et al., 2015 for the UK; Mahiesen et al., 2015 for Denmark; Negawatt Association, 2015 for France; and Teske et al., 2015 for several world regions).

This paper provides the original country-specific estimates of

(1) future energy demand (load) in the electricity, transportation, heating/cooling, industrial, and agriculture/forestry/fishing sectors in both a business-as-usual (BAU) case and a WWS case;
(2) numbers of total and new WWS generators needed to meet the estimated load in each sector in the WWS case;
(3) footprint and spacing areas needed for the WWS generators;
(4) rooftop areas and solar photovoltaic (PV) installation potentials on residential and commercial/government buildings and associated carports, garages, parking lots, and parking structures;
(5) levelized costs of energy today and in 2050 in the BAU and WWS cases;
(6) reductions in air-pollution mortality and morbidity and associated health costs today and in 2050, accounting for future reductions in emissions in the BAU and WWS cases;
(7) avoided global-warming costs today and in 2050 in the BAU and WWS cases; and
(8) numbers of jobs produced and lost and the resulting revenue changes in the BAU and WWS cases.

This paper further provides a transition timeline, energy efficiency measures, and potential policy measures to implement the roadmaps.

2. WWS Technologies

This study starts with 2012 energy use in each energy sector in each of 139 individual countries for which IEA (2015) energy data are available. It then projects energy use in each sector of each country to 2050. The BAU projections account for some end use energy efficiency improvements and some growth in renewables. Next, all energy-consuming processes in each sector are electrified, and the resulting end-use energy required for a fully electrified all-purpose energy infrastructure is estimated. Some of the end-use electricity in each country is used to produce hydrogen for some transportation and industrial applications. Modest additional end-use energy efficiency improvements are then applied. Finally, the remaining power demand is supplied by a set of wind, water, and solar (WWS) technologies. The mix of WWS technologies varies with each country depending on available resources, rooftop areas, and land/water areas.

The WWS technologies selected to provide the electricity include wind, concentrated solar power (CSP), geothermal, solar PV, tidal, wave, and hydropower. These generators are existing technologies that were found to reduce health and climate impacts the most among multiple technologies while minimizing land and water use and other impacts (Jacobson, 2009).

The technologies selected for ground transportation, which will be entirely electrified, include battery electric vehicles (BEVs) and hydrogen fuel cell (HFC) vehicles, where the hydrogen (referred to here as electrolytic hydrogen) is produced by electrolysis (the splitting of water to produce hydrogen). BEVs with fast charging or battery swapping will dominate long-distance, light-duty ground transportation; battery electric-HFC hybrids will dominate heavy-duty ground transportation and long-distance water-borne shipping; batteries will power short-distance shipping (e.g., ferries); and electrolytic cryogenic hydrogen combined with batteries will power aircraft. We restrict the use of HFCs to transport applications that require more on-board energy storage than can be provided economically by batteries (e.g., long-distance, heavy-load ground transport, shipping, and air transport) because electrolytic HFCs are a relatively inefficient use of primary WWS power. We do not use electrolytic hydrogen or HFCs to generate electricity because, as discussed later, there are more economical ways to balance supply and demand in a 100% WWS system.

Air heating and cooling will be electrified and powered by electric heat pumps (ground-, air-, or water-source) and some electric-resistance heating. Water heat will be generated by heat pumps with electric resistance elements for low temperatures and/or solar hot water preheating. Cook stoves will have either an electric induction or a resistance-heating element.

High-temperature industrial processes will be powered by electric arc furnaces, induction furnaces, dielectric heaters, resistance heaters, and some combusted electrolytic hydrogen.

The roadmaps presented here assume the adoption of new energy-efficiency measures, but they exclude the use of nuclear power, coal with carbon capture, liquid or solid biofuels, or natural gas because all result in more air pollution and climate-relevant emissions than do WWS technologies and have other issues, as discussed in Jacobson and Delucchi (2011) and Jacobson et al. (2013).

This study calculates the number of generators of each type needed to power each country based on the 2050 power demand in the country after all sectors have been electrified but before considering grid reliability and not considering imports/exports of energy. However, it then uses results from a grid reliability study for the continental U.S. (Jacobson et al., 2015b) to estimate the additional generators needed worldwide and by country to ensure a reliable electric power grid while considering that all energy sectors have been electrified with some use of electrolytic hydrogen.

In reality, energy exchanges among countries will occur in 2050 as they currently do. However, we restrict our calculations to assume each country can generate all of its annually averaged power independently of other countries, since ultimately this goal may reduce international conflict. However, because it can be less expensive for countries with higher grade WWS resources to produce more power than they need for their own use and export the rest, the real system cost will likely be less than that proposed here since the costs of, for example solar, are higher in low-sunlight countries than in countries that might export solar electricity. An optimization study will be performed to determine the best tradeoff between generation cost and additional transmission cost, but such an optimization is left for future work.

3. Changes in Each Country's Power Load upon Conversion to WWS

Table 1 summarizes the projected country-specific end-use power demand by sector in 2050 if conventional fuel use continues along a BAU or "conventional energy" trajectory. End-use power is the power in electricity or fuel (e.g., power available in gasoline) that people actually use to provide heating, cooling, lighting, transportation, and so on. Thus, it excludes losses incurred during the production and transmission of the power. Table 1 then shows the new load upon converting the electricity and fuel sources to 100% WWS (zero fossil fuels, biofuels, or nuclear fuels). The table is derived from a spreadsheet analysis of annually averaged end-use load data by sector (Delucchi et al., 2015). All end uses that feasibly can be electrified are assumed to use WWS power directly, and remaining end uses (some transportation and high-temperature industrial processes) are assumed to use WWS power to produce electrolytic hydrogen.

With these roadmaps, electricity generation increases, but the use of oil and gas for transportation, heating/cooling, industry, and agriculture/forestry/fishing decreases to zero. Further, the increase in electricity use due to electrifying all sectors is much less than the decrease in energy in the gas, liquid, and solid fuels that the electricity replaces, because of the high energy-to-work conversion efficiency of electricity used for heating and electric motors. Also, converting eliminates the need for some BAU energy, including that required for coal, oil, gas, biofuels, bioenergy, and uranium mining, transport, and/or refining. As a result, end use load decreases significantly with WWS energy systems in all countries (Table 1).

Table 1. 1st row of each country: estimated 2050 total end-use load (GW) and percent of total load by sector if conventional fossil-fuel, nuclear, and biofuel use continue from today to 2050 under a BAU trajectory. 2nd row of each country: estimated 2050 total end-use load (GW) and percent of total load by sector if 100% of BAU end-use all-purpose delivered load in 2050 is instead provided by WWS. The estimate in the last column "Overall percent change" for each country is the percent reduction in total 2050 BAU load due to switching to WWS, including the effects of assumed policy-based improvements in end-use efficiency beyond those in the BAU case (6.9%), inherent reductions in energy use due to electrification, and the elimination of energy use for the upstream mining, transport, and/or refining of coal, oil, gas, biofuels, bioenergy, and uranium.

Country	Scen-ario	2050 Total end-use load (GW)	Resid-ential per-cent of total	Com-mercial per-cent of total	Indus-trial per-cent of total	Trans-port per-cent of total	Ag/For /Fish-ing per-cent of total	Other percent of total	Overall percent change in end-use power with WWS
Albania	BAU	4.7	24.54	12.44	22.01	37.36	3.39	0.25	
	WWS	2.7	31.99	16.80	25.59	20.18	5.01	0.44	-42.32
Algeria	BAU	105.0	33.10	0.04	37.79	21.87	0.54	6.65	
	WWS	54.5	43.42	0.07	29.86	14.28	0.98	11.39	-48.05
Angola	BAU	21.4	46.85	8.98	21.12	22.85	0.13	0.07	
	WWS	13.7	52.50	10.86	25.31	11.08	0.17	0.09	-35.74
Argentina	BAU	145.4	30.39	9.97	28.51	27.81	3.32	0.00	
	WWS	85.2	35.34	13.46	27.81	18.71	4.68	0.00	-41.37
Armenia	BAU	4.9	32.42	9.82	19.30	26.68	0.57	11.21	
	WWS	3.5	31.83	10.88	20.88	22.68	0.81	12.93	-28.91
Australia	BAU	170.3	10.92	7.48	41.30	33.66	2.03	4.60	
	WWS	89.2	14.97	11.18	41.60	21.80	3.24	7.21	-47.59
Austria	BAU	44.7	22.60	11.28	33.47	23.62	2.08	6.95	
	WWS	29.4	25.88	14.53	34.02	14.25	2.66	8.67	-34.23
Azerbaijan	BAU	20.8	30.53	10.84	24.91	29.67	4.05	0.00	
	WWS	11.2	39.72	15.99	20.03	17.78	6.47	0.00	-46.28
Bahrain	BAU	14.2	9.98	9.26	56.21	24.48	0.07	0.00	

	WWS	6.5	16.66	15.72	50.76	16.70	0.16	0.00	-54.33
Bangladesh	BAU	58.8	45.54	1.22	34.41	11.00	7.51	0.32	
	WWS	42.1	45.00	1.40	38.33	6.04	8.78	0.45	-28.49
Belarus	BAU	56.0	19.66	12.45	29.15	16.75	3.97	18.02	
	WWS	39.3	23.12	15.72	26.39	8.76	4.95	21.05	-29.81
Belgium	BAU	64.6	17.73	12.83	35.17	30.08	1.75	2.45	
	WWS	39.0	20.48	17.02	39.94	16.83	2.37	3.37	-39.58
Benin	BAU	5.7	48.10	10.16	1.12	40.62	0.00	0.00	
	WWS	3.2	61.10	14.59	1.73	22.58	0.00	0.00	-43.95
Bolivia	BAU	12.9	13.72	3.95	37.62	34.28	7.36	3.07	
	WWS	7.6	16.74	5.31	40.91	21.76	10.64	4.63	-41.42
Bosnia and	BAU	7.7	24.32	0.00	30.03	31.64	0.24	13.77	
Herzegovina	WWS	4.6	31.16	0.00	30.38	17.04	0.41	21.00	-41.18
Botswana	BAU	4.8	21.70	8.27	34.76	26.98	1.44	6.86	
	WWS	3.2	23.94	9.68	43.24	12.67	1.95	8.52	-33.69
Brazil	BAU	627.5	9.63	9.13	49.78	26.73	4.52	0.21	
	WWS	389.7	11.53	11.42	52.50	18.01	6.25	0.28	-37.90
Brunei	BAU	6.6	9.11	11.63	60.63	18.62	0.00	0.00	
Darussalam	WWS	2.2	20.01	26.53	36.39	17.07	0.00	0.00	-66.01
Bulgaria	BAU	25.1	20.39	15.53	33.46	29.08	1.54	0.00	
	WWS	15.2	25.75	20.35	33.92	17.81	2.17	0.00	-39.40
Cambodia	BAU	9.3	46.75	4.17	31.64	16.36	0.00	1.08	
	WWS	6.3	49.26	4.74	37.17	7.46	0.00	1.37	-31.68
Cameroon	BAU	11.1	54.59	10.32	17.26	16.96	0.19	0.68	
	WWS	6.9	62.60	13.12	14.66	8.43	0.30	0.89	-37.36
Canada	BAU	412.1	13.93	15.58	53.32	14.83	2.35	0.00	
	WWS	235.1	17.57	21.69	47.52	9.70	3.51	0.00	-42.95
Chile	BAU	76.1	16.05	9.11	50.52	22.94	1.37	0.00	
	WWS	49.5	17.82	10.94	58.04	11.45	1.74	0.00	-35.02
China	BAU	5,044.7	24.62	7.22	41.92	22.21	1.40	2.63	
	WWS	3,252.0	27.93	8.99	45.87	11.54	1.90	3.77	-35.54
Chinese Taipei	BAU	170.0	11.87	9.45	55.37	18.95	1.16	3.20	
	WWS	111.6	13.47	11.22	59.79	9.15	1.57	4.79	-34.34
Colombia	BAU	60.8	18.33	7.73	28.99	39.80	5.04	0.11	
	WWS	32.2	24.52	11.52	31.41	24.39	7.98	0.18	-47.00
Congo	BAU	2.3	39.51	0.81	9.03	45.36	0.00	5.29	
	WWS	1.2	53.51	1.24	10.54	26.55	0.00	8.16	-46.79
Congo, Dem.	BAU	42.4	56.80	0.25	39.57	3.04	0.00	0.34	
Republic of	WWS	31.1	54.89	0.26	43.18	1.29	0.00	0.38	-26.58
Costa Rica	BAU	7.4	13.62	12.58	20.90	50.92	1.48	0.49	
	WWS	4.0	18.81	17.98	30.79	29.17	2.46	0.79	-45.61
Cote d'Ivoire	BAU	12.2	58.09	12.09	15.36	12.18	2.27	0.00	
	WWS	8.3	61.70	14.20	15.76	5.59	2.75	0.00	-32.13
Croatia	BAU	15.6	25.14	17.52	25.09	29.61	2.64	0.00	
	WWS	9.2	31.85	23.64	24.11	16.68	3.72	0.00	-41.30
Cuba	BAU	14.5	15.45	5.01	59.07	13.91	1.71	4.85	
	WWS	10.2	16.37	5.54	63.86	6.46	2.09	5.68	-29.86
Cyprus	BAU	4.7	14.76	18.16	7.58	56.99	1.79	0.72	
	WWS	2.4	21.43	27.48	11.03	35.66	3.07	1.33	-48.69
Czech Republic	BAU	38.6	24.75	15.38	36.87	19.47	2.47	1.07	
	WWS	25.4	27.49	19.41	37.02	11.37	3.18	1.53	-34.25
Denmark	BAU	24.3	29.20	15.59	22.34	26.91	5.90	0.07	
	WWS	15.7	37.52	20.91	19.14	14.49	7.86	0.09	-35.43
Dominican	BAU	11.4	15.90	5.21	24.14	51.86	2.89	0.00	
Republic	WWS	6.2	21.52	7.48	35.85	29.91	5.24	0.00	-45.98
Ecuador	BAU	24.0	11.31	4.52	26.03	55.66	0.73	1.74	
	WWS	10.8	18.29	7.81	30.32	38.69	1.34	3.55	-55.11
Egypt	BAU	173.3	22.22	9.86	41.51	19.68	5.23	1.50	
	WWS	102.9	27.46	12.89	39.29	10.74	7.56	2.07	-40.64
El Salvador	BAU	5.2	22.18	3.64	24.13	47.93	0.25	1.87	

	WWS	2.8	29.35	5.17	34.40	27.23	0.45	3.40	-45.16
Eritrea	BAU	0.8	73.64	9.41	5.49	11.47	0.00	0.00	
	WWS	0.6	77.74	10.93	6.09	5.25	0.00	0.00	-31.93
Estonia	BAU	5.2	29.38	15.55	23.45	27.98	3.65	0.00	
	WWS	3.3	38.24	20.55	22.21	14.14	4.87	0.00	-36.46
Ethiopia	BAU	53.3	86.38	1.96	6.12	4.48	0.52	0.53	
	WWS	37.7	87.50	2.20	7.09	1.98	0.60	0.62	-29.32
Finland	BAU	39.8	22.19	9.44	44.71	15.23	2.99	5.44	
	WWS	28.7	25.41	10.18	45.99	7.71	3.54	7.17	-27.87
France	BAU	242.5	27.72	17.72	22.97	27.38	2.95	1.26	
	WWS	155.3	31.30	22.12	24.09	16.88	3.89	1.72	-35.93
Gabon	BAU	4.5	38.73	3.97	39.16	16.74	0.77	0.63	
	WWS	3.0	41.58	4.57	44.26	7.73	0.94	0.93	-32.51
Georgia	BAU	7.2	31.97	8.93	25.14	28.78	4.35	0.84	
	WWS	4.5	36.66	11.38	28.75	16.03	6.07	1.10	-37.95
Germany	BAU	375.8	23.56	15.35	28.68	32.34	0.00	0.08	
	WWS	258.3	24.55	18.03	28.53	28.80	0.00	0.09	-31.28
Ghana	BAU	15.1	30.11	6.00	32.00	29.58	2.32	0.00	
	WWS	9.6	34.50	7.39	40.59	14.53	3.00	0.00	-36.60
Gibraltar	BAU	3.3	0.00	0.00	0.13	99.28	0.00	0.58	
	WWS	1.1	0.00	0.00	0.30	97.85	0.00	1.84	-68.39
Greece	BAU	30.9	23.56	12.63	26.07	33.62	1.57	2.56	
	WWS	16.9	31.45	18.01	23.99	19.99	2.73	3.83	-45.34
Guatemala	BAU	14.5	52.29	5.11	9.65	32.59	0.00	0.35	
	WWS	8.6	63.14	6.77	12.53	17.07	0.00	0.49	-40.54
Haiti	BAU	4.4	71.55	2.15	8.03	18.28	0.00	0.00	
	WWS	2.9	78.72	2.65	9.88	8.75	0.00	0.00	-34.95
Honduras	BAU	7.7	34.91	6.70	23.28	31.66	0.00	3.45	
	WWS	4.8	40.95	8.43	30.04	15.99	0.00	4.58	-38.34
Hong Kong,	BAU	59.5	7.87	23.64	12.50	55.92	0.00	0.08	
China	WWS	30.6	10.40	35.72	19.80	33.94	0.00	0.14	-48.50
Hungary	BAU	24.5	34.45	21.67	21.26	19.93	2.69	0.00	
	WWS	15.9	38.07	27.24	19.98	11.19	3.51	0.00	-35.07
Iceland	BAU	4.4	16.11	11.80	48.18	13.20	10.44	0.27	
	WWS	3.4	17.34	12.60	52.95	5.41	11.34	0.35	-22.05
India	BAU	1,607.8	24.07	5.26	26.99	38.96	3.27	1.45	
	WWS	921.9	30.05	7.24	33.25	21.92	5.28	2.27	-42.66
Indonesia	BAU	380.4	25.69	5.81	41.51	24.34	2.40	0.26	
	WWS	227.1	31.25	7.56	44.49	13.04	3.30	0.36	-40.30
Iran, Islamic	BAU	380.4	21.36	6.76	43.26	23.78	4.63	0.21	
Republic of	WWS	227.0	24.34	9.13	44.46	14.81	6.91	0.35	-40.32
Iraq	BAU	53.1	13.18	1.38	27.12	48.82	0.00	9.49	
	WWS	27.5	18.37	2.06	31.96	29.33	0.00	18.29	-48.14
Ireland	BAU	15.4	24.05	14.90	25.59	32.74	2.72	0.00	
	WWS	9.2	26.18	19.85	32.15	17.94	3.88	0.00	-40.37
Israel	BAU	27.0	18.58	12.47	18.82	24.93	0.90	24.30	
	WWS	16.8	22.13	15.53	13.56	12.48	1.44	34.86	-37.75
Italy	BAU	215.0	23.89	14.60	27.01	32.26	2.11	0.13	
	WWS	140.9	25.50	17.85	26.64	27.11	2.74	0.17	-34.49
Jamaica	BAU	4.1	12.55	8.67	32.51	43.83	2.35	0.09	
	WWS	2.4	15.86	11.60	45.49	23.54	3.35	0.15	-41.99
Japan	BAU	365.1	17.88	26.15	33.33	21.87	0.59	0.17	
	WWS	234.0	20.44	32.33	34.58	11.61	0.76	0.27	-35.91
Jordan	BAU	11.7	16.98	8.32	21.92	45.52	3.62	3.65	
	WWS	6.2	23.84	12.23	24.58	26.84	6.84	5.67	-47.16
Kazakhstan	BAU	141.9	8.40	4.71	72.59	8.85	1.22	4.23	
	WWS	71.5	12.69	8.15	63.57	6.02	2.10	7.47	-49.60
Kenya	BAU	22.9	63.74	2.20	15.74	17.47	0.26	0.59	
	WWS	15.2	69.19	2.58	18.95	8.24	0.32	0.73	-33.91
Korea, Dem.	BAU	38.4	0.16	0.00	66.39	2.34	0.00	31.11	

People's Rep.	WWS	30.7	0.14	0.00	65.93	0.91	0.00	33.02	-19.96
Korea,	BAU	295.6	14.18	20.92	40.70	22.31	1.23	0.67	
Republic of	WWS	192.3	15.88	25.54	44.27	11.75	1.71	0.84	-34.92
Kosovo	BAU	3.1	38.03	10.93	24.00	25.72	1.31	0.00	
	WWS	1.9	45.17	13.75	26.24	12.94	1.89	0.00	-38.09
Kuwait	BAU	57.2	9.89	7.05	61.59	21.47	0.00	0.00	
	WWS	22.5	19.24	13.91	49.84	17.01	0.00	0.00	-60.69
Kyrgyzstan	BAU	9.2	22.42	10.54	18.42	34.86	1.92	11.84	
	WWS	5.7	29.05	13.70	21.30	17.55	2.68	15.72	-38.11
Latvia	BAU	9.9	25.15	19.64	22.17	30.27	2.74	0.02	
	WWS	6.5	31.07	24.83	25.39	15.15	3.54	0.02	-34.35
Lebanon	BAU	9.0	23.46	7.32	16.07	46.45	0.00	6.70	
	WWS	5.2	29.79	9.85	23.76	25.10	0.00	11.49	-42.34
Libya	BAU	27.2	12.05	10.02	19.75	39.42	1.64	17.11	
	WWS	16.2	14.89	13.07	19.84	20.65	2.76	28.78	-40.54
Lithuania	BAU	12.9	22.54	16.08	29.43	30.17	1.74	0.04	
	WWS	7.9	30.06	22.21	28.05	17.17	2.45	0.05	-39.06
Luxembourg	BAU	5.8	10.91	17.55	16.45	54.36	0.72	0.00	
	WWS	3.1	14.17	26.90	24.24	33.55	1.15	0.00	-46.56
Macedonia,	BAU	4.9	26.21	15.24	32.50	22.49	1.13	2.43	
Republic of	WWS	3.3	30.31	18.09	36.55	10.63	1.42	3.00	-33.51
Malaysia	BAU	141.9	8.65	13.80	52.66	24.81	0.08	0.00	
	WWS	77.7	11.85	19.57	53.87	14.57	0.15	0.00	-45.27
Malta	BAU	4.1	4.82	5.99	3.30	85.43	0.06	0.41	
	WWS	1.6	9.67	12.30	6.32	70.50	0.15	1.05	-62.25
Mexico	BAU	400.4	10.65	4.25	51.23	29.17	3.65	1.05	
	WWS	194.2	16.06	6.82	49.48	18.97	6.52	2.16	-51.50
Moldova,	BAU	5.0	32.88	16.07	31.42	17.06	1.78	0.80	
Republic of	WWS	3.5	34.58	19.14	35.21	7.83	2.14	1.09	-29.82
Mongolia	BAU	9.2	25.76	8.32	39.56	15.06	2.82	8.49	
	WWS	6.8	28.30	11.18	41.10	6.40	3.17	9.86	-25.86
Montenegro	BAU	1.6	36.18	1.35	29.81	31.39	0.47	0.81	
	WWS	1.0	42.48	1.68	38.61	15.55	0.64	1.04	-36.54
Morocco	BAU	37.5	18.35	9.16	32.38	25.17	14.93	0.00	
	WWS	24.2	20.86	11.18	36.27	12.40	19.29	0.00	-35.50
Mozambique	BAU	14.2	50.07	1.24	40.08	8.43	0.18	0.00	
	WWS	10.4	49.24	1.32	45.63	3.62	0.20	0.00	-26.90
Myanmar	BAU	26.5	56.81	2.87	25.29	8.06	1.19	5.79	
	WWS	18.4	58.71	3.20	25.65	4.16	1.40	6.88	-30.34
Namibia	BAU	3.9	7.06	0.11	14.02	28.00	22.72	28.09	
	WWS	2.8	7.08	0.12	16.59	12.23	26.13	37.85	-28.69
Nepal	BAU	16.0	71.92	2.98	11.72	10.44	2.82	0.12	
	WWS	11.1	74.55	3.37	13.83	4.71	3.38	0.17	-30.82
Netherlands	BAU	105.2	16.90	16.12	29.54	32.62	4.83	0.00	
	WWS	60.2	20.53	23.00	30.61	18.62	7.25	0.00	-42.75
Netherlands	BAU	7.8	1.24	0.00	19.36	78.49	0.00	0.91	
Antilles	WWS	2.4	2.82	0.00	13.24	80.92	0.00	3.02	-69.78
New Zealand	BAU	23.7	10.35	8.66	37.64	38.63	4.28	0.44	
	WWS	13.5	13.45	11.88	46.31	21.12	6.48	0.77	-42.73
Nicaragua	BAU	3.8	37.16	9.72	16.37	34.56	2.13	0.05	
	WWS	2.2	45.62	12.94	19.97	18.33	3.08	0.07	-41.27
Nigeria	BAU	207.1	60.21	3.53	25.21	7.76	0.01	3.28	
	WWS	133.1	67.21	4.39	20.44	3.76	0.01	4.18	-35.72
Norway	BAU	37.0	19.74	14.55	46.24	17.61	1.45	0.41	
	WWS	20.7	27.01	20.75	38.28	11.00	2.36	0.60	-44.15
Oman	BAU	55.2	4.07	3.78	74.11	15.27	0.11	2.66	
	WWS	34.0	5.05	4.77	78.72	7.73	0.17	3.55	-38.50
Pakistan	BAU	169.8	44.79	4.88	33.91	14.93	1.31	0.17	
	WWS	116.4	45.98	5.65	38.39	7.89	1.89	0.21	-31.42
Panama	BAU	14.5	7.39	7.89	11.36	73.18	0.17	0.00	

	WWS	6.3	12.40	14.01	21.10	52.18	0.32	0.00	-56.31
Paraguay	BAU	8.7	23.98	8.51	28.03	39.49	0.00	0.00	
	WWS	5.2	29.40	11.04	36.73	22.82	0.00	0.00	-40.25
Peru	BAU	35.4	15.67	7.04	28.96	46.78	1.55	0.00	
	WWS	18.7	21.58	10.43	33.84	31.62	2.52	0.00	-47.18
Philippines	BAU	67.7	19.12	15.49	34.55	29.25	1.59	0.00	
	WWS	42.0	22.82	19.40	39.91	15.58	2.28	0.00	-37.94
Poland	BAU	99.3	26.83	15.08	31.08	21.18	5.84	0.00	
	WWS	60.5	29.43	20.22	29.55	12.88	7.92	0.00	-39.03
Portugal	BAU	24.4	17.30	7.56	37.66	35.08	2.25	0.15	
	WWS	14.2	21.75	10.68	43.29	20.76	3.31	0.21	-41.66
Qatar	BAU	71.7	2.89	1.69	78.15	15.17	0.00	2.12	
	WWS	22.4	7.04	4.18	66.92	15.10	0.00	6.77	-68.71
Romania	BAU	56.1	27.42	10.66	37.11	22.14	1.72	0.94	
	WWS	34.5	33.20	14.21	36.21	12.71	2.42	1.26	-38.55
Russian Federation	BAU	864.1	24.67	7.13	43.31	22.75	2.12	0.01	
	WWS	574.3	31.45	8.48	39.32	17.74	2.99	0.01	-33.54
Saudi Arabia	BAU	232.4	11.63	9.23	39.62	39.08	0.39	0.05	
	WWS	121.6	16.96	13.68	45.25	23.27	0.75	0.09	-47.68
Senegal	BAU	5.9	39.68	8.28	22.71	28.43	0.42	0.48	
	WWS	3.7	45.82	10.27	28.45	14.17	0.67	0.63	-37.47
Serbia	BAU	20.8	32.94	13.13	32.20	20.06	1.67	0.00	
	WWS	13.6	38.25	16.07	33.50	10.01	2.17	0.00	-34.49
Singapore	BAU	142.2	1.85	5.84	19.44	72.78	0.00	0.10	
	WWS	57.2	3.47	11.27	28.37	56.63	0.00	0.25	-59.76
Slovak Republic	BAU	16.5	21.46	16.69	42.87	17.56	1.42	0.00	
	WWS	10.5	25.62	21.58	39.81	11.08	1.90	0.00	-36.55
Slovenia	BAU	7.2	24.45	11.76	27.98	33.37	1.85	0.58	
	WWS	4.5	29.05	15.04	34.69	18.04	2.42	0.76	-37.37
South Africa	BAU	236.5	16.67	8.28	54.24	15.52	2.52	2.77	
	WWS	130.8	16.20	11.79	54.51	9.28	3.97	4.25	-44.71
Spain	BAU	147.1	16.94	13.20	31.65	34.43	3.04	0.75	
	WWS	82.7	21.77	18.42	32.07	22.00	4.54	1.20	-43.75
Sri Lanka	BAU	22.1	30.73	7.06	30.88	28.57	0.05	2.71	
	WWS	14.1	35.08	8.68	38.69	14.00	0.06	3.49	-36.41
Sudan	BAU	21.6	37.67	14.98	19.89	24.94	1.51	1.00	
	WWS	14.0	42.19	18.55	23.91	12.02	2.07	1.26	-35.34
Sweden	BAU	53.7	23.89	16.50	35.63	22.76	1.22	0.00	
	WWS	37.6	28.80	19.84	37.38	12.49	1.49	0.00	-30.01
Switzerland	BAU	31.2	27.79	18.75	21.32	30.12	1.24	0.78	
	WWS	19.8	31.65	23.52	25.12	16.98	1.71	1.01	-36.59
Syrian Arab Republic	BAU	21.7	15.27	4.85	37.25	34.35	4.63	3.66	
	WWS	12.5	19.71	6.56	42.50	18.65	6.61	5.96	-42.63
Tajikistan	BAU	5.1	14.67	7.80	26.02	6.57	15.34	29.60	
	WWS	4.2	13.73	7.38	27.60	2.86	18.72	29.71	-18.03
Tanzania, United	BAU	35.0	52.24	1.49	25.01	8.72	7.51	5.03	
	WWS	25.1	52.24	1.61	27.96	3.79	8.63	5.78	-28.26
Republic of Thailand	BAU	249.8	10.11	11.31	51.70	21.27	5.47	0.13	
	WWS	151.8	12.29	14.44	53.03	12.63	7.39	0.22	-39.23
Togo	BAU	3.3	57.64	8.79	6.79	26.25	0.00	0.52	
	WWS	2.1	65.96	11.32	8.88	13.00	0.00	0.83	-37.10
Trinidad and Tobago	BAU	16.5	6.90	1.51	70.04	21.55	0.00	0.00	
	WWS	6.8	12.32	2.86	68.38	16.44	0.00	0.00	-59.18
Tunisia	BAU	22.0	20.99	16.03	37.42	19.63	5.92	0.00	
	WWS	14.6	22.76	19.23	39.54	10.82	7.66	0.00	-33.63
Turkey	BAU	124.3	23.91	13.68	36.89	18.06	6.33	1.12	
	WWS	80.0	22.96	16.97	41.32	9.09	8.23	1.43	-35.63
Turkmenistan	BAU	45.6	1.24	41.77	22.14	15.76	1.37	17.72	
	WWS	31.2	1.40	50.80	12.25	11.92	2.00	21.63	-31.70
Ukraine	BAU	174.6	29.62	9.84	42.74	15.36	2.44	0.00	

	WWS	119.1	32.28	12.47	42.43	9.66	3.16	0.00	-31.81
United Arab	BAU	176.0	4.14	5.46	56.07	32.78	0.00	1.56	
Emirates	WWS	110.7	5.04	6.73	69.55	16.23	0.00	2.45	-37.11
United Kingdom	BAU	225.1	29.88	14.15	25.92	28.60	0.60	0.85	
	WWS	127.9	36.22	19.98	24.95	16.70	0.94	1.22	-43.18
United States of	BAU	2,310.3	16.44	14.83	28.24	38.42	1.25	0.82	
America	WWS	1,296.4	21.33	21.02	28.22	26.10	1.88	1.45	-43.89
Uruguay	BAU	8.0	16.22	11.11	30.33	40.49	1.66	0.18	
	WWS	4.7	20.79	14.95	38.86	22.54	2.55	0.31	-42.00
Uzbekistan	BAU	81.6	39.42	11.10	28.09	8.54	4.99	7.86	
	WWS	57.7	37.29	12.93	25.90	6.39	6.69	10.80	-29.38
Venezuela	BAU	121.9	8.87	6.05	50.76	34.27	0.06	0.00	
	WWS	61.6	12.59	9.36	56.75	21.17	0.12	0.00	-49.44
Vietnam	BAU	133.1	23.66	5.23	50.07	19.24	1.80	0.00	
	WWS	91.6	23.60	5.97	59.51	8.71	2.21	0.00	-31.18
Yemen	BAU	12.8	9.39	1.37	27.37	33.32	19.55	9.00	
	WWS	7.5	11.64	1.81	28.25	17.77	27.44	13.08	-41.59
Zambia	BAU	14.0	52.30	2.60	38.82	4.48	1.07	0.73	
	WWS	10.4	51.11	2.72	42.07	1.93	1.29	0.88	-25.95
Zimbabwe	BAU	17.2	50.91	7.95	18.21	4.58	16.99	1.35	
	WWS	12.7	49.75	8.58	19.17	1.88	19.09	1.53	-26.14
All countries	**BAU**	**19,399.8**	**21.64**	**9.66**	**37.97**	**27.01**	**2.06**	**1.66**	
	WWS	**11,796.7**	**25.90**	**12.66**	**39.96**	**16.06**	**2.96**	**2.47**	**-39.19**

BAU values are extrapolated from IEA (2015) data for 2012 to 2050 as follows: EIA's International Energy Outlook (IEO) projects energy use by end-use sector, fuel, and world region out to 2040 (EIA, 2015). This was extended to 2075 using a ten-year moving linear extrapolation. EIA sectors and fuels were then mapped to IEA sectors and fuels, and each country's 2012 energy consumption by sector and fuel was scaled by the ratio of EIA's 2050/2012 energy consumption by sector and fuel for each region. The transportation load includes, among other loads, energy produced in each country for international transportation and shipping. 2050 WWS values are estimated from 2050 BAU values assuming electrification of end-uses and effects of additional energy-efficiency measures. See Delucchi et al. (2015) for details.

In 2012, the 139-country all-purpose, end-use load was ~11.95 TW (terawatts, or trillion watts). Of this, 2.4 TW (20.1%) was electric power load. If the countries follow the BAU trajectory, which involves increasing load, modest shifts in the power sector away from coal toward natural gas, biofuels, bioenergy and some WWS, and modest end-use energy efficiency improvements, their summed all-purpose end-use load is expected to grow to 19.4 TW in 2050 (Table 1).

A conversion to WWS by 2050 is calculated here to reduce the 139-country end-use load and the power required to meet that load by ~39.2% to 11.8 TW (Table 1), with the greatest percentage reduction in the transportation sector. About 6.9 percentage points of this reduction is due to end-use energy efficiency measures beyond those in the BAU scenario and another small portion is due to the fact that conversion to WWS eliminates the need for energy use in coal, oil, gas, biofuels, bioenergy, and uranium mining, transport, and/or refining. The remaining and major reason for the reduction is that the use of electricity for heating and electric motors is more efficient than is fuel combustion for the same applications (Jacobson and Delucchi, 2011). Also, the use of WWS electricity to produce hydrogen for fuel cell vehicles, while less efficient than is the use of WWS electricity to run BEVs, is more efficient and cleaner than is burning liquid fossil fuels for vehicles (Jacobson et al., 2005; Jacobson and Delucchi, 2011). Burning electrolytic hydrogen is slightly less efficient but cleaner than is burning fossil fuels for direct heating, and this is accounted for in Table 1. In the table ~9.1% of all 2050 WWS electricity (44.5% of the transportation load and 4.8% of the industrial load) is for producing, storing, and using hydrogen for long distance and heavy transportation and high-temperature industrial processes.

The percent decrease in load upon conversion to WWS in Table 1 is greater in some countries than in others. The reason is that efficiency gains from electrifying transportation are much greater than are efficiency gains from electrifying other sectors, and the transportation-energy share of total energy is greater in some countries than in others.

4. Numbers of Electric Power Generators Needed and Land-Use Implications

Table 2 summarizes the number of WWS power plants or devices needed to power the sum of all 139 countries in 2050 for all purposes assuming end use power requirements in Table 1 when the percent mixes of end-use power generation by country in Table 3 are used. Table 2 accounts for power losses during transmission and distribution of energy, maintenance of devices, and competition among wind turbines for limited kinetic energy (array losses).

Table 2. Number, capacity, footprint area, and spacing area of WWS power plants or devices needed to provide total annually averaged end-use all-purpose load over all 139 countries examined. Delucchi et al. (2015) derive individual tables for each country.

Energy Technology	Rated power one plant or device (MW)	[a]Percent of 2050 all-purpose load met by plant/device	Name-plate capacity, existing plus new plants or devices (GW)	Percent name-plate capacity already installed 2014	Number of new plants or devices needed for 139 countries	[b]Percent of 139-country land area for footprint of new plants or devices	Percent of 139-country area for spacing of new plants or devices
Annual power							
Onshore wind	5	19.37	6,219	5.83	1,171,330	0.000012	0.65235
Offshore wind	5	12.90	3,820	0.23	762,221	0.000008	0.42451
Wave device	0.75	0.72	372	0.00	495,917	0.000217	0.00000
Geothermal plant	100	0.74	97	13.03	840	0.000241	0.00000
Hydropower plant [c]	1300	4.84	1,143	100.00	0	0.000000	0.00000
Tidal turbine	1	0.068	33	1.64	32,071	0.000008	0.00010
Res. roof PV	0.005	5.55	3,305	1.20	653,034,835	0.014280	0.00000
Com/gov roof PV [d]	0.1	5.97	3,590	1.66	35,302,712	0.015440	0.00000
Solar PV plant [d]	50	42.17	24,917	0.30	496,850	0.218484	0.00000
Utility CSP plant [d]	100	7.67	1,550	0.37	15,446	0.037862	0.00000
Total for annual power		**100.00**	**45,046**	**3.79**	**691,312,222**	**0.287**	**1.077**
New land annual power[e]						0.257	0.652

For peaking/storage							
Additional CSP [f]	100	4.60%	930	0.00	9,302	0.022801	0.000
Solar thermal [f]	50		5,004	0.64	99,436	0.005932	0.000
Geothermal heat [f]	50		70	100.00	0	0.000000	0.000
Total all			**51,050**	**3.54**	**691,420,960**	**0.315**	**1.077**
Total new land[e]						**0.285**	**0.652**

The total number of each device is the sum among all countries. The number of devices in each country is the end use load in 2050 in each country to be supplied by WWS (Table 1) multiplied by the fraction of load satisfied by each WWS device in each country (Table 3) and divided by the annual power output from each device. The annual output by device equals the rated power (this table; same for all countries) multiplied by the country-specific annual capacity factor of the device, diminished by transmission, distribution, maintenance, and array losses. The capacity factors, given in Delucchi et al. (2015), before transmission, distribution, and maintenance losses for onshore and offshore wind turbines at 100-m hub height in 2050, are calculated country by country from global model simulations of winds and wind power (Figure 3), accounting for competition among wind turbines for available kinetic energy based on the approximate number of turbines needed per country as determined iteratively from Tables 2 and 3. Wind array losses due to competition among turbines for the same energy are calculated here to be ~8.5%. The 2050 139-country mean onshore wind capacity factor calculated in this manner after transmission, distribution, maintenance, and array losses is 37.0%. That for offshore wind is ~40.1%. Short- and moderate distance transmission, distribution, and maintenance losses for all energy sources treated here, except rooftop PV, are assumed to be 5-10%. Rooftop PV losses are assumed to be 1-2%. The plans assume 38 (30-45)% of onshore wind and solar and 20 (15-25)% of offshore wind is subject to long-distance transmission with line lengths of 1400 (1200-1600) km and 120 (80-160) km, respectively. Line losses are 4 (3-5)% per 1000 km plus 1.5 (1.3-1.8)% of power in the station equipment. Footprint and spacing areas are calculated from the spreadsheets in Delucchi et al. (2015). Footprint is the area on the top surface of soil covered by an energy technology, thus does not include underground structures.

[a]Total end-use power demand in 2050 with 100% WWS is estimated from Table 1.

[b]Total land area for each country is given in Delucchi et al. (2015). 139-country land area is 119,725,384 km^2. The world land area is 510,072,000 km^2.

[c]The average capacity factors of hydropower plants are assumed to increase from their current values to 50.0%, except for Tajikistan and Paraguay, which are assumed to increase to 40% (see text).

[d]The solar PV panels used for this calculation are Sun Power E20 panels. CSP plant characteristics are patterned after the Ivanpah facility but assuming storage, namely a maximum charge to discharge rate (storage size to generator size ratio) of 2.62:1. The capacity factors used for residential PV, commercial/government rooftop PV, utility scale PV, and CSP are calculated here country-by-country with the 3-D global model simulations also used to calculate solar resource analysis (Figure 5), and are given in Delucchi et al. (2015). For utility solar PV plants, nominal "spacing" between panels is included in the plant footprint area.

[e]The footprint area requiring new land equals the sum of the footprint areas for new onshore wind, geothermal, hydropower, and utility solar PV. Offshore wind, wave and tidal are in water so do not require new land. Similarly, rooftop solar PV does not use new land because the rooftops already exist. Only onshore wind requires new land for spacing area. Spacing area is for onshore and offshore wind is calculated as $42D^2$, where D=rotor diameter. The 5-MW Senvion (RePower) turbine assumed has D=126 m.

The other energy sources either are in water or on rooftops, or do not use new land for spacing. Note that the spacing area for onshore wind can be used for multiple purposes, such as open space, agriculture, grazing, etc.

[f]The installed capacities for peaking power/storage are estimated based on data from Jacobson et al. (2015b). Additional CSP is CSP plus storage beyond that needed for annual power generation to firm the grid across all countries. Additional solar thermal and geothermal are used for soil heat storage. Other types of storage are also used in Jacobson et al. (2015b).

Rooftop PV in Table 2 is divided into residential (5-kW systems on average) and commercial/government (100-kW systems on average). Rooftop PV can be placed on existing rooftops or on elevated canopies above parking lots, highways, and structures without taking up additional undeveloped land. Table 4 summarizes projected 2050 rooftop areas by country usable for solar PV on residential and commercial/government buildings, carports, garages, parking structures, and parking lot canopies. The rooftop areas in Table 4 are used to calculate potential rooftop generation, which in turn limits the penetration of PV on residential and commercial/government buildings in Table 3. Utility-scale PV power plants are sized, on average, relatively small (50 MW) to allow them to be placed optimally in available locations. While utility-scale PV can operate in any country because it can take advantage of both direct and diffuse solar radiation, CSP is assumed to be viable only in countries with significant direct solar radiation, and its penetration in each country is limited to less than its technical potential.

Onshore wind is available to some extent in every country but assumed to be viable in high penetrations primarily in countries with good wind resources (Section 5.1). Offshore wind is assumed to be viable in any country with either ocean or lake coastline (Section 5.1). Wind and solar are the only two sources of electric power with sufficient resource to power the world independently on their own. Averaged over the 139 countries, wind (~32.3%) and solar (61.4%) are the largest generators of annually averaged end-use electric power under these plans. The ratio of wind to solar end-use power is 0.53:1.

Under the roadmaps, the 2050 nameplate capacity of hydropower in each country is assumed to be exactly the same as in 2014. However, existing dams in most countries are assumed to run more efficiently for producing peaking power, thus the capacity factor of dams is assumed to increase (Section 5.4). Geothermal, tidal, and wave energy expansions are limited in each country by their technical potentials (Sections 5.3 and 5.5).

Table 2 indicates that 3.8% of the summed nameplate capacity required for a 100% WWS system for 2050 all-purpose energy in the 139 countries is already installed as of the end of 2014. Figure 1 shows that the countries closest to 100% 2050 all-purpose WWS power as of the end of 2014 are Norway (67%), Paraguay (54%), and Iceland (39%), Tajikistan (34%), Portugal (26%), Sweden (21%), and Switzerland (20.6%). The United States (4.2%) ranks 56^{th} and China (3.4%) ranks 65^{th}.

Figure 1. Countries ranked in order of how close they are at the end of 2014 to reaching 100% WWS power for all purposes in 2050. The percentages are of 2050 WWS installed capacity (summed over all WWS technologies) needed that are already installed..

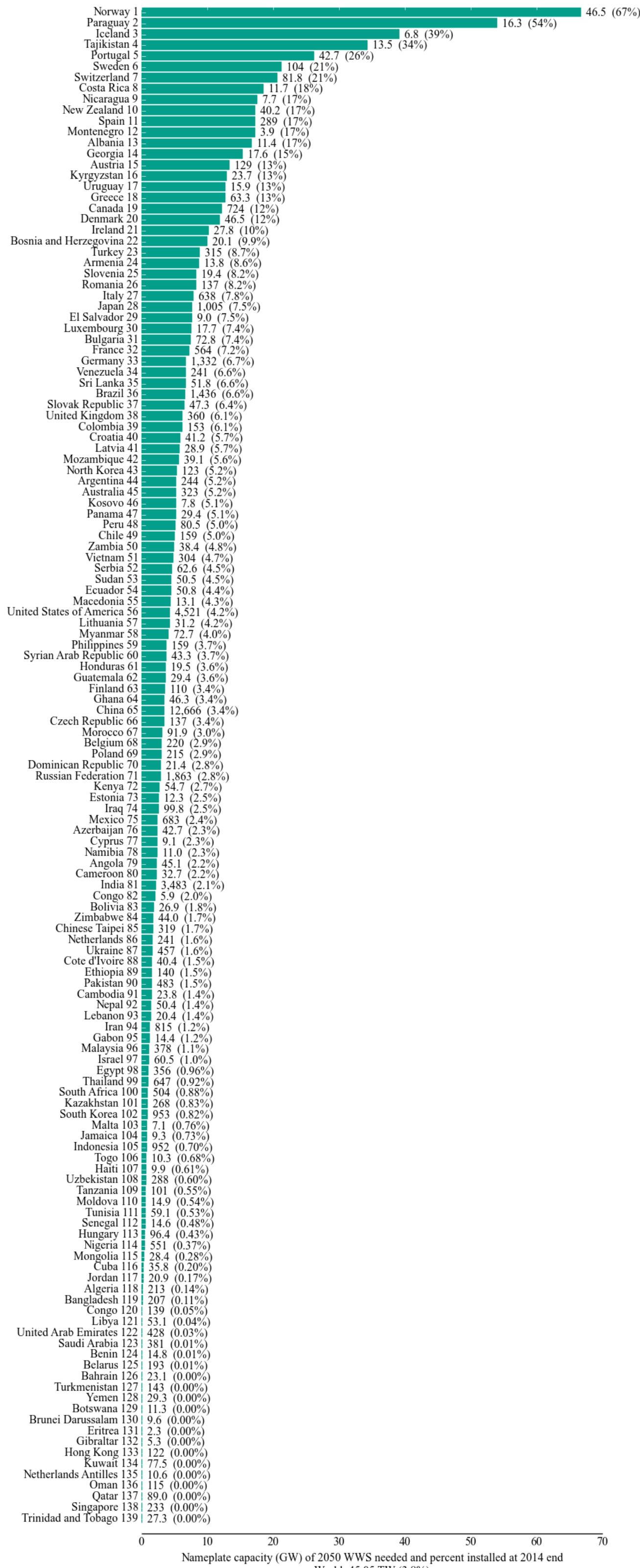

Norway 1 46.5 (67%)
Paraguay 2 16.3 (54%)
Iceland 3 6.8 (39%)
Tajikistan 4 13.5 (34%)
Portugal 5 42.7 (26%)
Sweden 6 104 (21%)
Switzerland 7 81.8 (21%)
Costa Rica 8 11.7 (18%)
Nicaragua 9 7.7 (17%)
New Zealand 10 40.2 (17%)
Spain 11 289 (17%)
Montenegro 12 3.9 (17%)
Albania 13 11.4 (17%)
Georgia 14 17.6 (15%)
Austria 15 129 (13%)
Kyrgyzstan 16 23.7 (13%)
Uruguay 17 15.9 (13%)
Greece 18 63.3 (13%)
Canada 19 724 (12%)
Denmark 20 46.5 (12%)
Ireland 21 27.8 (10%)
Bosnia and Herzegovina 22 20.1 (9.9%)
Turkey 23 315 (8.7%)
Armenia 24 13.8 (8.6%)
Slovenia 25 19.4 (8.2%)
Romania 26 137 (8.2%)
Italy 27 638 (7.8%)
Japan 28 1,005 (7.5%)
El Salvador 29 9.0 (7.5%)
Luxembourg 30 17.7 (7.4%)
Bulgaria 31 72.8 (7.4%)
France 32 564 (7.2%)
Germany 33 1,332 (6.7%)
Venezuela 34 241 (6.6%)
Sri Lanka 35 51.8 (6.6%)
Brazil 36 1,436 (6.6%)
Slovak Republic 37 47.3 (6.4%)
United Kingdom 38 360 (6.1%)
Colombia 39 153 (6.1%)
Croatia 40 41.2 (5.7%)
Latvia 41 28.9 (5.7%)
Mozambique 42 39.1 (5.6%)
North Korea 43 123 (5.2%)
Argentina 44 244 (5.2%)
Australia 45 323 (5.2%)
Kosovo 46 7.8 (5.1%)
Panama 47 29.4 (5.1%)
Peru 48 80.5 (5.0%)
Chile 49 159 (5.0%)
Zambia 50 38.4 (4.8%)
Vietnam 51 304 (4.7%)
Serbia 52 62.6 (4.5%)
Sudan 53 50.5 (4.5%)
Ecuador 54 50.8 (4.4%)
Macedonia 55 13.1 (4.3%)
United States of America 56 4,521 (4.2%)
Lithuania 57 31.2 (4.2%)
Myanmar 58 72.7 (4.0%)
Philippines 59 159 (3.7%)
Syrian Arab Republic 60 43.3 (3.7%)
Honduras 61 19.5 (3.6%)
Guatemala 62 29.4 (3.6%)
Finland 63 110 (3.4%)
Ghana 64 46.3 (3.4%)
China 65 12,666 (3.4%)
Czech Republic 66 137 (3.4%)
Morocco 67 91.9 (3.0%)
Belgium 68 220 (2.9%)
Poland 69 215 (2.9%)
Dominican Republic 70 21.4 (2.8%)
Russian Federation 71 1,863 (2.8%)
Kenya 72 54.7 (2.7%)
Estonia 73 12.3 (2.5%)
Iraq 74 99.8 (2.5%)
Mexico 75 683 (2.4%)
Azerbaijan 76 42.7 (2.3%)
Cyprus 77 9.1 (2.3%)
Namibia 78 11.0 (2.3%)
Angola 79 45.1 (2.2%)
Cameroon 80 32.7 (2.2%)
India 81 3,483 (2.1%)
Congo 82 5.9 (2.0%)
Bolivia 83 26.9 (1.8%)
Zimbabwe 84 44.0 (1.7%)
Chinese Taipei 85 319 (1.7%)
Netherlands 86 241 (1.6%)
Ukraine 87 457 (1.6%)
Cote d'Ivoire 88 40.4 (1.5%)
Ethiopia 89 140 (1.5%)
Pakistan 90 483 (1.5%)
Cambodia 91 23.8 (1.4%)
Nepal 92 50.4 (1.4%)
Lebanon 93 20.4 (1.4%)
Iran 94 815 (1.2%)
Gabon 95 14.4 (1.2%)
Malaysia 96 378 (1.1%)
Israel 97 60.5 (1.0%)
Egypt 98 356 (0.96%)
Thailand 99 647 (0.92%)
South Africa 100 504 (0.88%)
Kazakhstan 101 268 (0.83%)
South Korea 102 953 (0.82%)
Malta 103 7.1 (0.76%)
Jamaica 104 9.3 (0.73%)
Indonesia 105 952 (0.70%)
Togo 106 10.3 (0.68%)
Haiti 107 9.9 (0.61%)
Uzbekistan 108 288 (0.60%)
Tanzania 109 101 (0.55%)
Moldova 110 14.9 (0.54%)
Tunisia 111 59.1 (0.53%)
Senegal 112 14.6 (0.48%)
Hungary 113 96.4 (0.43%)
Nigeria 114 551 (0.37%)
Mongolia 115 28.4 (0.28%)
Cuba 116 35.8 (0.20%)
Jordan 117 20.9 (0.17%)
Algeria 118 213 (0.14%)
Bangladesh 119 207 (0.11%)
Congo 120 139 (0.05%)
Libya 121 53.1 (0.04%)
United Arab Emirates 122 428 (0.03%)
Saudi Arabia 123 381 (0.01%)
Benin 124 14.8 (0.01%)
Belarus 125 193 (0.01%)
Bahrain 126 23.1 (0.00%)
Turkmenistan 127 143 (0.00%)
Yemen 128 29.3 (0.00%)
Botswana 129 11.3 (0.00%)
Brunei Darussalam 130 9.6 (0.00%)
Eritrea 131 2.3 (0.00%)
Gibraltar 132 5.3 (0.00%)
Hong Kong 133 122 (0.00%)
Kuwait 134 77.5 (0.00%)
Netherlands Antilles 135 10.6 (0.00%)
Oman 136 115 (0.00%)
Qatar 137 89.0 (0.00%)
Singapore 138 233 (0.00%)
Trinidad and Tobago 139 27.3 (0.00%)
0
10
20
30
40
50
60
70
Nameplate capacity (GW) of 2050 WWS needed and percent installed at 2014 end
World: 45.05 TW (3.8%)

Table 2 also lists 1) installed capacities beyond those needed to match annually averaged power demand for CSP with storage, 2) solar thermal for current and stored heat, and 3) geothermal for current and stored heat. These additional capacities are estimated using data from the grid integration study of Jacobson et al. (2015b) and are needed to produce peaking power, to account for additional loads due to losses in and out of storage, and to ensure reliability of the grid, as described and quantified in that paper (see also Section 6).

Table 3. Percent of annually-averaged 2050 country-specific all-purpose end-use load (not installed capacity) in a WWS world from Table 1 proposed here to be met by the given electric power generator. All rows add up to 100%.

Country	On-shore wind	Off-shore wind	Wave	Geoth-ermal	Hydro-electric	Tidal	Res PV	Comm/gov PV	Utility PV	CSP
Albania	1.50	0.28	2.00	0.00	35.10	0.45	7.54	9.59	43.54	0.00
Algeria	1.25	0.00	0.92	0.00	0.25	0.02	9.33	10.33	62.90	15.00
Angola	8.00	1.70	3.00	0.00	3.64	0.09	36.92	27.57	8.58	10.50
Argentina	30.00	20.00	2.80	1.07	7.27	0.01	8.04	9.22	11.59	10.00
Armenia	18.50	0.00	0.00	0.64	16.96	0.00	5.09	5.46	33.35	20.00
Australia	30.00	6.20	5.00	0.40	4.93	0.14	4.83	5.98	32.53	10.00
Austria	27.00	0.00	0.00	0.00	22.68	0.00	5.12	5.55	39.45	0.20
Azerbaijan	45.00	0.00	0.00	0.00	4.42	0.00	6.91	8.89	27.78	7.00
Bahrain	1.00	8.00	1.25	0.00	0.00	0.19	3.32	5.41	60.83	20.00
Bangladesh	15.00	0.00	0.65	0.00	0.27	0.09	16.55	6.59	55.85	5.00
Belarus	45.00	0.00	0.00	0.02	0.01	0.00	0.77	1.43	51.77	1.00
Belgium	8.00	18.00	0.08	0.00	1.83	0.03	4.56	4.75	62.75	0.00
Benin	29.20	0.30	0.50	0.00	0.02	0.38	11.96	5.81	41.83	10.00
Bolivia	25.00	0.00	0.00	14.98	3.17	0.00	20.12	8.61	23.12	5.00
Bosnia and Herzegovina	10.50	1.20	0.22	0.00	21.86	0.27	6.85	9.43	44.67	5.00
Botswana	30.00	0.00	0.00	0.00	0.00	0.00	5.53	8.61	40.85	15.00
Brazil	0.85	17.00	0.97	0.00	11.31	0.01	7.40	10.21	42.24	10.00
Brunei Darussalam	5.00	11.50	0.00	0.00	0.00	0.00	7.00	8.78	57.72	10.00
Bulgaria	7.00	0.00	0.00	0.00	12.23	0.08	1.56	4.40	74.72	0.00
Cambodia	30.00	7.90	2.00	0.00	2.68	0.19	26.02	12.15	14.05	5.00
Cameroon	15.00	1.50	1.00	0.00	5.19	0.18	10.03	5.47	46.63	15.00
Canada	37.50	21.00	2.00	1.91	16.24	0.21	1.46	1.69	17.99	0.00
Chile	25.00	10.00	1.00	3.15	6.67	0.05	5.33	6.92	36.89	5.00
China	16.00	12.90	0.20	0.05	4.33	0.02	3.65	4.52	49.34	9.00
Chinese Taipei	2.00	38.00	0.70	27.14	2.08	0.01	1.48	3.11	25.48	0.00
Colombia	25.00	14.10	1.00	0.00	14.43	0.38	9.38	6.26	24.45	5.00
Congo	10.00	12.00	1.90	0.00	4.90	1.01	27.71	21.61	20.88	0.00
Congo, Dem. Republic	10.00	0.00	0.00	0.00	0.11	0.04	6.75	1.73	56.37	25.00
Costa Rica	3.00	1.10	1.00	26.68	21.71	0.31	17.05	17.39	6.76	5.00
Cote d'Ivoire	22.40	7.00	2.50	0.00	3.62	0.15	11.23	7.09	45.91	0.10
Croatia	30.00	0.00	1.00	0.00	11.74	0.13	2.41	4.84	48.87	1.00
Cuba	22.93	15.00	2.00	0.00	0.29	0.12	13.34	8.40	32.92	5.00
Cyprus	20.00	13.00	1.00	0.00	0.00	0.51	13.02	14.06	28.41	10.00
Czech Republic	25.00	0.00	0.00	0.00	4.39	0.00	4.14	6.64	59.84	0.00
Denmark	28.00	57.00	3.00	0.00	0.03	0.08	1.59	1.64	8.66	0.00
Dominican Republic	25.00	5.00	2.00	9.94	4.63	0.20	24.12	20.01	4.11	5.00
Ecuador	35.00	1.00	2.00	0.33	10.20	0.57	25.22	13.89	11.79	0.00
Egypt	20.00	0.25	1.00	0.00	1.36	0.01	11.72	8.07	42.58	15.00
El Salvador	10.00	2.00	3.00	32.07	8.25	0.43	17.79	10.09	11.37	5.00
Eritrea	15.00	5.00	2.00	0.00	0.00	2.19	52.53	17.26	1.02	5.00
Estonia	60.00	20.66	2.00	0.00	0.12	0.37	0.78	1.29	14.77	0.00
Ethiopia	16.00	0.00	0.00	4.08	2.51	0.00	17.74	5.12	36.55	18.00
Finland	32.00	41.00	1.50	0.00	5.57	0.04	0.25	0.56	19.09	0.00
France	30.00	25.00	1.25	0.02	8.17	0.16	10.36	9.71	14.59	0.75

Gabon	15.00	20.00	2.00	0.00	2.82	0.41	5.97	7.33	46.47	0.00
Georgia	18.00	4.00	2.00	0.00	30.01	0.28	5.21	7.30	33.21	0.00
Germany	18.00	17.00	0.35	0.01	2.20	0.00	5.72	5.49	51.23	0.00
Ghana	21.10	4.00	1.00	0.00	8.25	0.13	8.87	6.34	50.07	0.25
Gibraltar	0.03	35.00	0.50	0.00	0.00	1.17	0.37	0.75	62.15	0.04
Greece	30.00	4.00	1.00	2.40	10.05	0.07	14.19	9.14	24.45	4.70
Guatemala	7.00	3.00	1.00	23.68	5.82	0.14	22.54	10.38	16.43	10.00
Haiti	30.00	11.00	1.00	0.00	1.05	0.43	28.58	6.32	11.61	10.00
Honduras	25.00	7.50	4.00	11.17	5.78	0.26	17.22	6.65	14.92	7.50
Hong Kong, China	0.25	35.00	1.20	0.00	0.00	0.04	3.18	3.71	41.62	15.00
Hungary	1.70	0.00	0.00	2.15	0.18	0.00	3.01	4.37	88.59	0.00
Iceland	39.03	6.00	2.00	23.56	29.05	0.36	0.00	0.00	0.00	0.00
India	17.00	3.20	0.38	0.03	2.54	0.02	6.32	8.71	50.30	11.50
Indonesia	6.30	10.00	2.00	3.88	1.15	0.01	8.73	8.66	49.27	10.00
Iran, Islamic Republic	11.00	2.50	0.20	0.00	2.15	0.01	2.49	2.27	61.39	18.00
Iraq	25.00	0.00	0.10	0.00	4.56	0.00	10.95	6.53	41.96	10.90
Ireland	46.00	37.00	1.80	0.00	2.87	0.13	2.36	2.88	6.95	0.00
Israel	10.00	3.00	0.00	0.00	0.02	0.07	5.71	13.65	47.54	20.00
Italy	11.00	0.90	2.00	0.64	7.77	0.01	6.27	6.31	63.11	2.00
Jamaica	10.00	20.00	5.00	0.00	0.42	0.52	16.44	12.59	35.04	0.00
Japan	4.50	6.00	1.00	0.56	10.51	0.23	7.38	11.36	56.46	2.00
Jordan	30.00	0.00	0.00	0.00	0.12	0.20	9.39	9.13	36.17	15.00
Kazakhstan	46.50	6.50	1.00	0.00	1.56	0.02	2.56	4.09	37.78	0.00
Kenya	21.00	7.00	1.00	10.75	2.67	0.08	14.56	7.28	28.66	7.00
Korea, Dem. People's Rep.	25.00	12.50	2.00	0.00	10.49	0.80	1.84	0.57	46.80	0.00
Korea, Republic of	3.50	12.00	0.60	0.00	1.30	0.13	2.10	4.99	74.13	1.25
Kosovo	15.00	0.00	0.00	37.31	10.31	0.00	2.96	2.86	31.56	0.00
Kuwait	5.00	6.80	1.00	0.00	0.00	0.05	1.39	3.18	54.57	28.00
Kyrgyzstan	15.00	0.00	0.00	0.00	26.62	0.00	8.31	6.03	44.03	0.00
Latvia	35.00	14.50	3.90	0.00	12.16	0.19	0.63	1.17	32.45	0.00
Lebanon	10.00	8.00	0.25	0.00	2.70	0.24	4.41	8.62	60.78	5.00
Libya	26.50	3.50	2.00	0.00	0.00	0.08	5.63	7.87	39.42	15.00
Lithuania	15.00	50.00	0.50	0.00	6.49	0.16	1.78	2.36	23.72	0.00
Luxembourg	7.00	0.00	0.00	0.00	18.28	0.00	5.27	4.86	64.59	0.00
Macedonia, Republic of	40.00	0.00	0.00	0.00	8.58	0.00	5.62	7.98	37.82	0.00
Malaysia	14.00	8.90	1.00	0.00	2.52	0.02	4.07	10.71	58.78	0.00
Malta	1.00	10.00	5.00	0.00	0.00	0.79	4.14	7.94	66.13	5.00
Mexico	25.00	7.90	1.00	2.40	3.19	0.01	10.41	14.09	23.00	13.00
Moldova, Republic of	45.00	0.00	0.00	0.00	1.14	0.00	3.91	4.55	45.40	0.00
Mongolia	38.00	0.00	0.00	0.00	0.22	0.00	2.75	3.20	55.83	0.00
Montenegro	10.00	15.00	2.00	0.00	31.95	1.19	3.98	6.55	29.33	0.00
Morocco	22.50	5.00	2.00	0.00	3.66	0.05	8.41	7.49	45.89	5.00
Mozambique	25.00	2.00	2.00	0.00	10.48	2.37	13.56	4.77	34.81	5.00
Myanmar	10.00	12.00	0.20	0.00	7.86	0.27	20.72	9.56	34.38	5.00
Namibia	14.00	3.25	2.00	0.00	4.52	0.45	3.39	4.00	63.39	5.00
Nepal	15.00	0.00	0.00	0.00	3.21	0.00	11.59	3.77	56.43	10.00
Netherlands	5.00	60.00	0.30	0.00	0.03	0.02	1.60	1.62	31.43	0.00
Netherlands Antilles	2.00	12.50	4.00	0.00	0.00	0.52	3.47	3.21	74.29	0.00
New Zealand	30.00	13.25	1.00	13.29	19.43	0.36	2.77	3.72	16.18	0.00
Nicaragua	10.00	2.00	1.00	18.39	22.49	0.55	23.75	10.01	6.81	5.00
Nigeria	20.00	0.00	0.10	0.00	0.77	0.01	9.65	9.94	39.53	20.00
Norway	14.00	10.00	0.55	0.00	72.86	0.42	0.36	0.71	1.10	0.00
Oman	18.00	3.90	1.00	0.00	0.00	0.04	1.52	1.98	58.57	15.00
Pakistan	2.50	2.25	0.30	0.00	2.93	0.01	12.23	6.65	58.12	15.00
Panama	30.00	5.00	4.00	0.00	11.85	0.78	11.31	10.69	26.38	0.00
Paraguay	4.00	0.00	0.00	0.00	67.83	0.00	17.11	8.03	3.03	0.00
Peru	25.00	0.00	1.00	6.79	10.09	0.07	21.70	13.55	19.80	2.00
Philippines	5.00	10.00	5.00	12.29	4.55	0.29	31.52	17.27	14.09	0.00
Poland	43.00	29.00	0.35	0.16	1.96	0.02	4.83	10.00	10.67	0.00

Portugal	35.00	15.00	1.00	0.63	20.40	0.87	7.37	9.62	7.37	2.75
Qatar	3.50	7.90	0.50	0.00	0.00	0.05	1.21	2.83	77.50	6.50
Romania	24.40	22.00	0.25	0.26	10.07	0.04	1.58	5.36	36.04	0.00
Russian Federation	48.80	22.00	2.00	0.08	4.53	0.02	0.73	1.33	20.51	0.00
Saudi Arabia	11.00	0.00	0.50	0.00	0.00	0.01	3.25	4.33	45.92	35.00
Senegal	20.00	5.00	2.00	0.00	0.95	0.34	18.48	9.04	34.19	10.00
Serbia	25.00	0.00	0.00	0.00	10.34	0.00	2.39	4.97	57.31	0.00
Singapore	0.10	0.48	0.17	6.17	0.00	0.02	3.68	3.56	85.82	0.00
Slovak Republic	35.00	0.00	0.00	0.00	12.03	0.00	2.28	3.87	46.81	0.00
Slovenia	30.00	2.80	0.50	2.01	14.41	0.27	2.34	3.46	44.20	0.00
South Africa	20.00	7.00	1.00	0.00	1.13	0.01	1.56	2.56	56.74	10.00
Spain	25.70	10.00	1.00	0.07	11.86	0.30	10.58	9.42	20.10	10.98
Sri Lanka	20.00	22.00	2.00	0.00	5.79	0.09	18.13	12.22	19.77	0.00
Sudan	12.00	7.35	1.00	0.00	8.04	0.09	21.04	13.39	17.09	20.00
Sweden	55.00	19.00	1.00	0.00	22.01	0.07	0.73	0.97	1.23	0.00
Switzerland	15.00	0.00	0.00	0.00	39.64	0.00	4.41	7.91	33.04	0.00
Syrian Arab Republic	35.00	1.50	0.00	0.00	6.45	0.10	11.82	5.79	32.34	7.00
Tajikistan	30.00	0.00	0.00	0.00	44.61	0.00	16.60	8.00	0.80	0.00
Tanzania, United Republic	18.55	7.00	1.00	0.00	1.11	0.49	8.38	3.63	49.84	10.00
Thailand	11.00	5.40	1.00	0.07	1.45	0.01	3.42	4.38	68.27	5.00
Togo	21.50	2.00	0.60	0.00	1.67	0.59	11.74	3.71	53.20	5.00
Trinidad and Tobago	1.00	48.00	1.00	0.00	0.00	0.18	3.67	3.55	41.60	1.00
Tunisia	23.00	4.00	1.00	0.00	0.24	0.08	5.12	5.60	55.96	5.00
Turkey	16.00	0.05	0.50	0.83	14.46	0.02	10.90	10.16	39.08	8.00
Turkmenistan	16.00	0.00	0.00	0.00	0.00	0.00	1.43	2.80	79.76	0.00
Ukraine	25.00	30.00	1.00	0.00	2.50	0.01	1.46	2.05	37.98	0.00
United Arab Emirates	4.00	4.00	0.50	0.00	0.00	0.01	0.79	1.31	79.39	10.00
United Kingdom	20.00	65.00	0.80	0.00	1.73	2.19	1.09	2.96	6.22	0.00
United States of America	30.92	17.50	0.37	0.45	3.92	0.01	8.04	7.36	24.14	7.30
Uruguay	30.00	13.50	2.00	0.00	16.52	0.26	7.56	10.52	19.64	0.00
Uzbekistan	4.00	0.00	0.00	0.00	1.50	0.00	3.48	2.05	88.97	0.00
Venezuela	15.80	20.00	1.00	0.00	12.98	0.02	6.92	6.00	27.03	10.25
Vietnam	0.01	30.00	1.90	0.00	7.78	0.01	8.40	4.91	33.04	13.95
Yemen	4.00	5.00	2.00	1.20	0.00	0.16	23.13	7.03	44.47	13.00
Zambia	20.00	0.00	0.00	0.78	8.88	0.00	12.98	7.73	31.62	18.00
Zimbabwe	21.50	0.00	0.00	0.00	2.95	0.00	6.42	6.09	39.04	24.00
World average	**19.37**	**12.90**	**0.72**	**0.74**	**4.84**	**0.07**	**5.55**	**5.97**	**42.17**	**7.67**

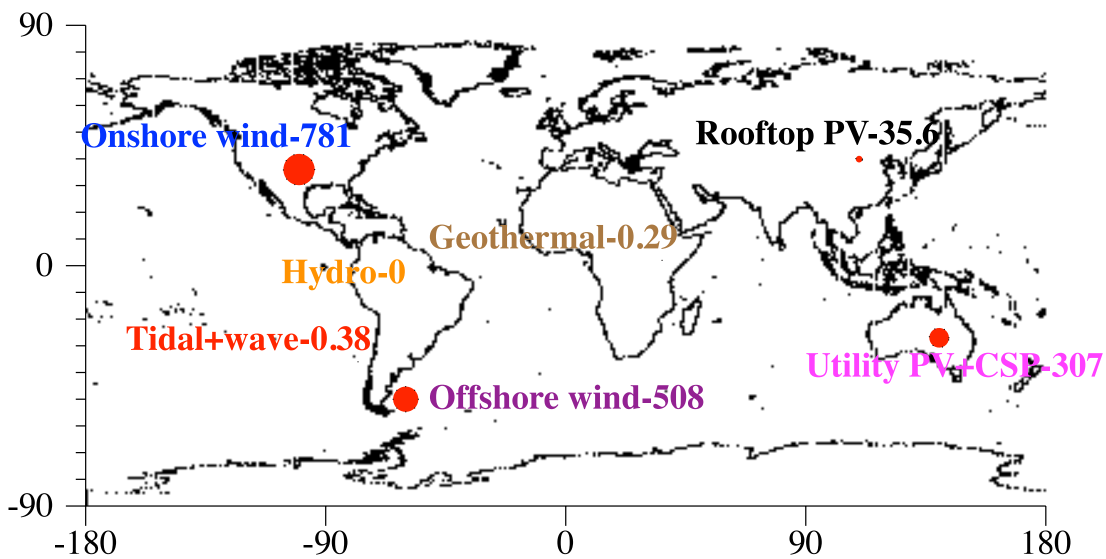
Figure 2 shows the additional footprint and spacing areas required from Table 2 to replace the 139-country all-purpose energy infrastructure with WWS by 2050. Footprint area is the physical area on the top surface of the ground or water needed for each energy device. Spacing area is the area between some devices, such as wind, tidal, and wave turbines, needed to minimize interference of the wake of one turbine with downwind turbines.

Only onshore wind, geothermal, additional hydropower (which none is proposed here), utility PV plants, and CSP plants require new footprint on land. Rooftop PV does not take up new land. Table 2 indicates that the total new land footprint required for the plans, averaged over the 139 countries is ~0.29% of the land area of the countries, mostly for utility PV plants. This does not account for the decrease in footprint from eliminating the current energy infrastructure, which includes the footprint for mining, transporting, and refining fossil fuels and uranium and for growing, transporting, and refining biofuels and bioenergy.

The only spacing over land needed for the WWS system is between onshore wind turbines and requires ~0.65% of the 139-country land area. The footprint associated with this spacing area is small and can also be used for multiple purposes, such as agricultural land, grazing land, and open space. Landowners can thus derive income from both wind turbines on their land and farming around the turbines.

For several reasons, we have not estimated the footprint or spacing area of additional transmission lines. Transmission systems have virtually no footprint on the ground because transmission towers are four metal supports connected to small foundations, allowing grass to grow under the towers. Further, the rights-of-way under transmission lines typically can accommodate many uses; more than can the rights-of-way under gas and oil pipelines and other conventional infrastructure that new transmission lines will replace. Finally, in our roadmaps, as much additional transmission capacity as possible will be placed along existing pathways but with enhanced lines.

Figure 2. Footprint plus spacing areas required from Table 2, beyond existing 2014 resources, to repower the 139 countries for all purposes in 2050. The dots do not indicate the actual location of energy farms, just their relative spacing areas. After the name of each resource the thousands of square kilometers of footprint plus spacing. For hydropower, the new footprint plus spacing area is zero since no new installations are proposed. For tidal + wave and geothermal, the new spacing areas are so small they are difficult to distinguish on the map. For rooftop PV, the circle represents the new rooftop area needed.



5. Resource Availability

This section evaluates whether the 139 countries have sufficient wind, solar, geothermal, and hydropower resources to supply each country's all-purpose power in 2050.

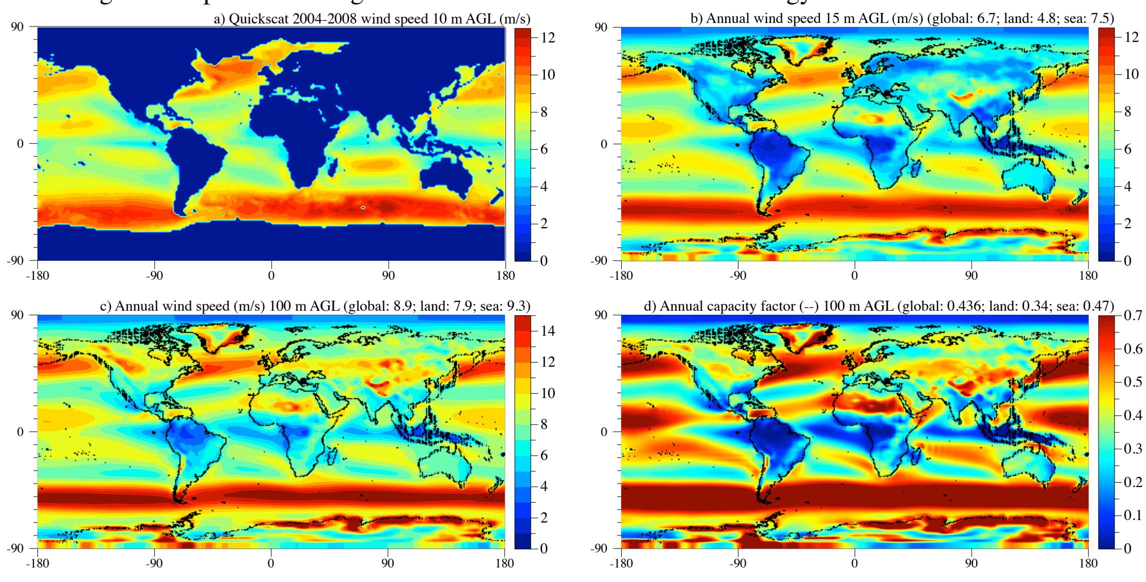
5.1. Wind

Figure 3 shows three-dimensional computer model estimates, derived for this study, of the world annually averaged wind speed and capacity factor at the 100-m hub height above the topographical surface of modern wind turbines. The figure also compares near-surface modeled wind speeds with QuikSCAT data over the oceans, suggesting model predictions and data are similar at that height giving confidence in the 100-m values.

Locations of strong onshore wind resources include the Great Plains of the U.S. and Canada, the Sahara desert, the Gobi desert, much of Australia, the south of Argentina, South Africa, and northern Europe among other locations. Strong offshore wind resources occur off the east and west coasts of North America, over the Great Lakes, the North Sea, the west coast of Europe and the east coast of Asia, offshore of Peru and Argentina, Australia, South Africa, India, Saudi Arabia, and west Africa.

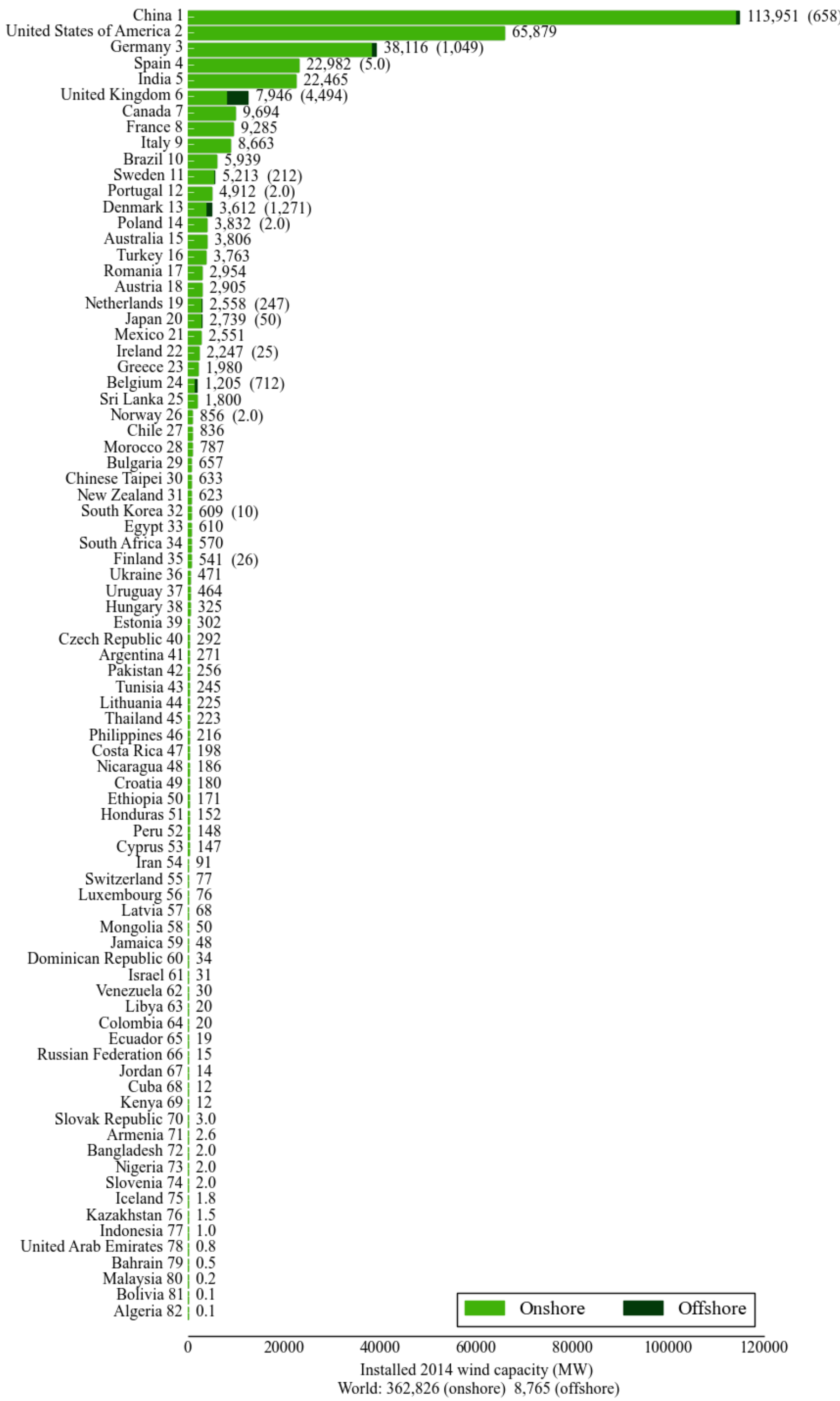
Our estimates of the nameplate capacity of onshore and offshore wind to be installed in each country (Tables 2 and 3) are limited by the country's power demand and technical potential available for onshore (NREL, 2012a) and offshore (Arent et al., 2012) turbines. Only 3.5% of the onshore technical potential and 27.2% of the near-shore offshore technical potential are proposed for use in 2050. Table 2 indicates that the 2050 WWS roadmaps require ~0.65% of the 139-country onshore land area and 0.42% of the 139-country onshore-equivalent land area sited offshore for wind-turbine spacing to power 32.2% of all-purpose annually-averaged 139-country power in 2015.

Figure 3. (a) QuikSCAT 10-m above ground level (AGL) wind speed at 1.5° x 1.5° resolution (JPL, 2012), (b) GATOR-GCMOM (Jacobson, 2010) 4-year-average modeled annual 15-m AGL wind speed at 2.5° W-E x 2.0° S-N resolution, (c) Same as (b) but at 100 m AGL, (d) Same as (c) but for capacity factor assuming a Senvion (RePower) 5 MW turbine with 126-m rotor diameter. In all cases, wind speeds are determined before accounting for competition among wind turbines for the same kinetic energy.



As of the end of 2014, 3.7% of the proposed 2050 onshore plus offshore wind power nameplate capacity of 10.0 TW among the 139 countries has been installed. Figure 4 indicates that China, the United States, and Germany have installed the greatest capacity of onshore wind, whereas the United Kingdom, Denmark, and Germany have installed the most offshore wind.

Figure 4. Installed onshore and offshore wind power by country as of the end of 2014. Capacity is determined first from GWEC (2014) year-end values for 2014, followed by IEA (2014b) capacity estimates for 2014, then IEA (2015) capacity estimates for 2011.



5.2. Solar

Figure 5 shows annually averaged modeled solar irradiance worldwide accounting for sun angles, day/night, and clouds. The best solar resources are broadly between 40 ºN and 40 ºS. The new land area in 2050 required for non-rooftop solar under the plan here is equivalent to ~0.28% of the 139-country land area (Figure 5).

Figure 5. Modeled annually averaged downward direct plus diffuse solar irradiance at the ground ($kWh/m^2/day$) worldwide. The model used is GATOR-GCMOM (Jacobson, 2010), which simulates clouds, aerosols gases, weather, radiation fields, and variations in surface albedo over time. The model is run with horizontal resolution of 2.5º W-E x 2.0º S-N.

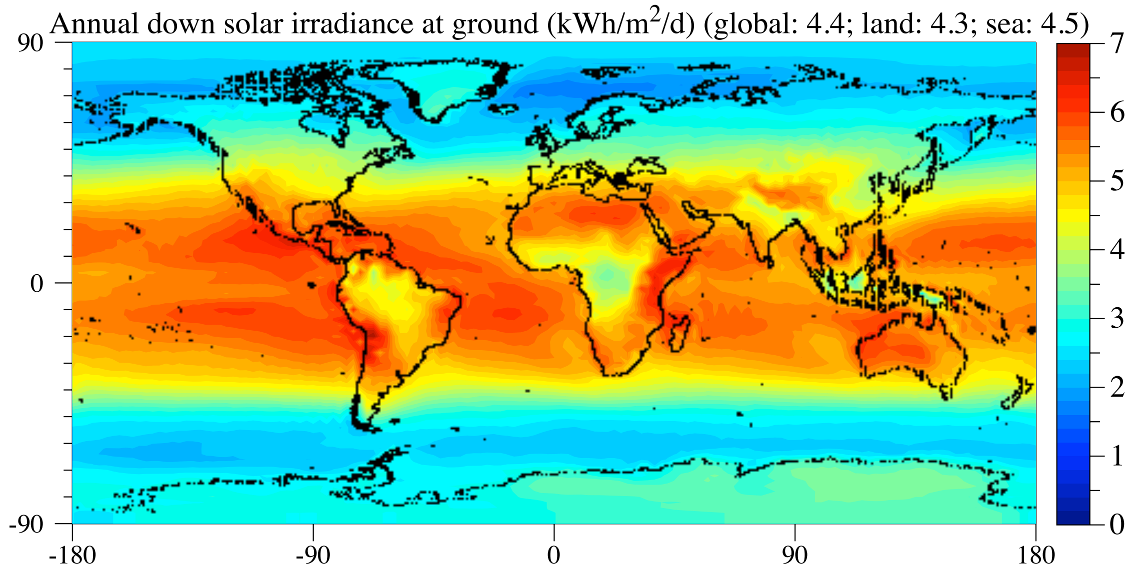


Table 4 provides estimates of each country's maximum rooftop PV nameplate capacity. The proposed capacity for each country, summed in Table 2, is limited by the values in Table 4. Rooftops considered include those on residential, commercial, and governmental buildings, and garages, carports, parking lots, and parking structures associated with these buildings. Commercial and governmental buildings include all non-residential buildings except manufacturing, industrial, and military buildings. Commercial buildings include schools.

The total residential rooftop area suitable for PV in each country in 2050 is calculated first by extrapolating the fraction of 2050 population living in urban versus rural areas linearly but with upper limits from 2005-2014 urban fraction data (World Bank, 2015c). Projected 2050 population in each country is then divided between rural and urban population. Population in each case is then multiplied by floor area per capita by country (assumed the same for rural and urban homes) from Entranze Data Tool (2015) for European countries, IEA (2005) for a few additional countries, and IEA (2014a) for remaining regions of the world. The result is finally multiplied by the utilization factor (UF), which is the ratio of the usable rooftop area to ground floor area. For rural areas in each country, UF=0.2. Eiffert et al. (2003) estimate UF=0.4 for rooftops and 0.15 for facades, but for single-family rural residential homes, we assume shading reduces the UF to 0.2. For urban areas, we assume UF=0.4 but divide the urban area population by the number of floors in each urban complex to account for the fact that urban buildings house more people per unit ground floor area. The number of floors is estimated by country in Europe from Entranze Data Tool (2015) as the number of dwellings per multi-family building divided by an estimated four dwellings on the bottom floor of a building. This gives the average number of floors in an urban area ranging from 2 to 5 for these countries. We assume three floors per urban dwelling in other countries. Potential solar PV installed capacity is then calculated as the installed capacity of a Sunpower E20 435 W panel multiplied by the suitable rooftop area and divided by panel area.

The total commercial rooftop area suitable for PV for European countries in 2050 is calculated as the product of the estimated 2050 country population, the average commercial ground floor area per capita (Entranze Data Tool, 2015), and a UF=0.4 (Eiffert et al., 2003). Scaling the European value to the GDP/capita of countries to that of European countries gives the average commercial ground floor area per capita in other countries. Potential solar PV installed capacity is then the installed capacity of a Sunpower E20 435 W panel multiplied by suitable rooftop area and divided by panel area.

The potential rooftop or canopy area over parking spaces in each country is computed by multiplying the number of passenger cars per person (World Bank, 2014) by the average parking space per car (30 m^2, Dulac, 2013) in the country. Given that 1) some of these parking spaces will be in residential garages that have already been included in the residential rooftop PV calculation, and 2) some parking spaces will not necessarily have a roof (e.g. basement parking spaces), a utilization factor of 0.5 is applied to the estimate for parking area suitable for PV. With these assumptions, the PV capacity on parking-space rooftops is ~15% of the maximum capacity on residential rooftops and ~9% of the maximum capacity on residential-plus-commercial rooftops.

Based on the foregoing analysis, 2050 residential rooftop areas (including garages and carports) are estimated to support up to 6.3 $TW_{dc\text{-}peak}$ of installed power among the 139 countries. The plans here propose to install 39.3% of this potential. In 2050, commercial/government rooftop areas (including parking lots and parking structures) are estimated to support 6.5 $TW_{dc\text{-}peak}$ of installed power. The country plans here propose to cover 55.4% of installable power, with low-latitude, high GDP-per-capita countries expected to adopt solar at a greater pace than high-latitude or low GDP-per-capita countries.

Table 4. Rooftop areas suitable for PV panels, potential capacity of suitable rooftop areas, and proposed installed capacity for both residential and commercial/government buildings, by country. See Delucchi et al. (2015) for calculations.

	Residential rooftop PV				Commercial/government rooftop PV			
Country	Rooftop area suitable for PVs in 2012 (km^2)	Potential capacity of suitable area in 2050 ($MW_{dc\text{-}peak}$)	Proposed installed capacity in 2050 ($MW_{dc\text{-}peak}$)	Percent of potential capacity installed	Rooftop area suitable for PVs in 2012 (km^2)	Potential capacity of suitable area in 2050 ($MW_{dc\text{-}peak}$)	Proposed installed capacity in 2050 ($MW_{dc\text{-}peak}$)	Percent of potential capacity installed
Albania	12.1	2,435	1,162	48	7.6	3,099	1,479	48
Algeria	126.6	25,387	22,848	90	92.2	28,120	25,308	90
Angola	104.8	21,009	16,822	80	71.8	15,691	12,564	80
Argentina	216.4	43,396	30,806	71	136.6	49,738	35,308	71
Armenia	14.3	2,863	1,099	38	7.1	3,073	1,180	38

Australia	178.9	35,869	21,582	60	91.0	44,424	26,729	60
Austria	54.0	10,826	9,744	90	24.7	11,747	10,573	90
Azerbaijan	53.4	10,700	4,644	43	36.2	13,776	5,980	43
Bahrain	5.2	1,038	934	90	4.6	1,694	1,525	90
Bangladesh	799.8	160,388	39,670	25	305.3	63,873	15,798	25
Belarus	32.3	6,470	2,119	33	25.3	12,053	3,948	33
Belgium	73.1	14,655	13,144	90	31.7	15,282	13,706	90
Benin	53.7	10,760	2,112	20	18.4	5,229	1,026	20
Bolivia	69.2	13,870	6,607	48	24.0	5,936	2,828	48
Bosnia and Herzegovina	20.2	4,046	1,830	45	10.3	5,568	2,519	45
Botswana	6.7	1,350	809	60	6.3	2,100	1,258	60
Brazil	1,063.7	213,295	135,738	64	647.2	294,162	187,201	64
Brunei Darussalam	4.0	803	723	90	2.6	1,008	907	90
Bulgaria	12.7	2,544	1,303	51	14.8	7,164	3,670	51
Cambodia	81.7	16,389	6,997	43	27.8	7,652	3,267	43
Cameroon	78.5	15,748	3,769	24	36.4	8,593	2,057	24
Canada	266.7	53,481	21,480	40	128.0	61,963	24,887	40
Chile	78.6	15,767	11,739	74	56.1	20,466	15,237	74
China	5,606.0	1,124,149	622,325	55	4029.9	1,395,466	772,526	55
Chinese Taipei	57.6	11,559	7,794	67	89.8	24,197	16,315	67
Colombia	240.1	48,137	17,524	36	114.0	32,152	11,705	36
Congo	21.0	4,217	1,635	39	14.1	3,289	1,275	39
Congo, Dem. Republic	347.7	69,727	10,920	16	76.9	17,858	2,797	16
Costa Rica	25.3	5,082	3,073	60	12.9	5,185	3,135	60
Cote d'Ivoire	81.6	16,360	4,670	29	40.4	10,331	2,949	29
Croatia	15.2	3,057	1,327	43	13.2	6,143	2,666	43
Cuba	40.3	8,072	5,901	73	22.6	5,083	3,716	73
Cyprus	10.8	2,162	1,470	68	5.4	2,335	1,588	68
Czech Republic	39.0	7,820	7,038	90	24.2	12,557	11,301	90
Denmark	40.0	8,019	2,026	25	18.2	8,293	2,095	25
Dominican Republic	56.5	11,328	6,618	58	27.7	9,397	5,490	58
Ecuador	96.8	19,411	11,593	60	40.0	10,690	6,385	60
Egypt	472.4	94,722	52,748	56	254.0	65,258	36,340	56
El Salvador	26.6	5,333	2,385	45	10.2	3,023	1,352	45
Eritrea	30.2	6,047	1,419	23	8.6	1,987	466	23
Estonia	3.8	761	204	27	2.3	1,249	334	27
Ethiopia	745.9	149,576	33,013	22	208.4	43,196	9,534	22
Finland	16.3	3,275	654	20	15.2	7,392	1,476	20
France	566.5	113,604	102,243	90	216.9	106,447	95,802	90
Gabon	6.5	1,308	826	63	7.6	1,607	1,015	63
Georgia	18.4	3,686	1,414	38	9.0	5,166	1,982	38
Germany	579.2	116,150	104,535	90	234.5	111,578	100,420	90
Ghana	89.4	17,929	4,678	26	48.7	12,816	3,344	26
Gibraltar	0.1	22	20	90	0.1	46	41	90
Greece	111.7	22,390	12,513	56	26.8	14,431	8,065	56
Guatemala	107.3	21,507	9,157	43	36.3	9,903	4,216	43
Haiti	57.4	11,514	3,480	30	10.7	2,548	770	30
Honduras	57.8	11,593	3,963	34	16.4	4,480	1,532	34
Hong Kong, China	24.7	4,951	4,456	90	23.3	5,777	5,199	90
Hungary	36.8	7,374	2,989	41	22.4	10,710	4,341	41
Iceland	1.4	284	0	0	1.1	543	0	0
India	2,818.9	565,256	280,689	50	3270.3	779,505	387,079	50
Indonesia	929.1	186,312	95,952	52	663.0	184,926	95,238	52
Iran, Islamic Republic	283.6	56,861	26,057	46	164.0	51,841	23,757	46
Iraq	171.5	34,397	14,321	42	87.4	20,516	8,542	42
Ireland	40.1	8,032	1,854	23	21.3	9,828	2,268	23
Israel	29.7	5,955	4,327	73	31.6	14,228	10,338	73
Italy	457.1	91,652	47,890	52	183.2	92,146	48,148	52
Jamaica	17.0	3,402	1,749	51	6.2	2,607	1,340	51

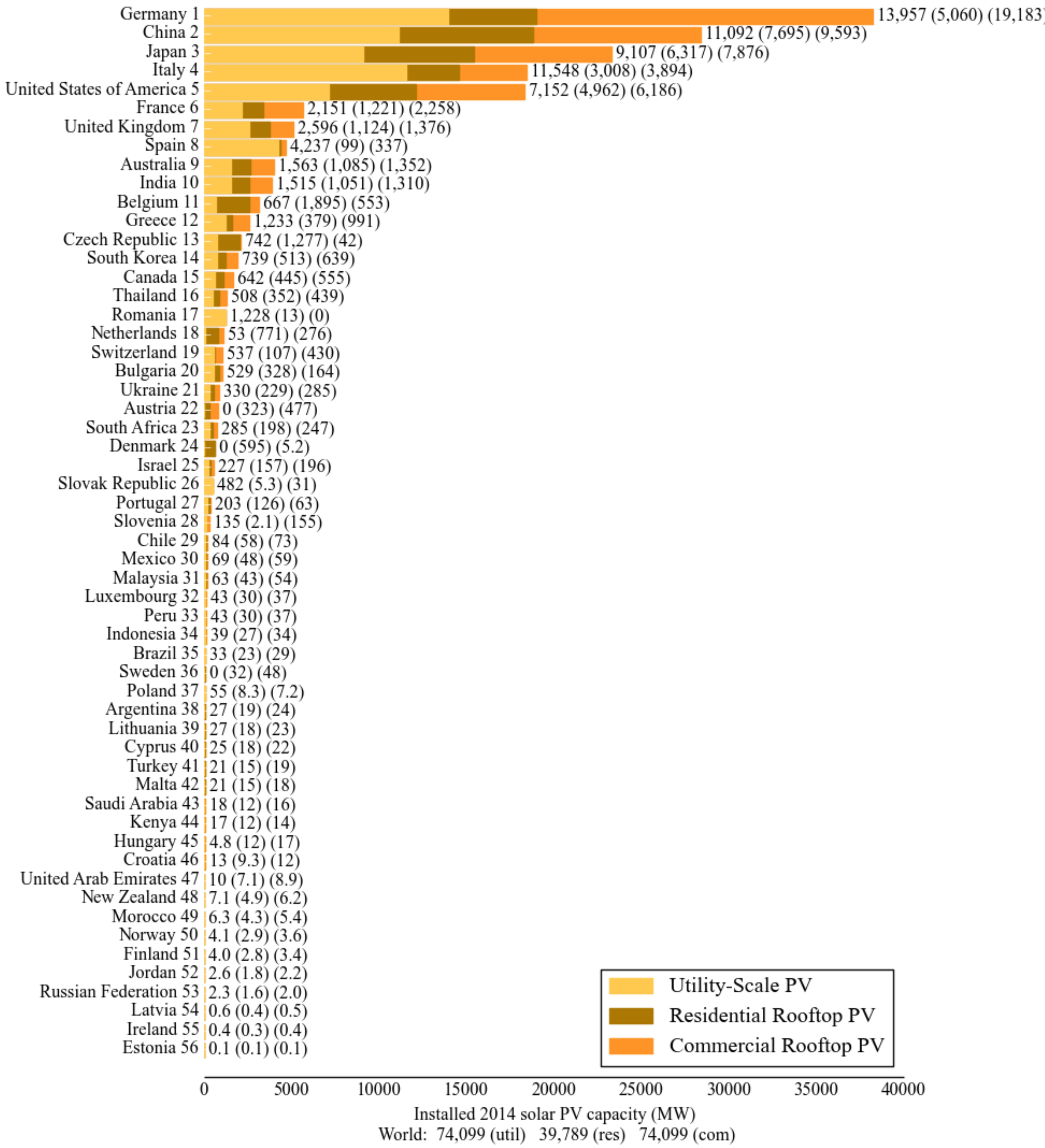
Japan	491.7	98,606	88,745	90	291.8	151,825	136,643	90
Jordan	31.1	6,234	2,641	42	16.1	6,061	2,568	42
Kazakhstan	112.5	22,558	10,548	47	79.7	36,050	16,857	47
Kenya	184.6	37,014	10,740	29	73.5	18,512	5,372	29
Korea, Dem. People's Rep.	84.8	17,011	3,188	19	22.3	5,286	990	19
Korea, Republic of	123.3	24,728	22,255	90	128.8	58,749	52,874	90
Kosovo	5.3	1,072	335	31	2.6	1,033	323	31
Kuwait	10.4	2,077	1,449	70	11.9	4,738	3,304	70
Kyrgyzstan	43.4	8,710	2,728	31	13.8	6,322	1,980	31
Latvia	6.8	1,356	338	25	5.5	2,493	621	25
Lebanon	11.5	2,311	1,065	46	7.0	4,516	2,082	46
Libya	31.3	6,278	3,999	64	23.6	8,772	5,587	64
Lithuania	17.2	3,455	1,033	30	10.3	4,587	1,371	30
Luxembourg	6.7	1,346	1,207	90	2.9	1,241	1,113	90
Macedonia, Republic of	9.8	1,961	1,005	51	5.8	2,783	1,426	51
Malaysia	120.9	24,240	15,386	63	124.9	63,788	40,489	63
Malta	1.7	347	313	90	1.5	666	599	90
Mexico	622.0	124,735	90,390	72	382.7	168,888	122,385	72
Moldova, Republic of	11.6	2,332	811	35	4.5	2,709	942	35
Mongolia	12.4	2,489	1,043	42	9.5	2,901	1,215	42
Montenegro	2.7	532	241	45	1.8	876	397	45
Morocco	124.4	24,947	9,955	40	66.0	22,203	8,860	40
Mozambique	153.8	30,834	6,668	22	38.6	10,855	2,347	22
Myanmar	238.6	47,836	18,236	38	101.4	22,073	8,415	38
Namibia	4.7	941	443	47	3.8	1,111	523	47
Nepal	165.3	33,157	7,343	22	49.4	10,790	2,390	22
Netherlands	137.7	27,613	7,498	27	59.5	28,092	7,628	27
Netherlands Antilles	2.1	417	375	90	1.1	386	347	90
New Zealand	30.3	6,084	2,388	39	17.3	8,154	3,201	39
Nicaragua	33.1	6,628	2,569	39	10.8	2,792	1,082	39
Nigeria	891.2	178,709	66,426	37	654.5	184,011	68,397	37
Norway	20.8	4,163	736	18	18.4	8,175	1,445	18
Oman	14.9	2,995	2,206	74	13.1	3,915	2,883	74
Pakistan	960.6	192,621	71,027	37	433.2	104,762	38,630	37
Panama	21.7	4,351	3,118	72	11.8	4,114	2,948	72
Paraguay	41.1	8,238	4,031	49	15.1	3,865	1,891	49
Peru	154.1	30,896	17,822	58	71.6	19,302	11,134	58
Philippines	606.4	121,603	60,273	50	300.7	66,623	33,022	50
Poland	110.7	22,208	19,987	90	85.0	45,989	41,390	90
Portugal	55.0	11,037	5,711	52	27.1	14,407	7,454	52
Qatar	6.8	1,368	1,232	90	9.6	3,202	2,882	90
Romania	41.8	8,374	3,402	41	60.4	28,400	11,536	41
Russian Federation	408.3	81,868	28,542	35	321.9	149,203	52,018	35
Saudi Arabia	112.3	22,517	17,271	77	106.0	29,998	23,008	77
Senegal	67.5	13,543	3,398	25	25.1	6,629	1,663	25
Serbia	21.0	4,208	1,906	45	17.2	8,746	3,963	45
Singapore	51.7	10,359	9,323	90	36.4	10,039	9,035	90
Slovak Republic	21.2	4,243	1,571	37	13.6	7,182	2,660	37
Slovenia	7.9	1,583	650	41	4.5	2,341	962	41
South Africa	107.0	21,451	10,198	48	99.6	35,152	16,712	48
Spain	439.3	88,091	46,934	53	155.2	78,479	41,813	53
Sri Lanka	94.6	18,979	11,368	60	52.4	12,787	7,660	60
Sudan	255.9	51,306	15,139	30	117.2	32,655	9,635	30
Sweden	52.9	10,601	2,371	22	29.9	14,196	3,176	22
Switzerland	32.8	6,576	5,919	90	25.9	11,785	10,606	90
Syrian Arab Republic	102.7	20,603	6,937	34	39.2	10,091	3,398	34
Tajikistan	66.1	13,258	3,928	30	18.6	6,388	1,893	30
Tanzania, United Republic	163.8	32,853	9,821	30	65.3	14,219	4,251	30
Thailand	199.6	40,015	24,410	61	165.1	51,258	31,269	61

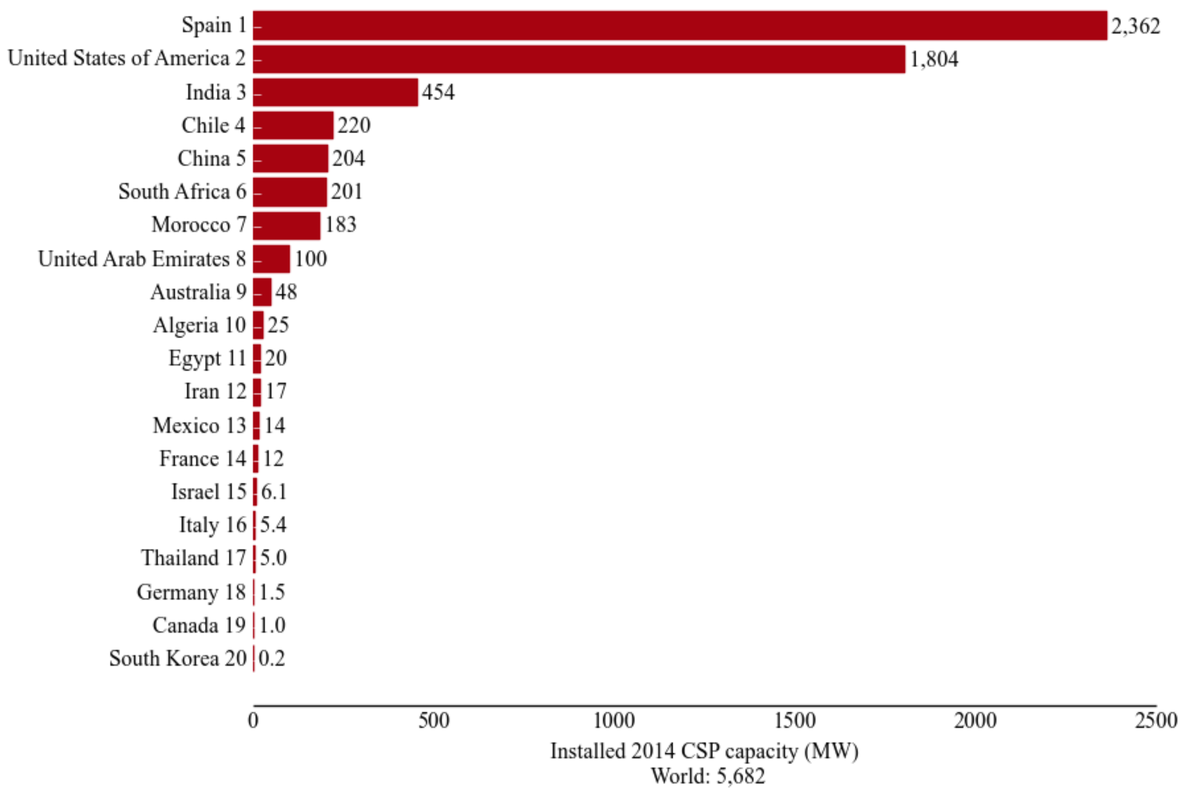
Togo	40.4	8,097	1,386	17	12.2	2,558	438	17
Trinidad and Tobago	6.1	1,220	1,098	90	2.9	1,181	1,063	90
Tunisia	36.9	7,401	3,591	49	23.4	8,105	3,933	49
Turkey	429.1	86,050	45,069	52	243.7	80,238	42,025	52
Turkmenistan	21.1	4,240	2,347	55	20.4	8,278	4,583	55
Ukraine	150.3	30,140	11,089	37	83.8	42,433	15,611	37
United Arab Emirates	21.6	4,340	3,906	90	23.1	7,199	6,479	90
United Kingdom	199.4	39,990	10,859	27	222.0	108,727	29,523	27
United States of America	3,723.1	746,577	494,885	66	1507.1	683,515	453,083	66
Uruguay	14.0	2,803	1,690	60	8.5	3,903	2,353	60
Uzbekistan	124.5	24,969	10,749	43	73.4	14,720	6,337	43
Venezuela	168.7	33,834	19,985	59	91.3	29,302	17,308	59
Vietnam	362.4	72,664	34,414	47	177.0	42,517	20,136	47
Yemen	150.0	30,073	8,078	27	38.8	9,136	2,454	27
Zambia	93.7	18,789	6,353	34	45.4	11,199	3,787	34
Zimbabwe	69.0	13,846	3,735	27	20.5	13,132	3,542	27
World total or average	**31,356**	**6,287,586**	**3,304,963**	**39.30**	**19,070**	**6,482,448**	**3,589,760**	**55.38**

Utility-scale PV potential is determined with the NREL Global Solar Opportunity Tool (NREL, 2012b), which gives the utility PV potential (in GW of rated capacity) by country for different resource thresholds. We define the utility-scale PV potential as the potential calculated from the tool in locations exceeding 4 kWh/m^2/day.

As of the end of 2014, 0.55% of the proposed 2050 PV (residential rooftop, commercial/government rooftop, and utility scale) capacity and 0.37% of the CSP capacity among the 139 countries from Table 2 has been installed. Figure 6 indicates that Germany, China, Japan, and Italy have installed the most PV. Spain, the United States, and India have installed the most CSP.

Figure 6. (a) Installed residential, commercial/government, plus utility PV by country and (b) installed CSP by country as of the end of 2014. Total PV is determined first from IEA-PVPS (2015) and IEA (2014b); the ratios of residential : commercial/government : utility PV for 20 European countries and global averages were obtained from EPIA (2014). CSP by country includes operational plants and plants under construction that broke ground before 2015 (CSP World, 2015; NREL, 2015).


Germany 1 13,957 (5,060) (19,183)
China 2 11,092 (7,695) (9,593)
Japan 3 9,107 (6,317) (7,876)
Italy 4 11,548 (3,008) (3,894)
United States of America 5 7,152 (4,962) (6,186)
France 6 2,151 (1,221) (2,258)
United Kingdom 7 2,596 (1,124) (1,376)
Spain 8 4,237 (99) (337)
Australia 9 1,563 (1,085) (1,352)
India 10 1,515 (1,051) (1,310)
Belgium 11 667 (1,895) (553)
Greece 12 1,233 (379) (991)
Czech Republic 13 742 (1,277) (42)
South Korea 14 739 (513) (639)
Canada 15 642 (445) (555)
Thailand 16 508 (352) (439)
Romania 17 1,228 (13) (0)
Netherlands 18 53 (771) (276)
Switzerland 19 537 (107) (430)
Bulgaria 20 529 (328) (164)
Ukraine 21 330 (229) (285)
Austria 22 0 (323) (477)
South Africa 23 285 (198) (247)
Denmark 24 0 (595) (5.2)
Israel 25 227 (157) (196)
Slovak Republic 26 482 (5.3) (31)
Portugal 27 203 (126) (63)
Slovenia 28 135 (2.1) (155)
Chile 29 84 (58) (73)
Mexico 30 69 (48) (59)
Malaysia 31 63 (43) (54)
Luxembourg 32 43 (30) (37)
Peru 33 43 (30) (37)
Indonesia 34 39 (27) (34)
Brazil 35 33 (23) (29)
Sweden 36 0 (32) (48)
Poland 37 55 (8.3) (7.2)
Argentina 38 27 (19) (24)
Lithuania 39 27 (18) (23)
Cyprus 40 25 (18) (22)
Turkey 41 21 (15) (19)
Malta 42 21 (15) (18)
Saudi Arabia 43 18 (12) (16)
Kenya 44 17 (12) (14)
Hungary 45 4.8 (12) (17)
Croatia 46 13 (9.3) (12)
United Arab Emirates 47 10 (7.1) (8.9)
New Zealand 48 7.1 (4.9) (6.2)
Morocco 49 6.3 (4.3) (5.4)
Norway 50 4.1 (2.9) (3.6)
Finland 51 4.0 (2.8) (3.4)
Jordan 52 2.6 (1.8) (2.2)
Russian Federation 53 2.3 (1.6) (2.0)
Latvia 54 0.6 (0.4) (0.5)
Ireland 55 0.4 (0.3) (0.4)
Estonia 56 0.1 (0.1) (0.1)
Utility-Scale PV
Residential Rooftop PV
Commercial Rooftop PV
0
5000
10000
15000
20000
25000
30000
35000
40000
Installed 2014 solar PV capacity (MW)
World: 74,099 (util) 39,789 (res) 74,099 (com)

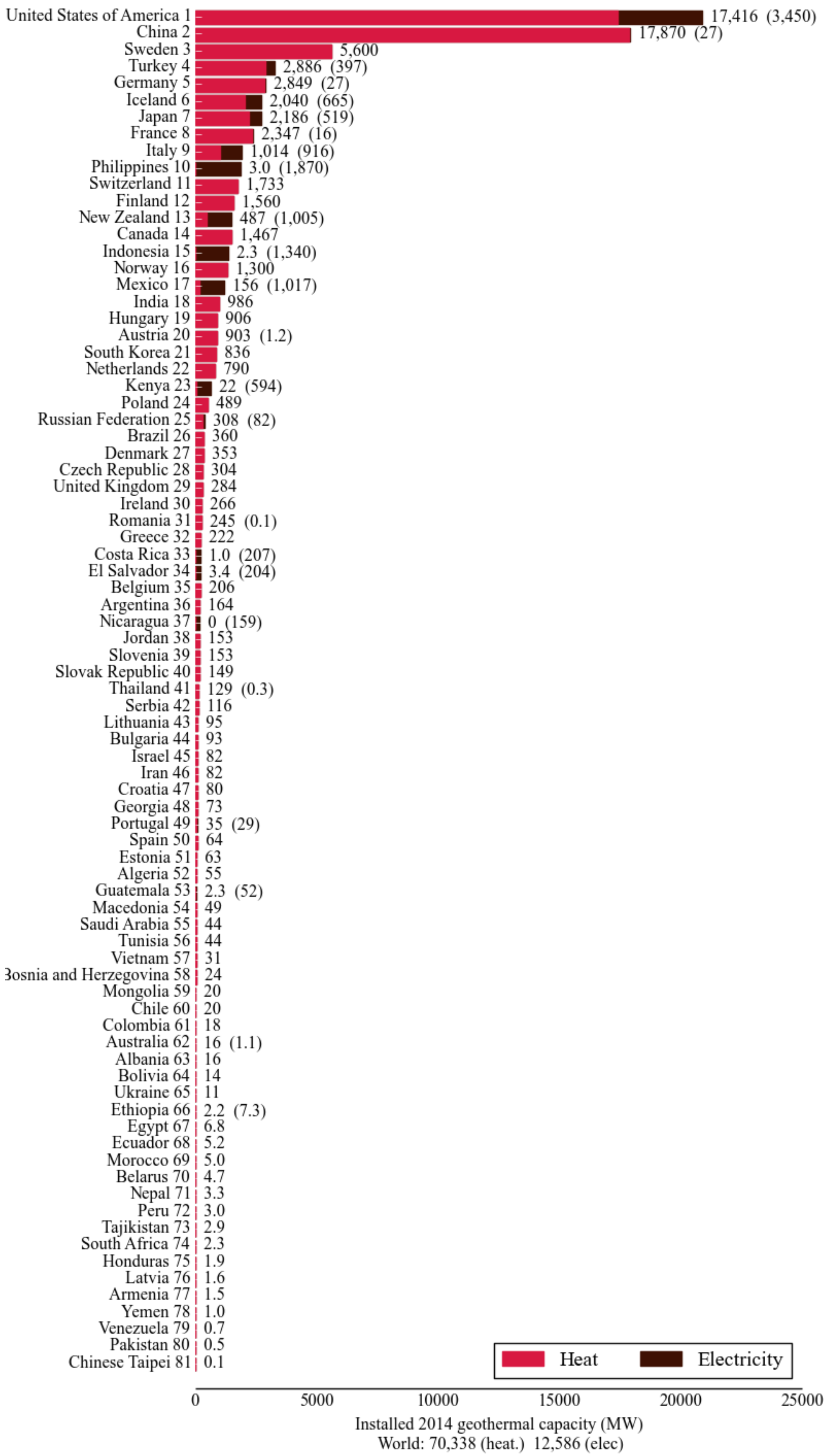


5.3. Geothermal

Geothermal heat from volcanos, geysers, hot springs, conduction from the interior of the Earth, and solar radiation absorbed by the ground can be used to generate electricity or produce heat, depending on the temperature of the resource. All countries can extract heat from the ground for direct heating or use in heat pumps.

As of the end of 2014, 12.586 GW of geothermal has been installed for electric power and 70.338 GW has been installed for heat worldwide. The United States, Philippines, and Indonesia lead electric power installations, whereas China, the United States, and Sweden lead heat installations (Figure 7). The installed geothermal for electricity represents 13.0% of the nameplate capacity of geothermal needed for electric power generation under the plans proposed here (Table 2). The installed geothermal for heat represents 100% of the nameplate capacity of geothermal needed for heat storage (Table 2).

Figure 7. Installed geothermal power for (a) electricity and (b) heat by country, 2014 (Lund and Boyd, 2015; Bertani, 2015; REN21, 2015).


United States of America 1
17,416 (3,450)
China 2
17,870 (27)
Sweden 3
5,600
Turkey 4
2,886 (397)
Germany 5
2,849 (27)
Iceland 6
2,040 (665)
Japan 7
2,186 (519)
France 8
2,347 (16)
Italy 9
1,014 (916)
Philippines 10
3.0 (1,870)
Switzerland 11
1,733
Finland 12
1,560
New Zealand 13
487 (1,005)
Canada 14
1,467
Indonesia 15
2.3 (1,340)
Norway 16
1,300
Mexico 17
156 (1,017)
India 18
986
Hungary 19
906
Austria 20
903 (1.2)
South Korea 21
836
Netherlands 22
790
Kenya 23
22 (594)
Poland 24
489
Russian Federation 25
308 (82)
Brazil 26
360
Denmark 27
353
Czech Republic 28
304
United Kingdom 29
284
Ireland 30
266
Romania 31
245 (0.1)
Greece 32
222
Costa Rica 33
1.0 (207)
El Salvador 34
3.4 (204)
Belgium 35
206
Argentina 36
164
Nicaragua 37
0 (159)
Jordan 38
153
Slovenia 39
153
Slovak Republic 40
149
Thailand 41
129 (0.3)
Serbia 42
116
Lithuania 43
95
Bulgaria 44
93
Israel 45
82
Iran 46
82
Croatia 47
80
Georgia 48
73
Portugal 49
35 (29)
Spain 50
64
Estonia 51
63
Algeria 52
55
Guatemala 53
2.3 (52)
Macedonia 54
49
Saudi Arabia 55
44
Tunisia 56
44
Vietnam 57
31
Bosnia and Herzegovina 58
24
Mongolia 59
20
Chile 60
20
Colombia 61
18
Australia 62
16 (1.1)
Albania 63
16
Bolivia 64
14
Ukraine 65
11
Ethiopia 66
2.2 (7.3)
Egypt 67
6.8
Ecuador 68
5.2
Morocco 69
5.0
Belarus 70
4.7
Nepal 71
3.3
Peru 72
3.0
Tajikistan 73
2.9
South Africa 74
2.3
Honduras 75
1.9
Latvia 76
1.6
Armenia 77
1.5
Yemen 78
1.0
Venezuela 79
0.7
Pakistan 80
0.5
Chinese Taipei 81
0.1
Heat
Electricity
0
5000
10000
15000
20000
25000
Installed 2014 geothermal capacity (MW)
World: 70,338 (heat.) 12,586 (elec)

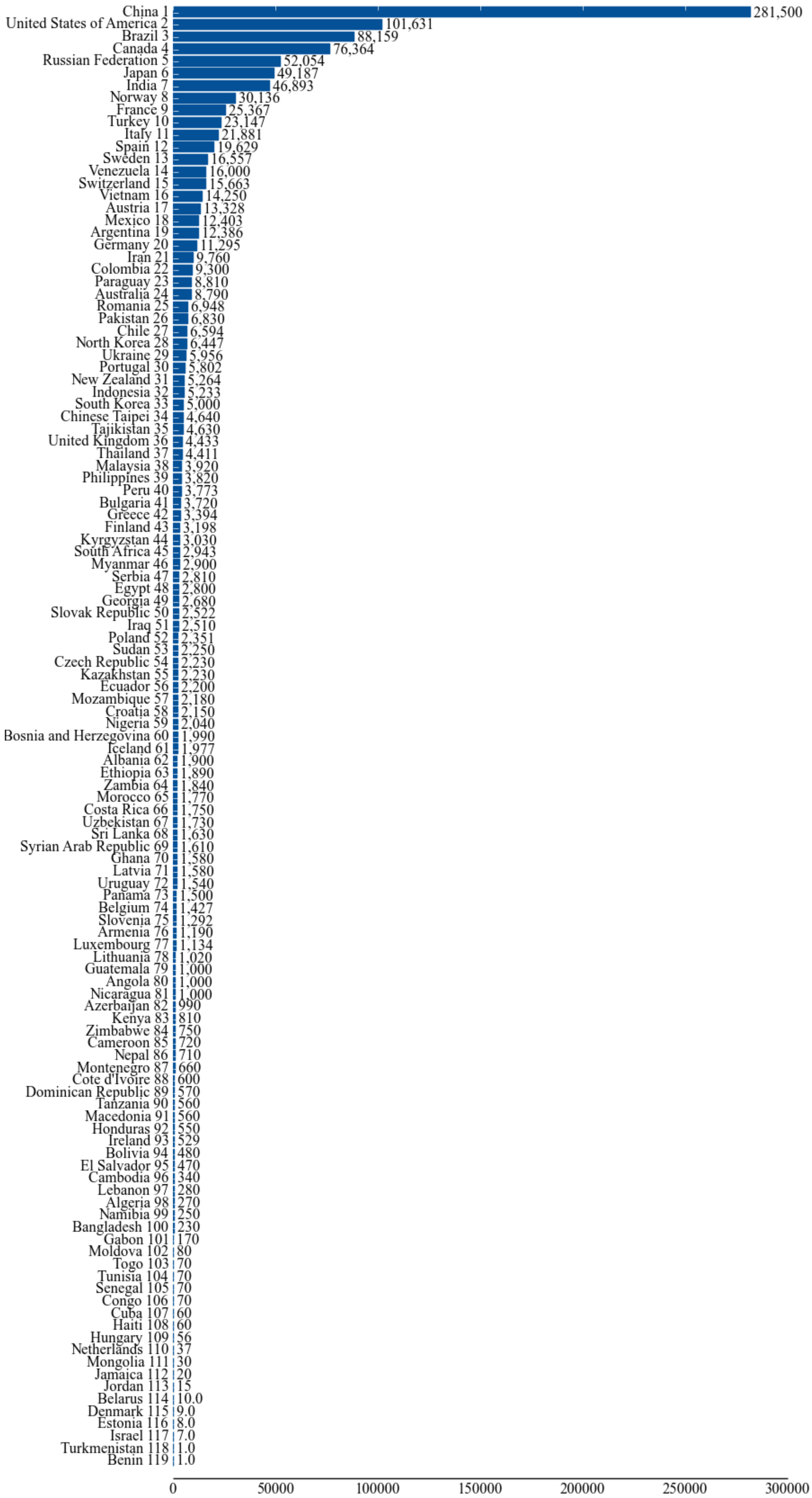
The average capacity factor of installed geothermal for electricity worldwide based on 2012 data is ~70.3% (IEA, 2015). However, this is not a technical or economic limit, and in a 100% WWS system the capacity factor for geothermal could be higher than this. Therefore, the roadmaps here assume that the capacity factor of geothermal will increase to 90.5% by 2050. They call for a 139-country-total of 96.6 GW of installed geothermal for electricity producing 87.0 GW of delivered power in 2050.

5.4. Hydropower

In 2012, conventional (small and large) hydropower provided ~16.5% of the world electric power supply (IEA, 2014a). 2014 installations of hydropower were ~1.143 TW (Figure 8). Given the world-averaged capacity factor for hydropower of ~41.8% in 2012 (IEA, 2014a), this implies hydropower delivered electricity in 2014 of ~477.8 GW (4185 TWh/yr).

Figure 8 shows the distribution of installed conventional hydropower by country. China, the United States, Brazil, and Canada lead in installations. However, the countries of the world with the greatest percentage of their electric power production from hydropower in 2012 include, in order: Albania (100%), Paraguay (100%), Montenegro (99.9%), Zambia (99.7%), Tajikistan (99.6%), Democratic Republic of the Congo (99.6%), Nepal (99.5%), Ethiopia (98.7%), Namibia (97.8%), Norway (96.7%), and the Kyrgyz Republic (93.5%). (World Bank, 2015). Thus, 7 countries already produce 99-100% of all their electricity from WWS hydropower. In fact, 22 countries produce more than 70% of all their electricity from hydropower and 36 produce more than 50%, of which 28 are developing countries.

Figure 8. Installed conventional hydropower by country in 2014 (IEA, 2014b; IHA, 2015).



China 1 281,500
United States of America 2 101,631
Brazil 3 88,159
Canada 4 76,364
Russian Federation 5 52,054
Japan 6 49,187
India 7 46,893
Norway 8 30,136
France 9 25,367
Turkey 10 23,147
Italy 11 21,881
Spain 12 19,629
Sweden 13 16,557
Venezuela 14 16,000
Switzerland 15 15,663
Vietnam 16 14,250
Austria 17 13,328
Mexico 18 12,403
Argentina 19 12,386
Germany 20 11,295
Iran 21 9,760
Colombia 22 9,300
Paraguay 23 8,810
Australia 24 8,790
Romania 25 6,948
Pakistan 26 6,830
Chile 27 6,594
North Korea 28 6,447
Ukraine 29 5,956
Portugal 30 5,802
New Zealand 31 5,264
Indonesia 32 5,233
South Korea 33 5,000
Chinese Taipei 34 4,640
Tajikistan 35 4,630
United Kingdom 36 4,433
Thailand 37 4,411
Malaysia 38 3,920
Philippines 39 3,820
Peru 40 3,773
Bulgaria 41 3,720
Greece 42 3,394
Finland 43 3,198
Kyrgyzstan 44 3,030
South Africa 45 2,943
Myanmar 46 2,900
Serbia 47 2,810
Egypt 48 2,800
Georgia 49 2,680
Slovak Republic 50 2,522
Iraq 51 2,510
Poland 52 2,351
Sudan 53 2,250
Czech Republic 54 2,230
Kazakhstan 55 2,230
Ecuador 56 2,200
Mozambique 57 2,180
Croatia 58 2,150
Nigeria 59 2,040
Bosnia and Herzegovina 60 1,990
Iceland 61 1,977
Albania 62 1,900
Ethiopia 63 1,890
Zambia 64 1,840
Morocco 65 1,770
Costa Rica 66 1,750
Uzbekistan 67 1,730
Sri Lanka 68 1,630
Syrian Arab Republic 69 1,610
Ghana 70 1,580
Latvia 71 1,580
Uruguay 72 1,540
Panama 73 1,500
Belgium 74 1,427
Slovenia 75 1,292
Armenia 76 1,190
Luxembourg 77 1,134
Lithuania 78 1,020
Guatemala 79 1,000
Angola 80 1,000
Nicaragua 81 1,000
Azerbaijan 82 990
Kenya 83 810
Zimbabwe 84 750
Cameroon 85 720
Nepal 86 710
Montenegro 87 660
Cote d'Ivoire 88 600
Dominican Republic 89 570
Tanzania 90 560
Macedonia 91 560
Honduras 92 550
Ireland 93 529
Bolivia 94 480
El Salvador 95 470
Cambodia 96 340
Lebanon 97 280
Algeria 98 270
Namibia 99 250
Bangladesh 100 230
Gabon 101 170
Moldova 102 80
Togo 103 70
Tunisia 104 70
Senegal 105 70
Congo 106 70
Cuba 107 60
Haiti 108 60
Hungary 109 56
Netherlands 110 37
Mongolia 111 30
Jamaica 112 20
Jordan 113 15
Belarus 114 10.0
Denmark 115 9.0
Estonia 116 8.0
Israel 117 7.0
Turkmenistan 118 1.0
Benin 119 1.0
0
50000
100000
150000
200000
250000
300000
Installed 2014 hydro capacity (MW)

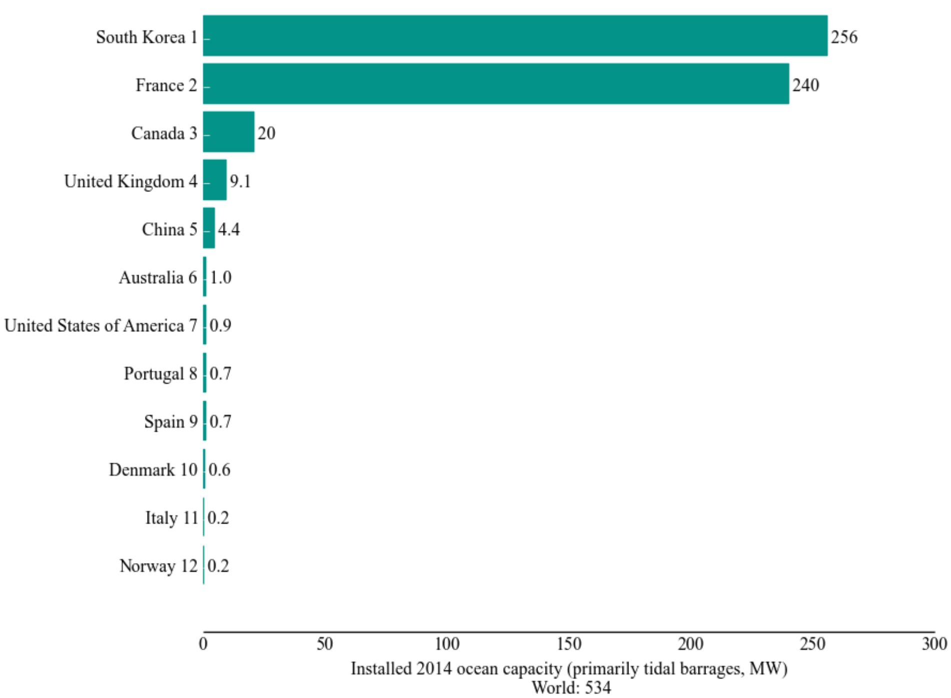
Under the roadmaps proposed here, conventional hydropower will supply ~4.8% (570.4 GW) of the 139-country 2050 end-use power demand for all purposes (Table 2). However, no new hydropower dams are proposed for installation. Instead, the capacity factor of hydropower will be increased from a 139-country average of ~41.8% to 50% by 2050. Increasing the capacity factor is feasible because existing dams currently produce less than their maximum capacity, mainly because many other dispatchable sources of electricity exist in the current energy system, greatly reducing the need for hydropower to balance supply and demand. However, in some cases, hydropower is not used to its full extent because of other priorities affecting water use, and in a 100% WWS system, these other priorities will remain.

Whereas, increasing hydropower capacity factors should be possible, if it is not, additional hydropower capacity can be obtained by powering presently non-powered dams. The U.S., for example, has over 80,000 dams that are not powered at present. Although only a small fraction of these dams can feasibly be powered, DOE (2012) estimates that the potential amounts to ~12 GW of capacity in the contiguous 48 states.

5.5. Tidal and Wave

Worldwide by the end of 2014, a total of ~534 MW of ocean devices (mostly tidal barrages) had been installed. Figure 9 indicates these are mostly from two large plants in South Korea and France and smaller plants in Canada and the United Kingdom.

Figure 9. Installed ocean power by country in 2014 (IEA 2014b). Ocean power includes tidal rise and fall, ocean and tidal currents, wave power, ocean thermal energy conversion, and salinity gradients. Nearly all existing capacity in the figure arises from tidal barrages.



Under the roadmaps here, tidal is proposed to contribute ~0.068%, or ~8.03 GW, of the 139-country end-use delivered power in 2050 (Table 2). This requires a nameplate capacity of ~32.6 GW installed of which ~1.6% has been installed as of the end of 2014. The needed nameplate capacity is much less than the estimated world technical potential of ~556 GW installed (1200 TWh/yr or 137 GW delivered power) (Marine Renewables Canada, 2015). Some countries with significant tidal potential include Australia (3.8 GW nameplate capacity), Canada (171 GW), France (16 GW), Ireland (107 GW), Japan (3 GW), United Kingdom (8 GW), and the United States (116 GW) (Marine Renewables Canada, 2015).

Wave power is proposed here to contribute ~0.72%, or ~85.3 GW, of the 139-country end-use power demand in 2050 (Table 2). This requires a nameplate installation of ~372 GW, which is much less than the world technical potential for the 139 countries considered of ~4.362 GW installed (8,850 TWh/yr, or 1010 GW delivered) (Marine Renewables Canada, 2015 but assuming 70% exclusion zones). Some of countries with significant wave potential include Australia (192 GW installed), Canada (275 GW), France (14 GW), Japan (13 GW), Ireland (3 GW), Norway (59 GW), United Kingdom (6 GW), and the United States (263 GW) (Marine Renewables Canada, 2015).

6. Matching Electric Power Supply with Demand

An important requirement for 100% WWS roadmaps is that the grid remains reliable. To that end, Jacobson et al. (2015b) developed and applied a grid integration model to determine the quantities and costs of storage devices needed to ensure that a 100% WWS system developed for each of the 48 contiguous U.S. states, when integrated across all such states, could match load without loss every 30 s for 6 years (2050-2055) while accounting for the variability and uncertainty of WWS resources.

Wind and solar time-series were derived from 3-D global model simulations that accounted for extreme events and competition among wind turbines for kinetic energy and the feedback of extracted solar radiation to roof and surface temperatures. Solutions were obtained by prioritizing storage for excess heat (in soil and water) and electricity (in ice, water, phase-change material tied to CSP, pumped hydro, and hydrogen), using hydropower only as a last resort, and using demand response to shave periods of excess demand over supply.

No stationary storage batteries, biomass, nuclear power, or natural gas were needed. Frequency regulation of the grid was provided by ramping up/down hydropower, stored CSP or pumped hydro; ramping down other WWS generators and storing the electricity in heat, cold, or hydrogen instead of curtailment; and using demand response.

Multiple low-cost stable solutions to the grid integration problem across the 48 contiguous U.S. states were obtained, suggesting that maintaining grid reliability upon 100% conversion to WWS in that region is a solvable problem. The mean U.S.-averaged levelized cost of energy in that study, accounting for storage transmission, distribution, maintenance, and array losses, was ~10.6 ¢/kWh for electricity and ~11.4 ¢/kWh for all energy in 2013 dollars.

For the 139-country roadmaps here, similar grid integration studies are being performed (Jacobson et al., 2016b). For these studies, the 139 countries are divided into 20 groups of countries or individual island countries where both time-dependent demand for and supply of WWS energy are aggregated for use in the same grid integration model as was used in the 50-state study. Additional CSP and solar thermal collectors for peaking/storage are also being added to each country's energy supply to help firm the grid, as in that study. Geothermal heat in 2014 by country is assumed also to exist in 2050, enhancing the ability of the entire heat and power system to remain stable. For each region, electricity storage and heat/cold storage are being used. Stable solutions have been obtained to date for all 20 regions and countries suggesting grid reliability is not a barrier to 100% clean, renewable WWS energy systems in the 139 countries considered.

7. Costs of Electric Power Generation

In this section, current and future full social costs (including capital, land, operating, maintenance, storage, fuel, transmission, and externality costs) of WWS electric power generators versus non-WWS conventional fuel generators are estimated. These costs do not include the costs of storage necessary to keep the grid stable, which are being quantified in Jacobson et al. (2016b), except for the cost of storage associated with CSP, which is included here. The estimates here are based on current cost data and trend projections for individual generator types. The estimates are only a rough approximation of costs in a future optimized renewable energy system.

Table 5 presents 2013 and 2050 139-country weighted average estimates of fully annualized levelized business costs of electric power generation for conventional fuels and WWS technologies. The table indicates that the 2013 business costs of hydropower, onshore wind, utility-scale solar PV, and solar thermal for heat are already similar to or less than the costs of natural gas combined cycle. Residential and commercial PV, offshore wind, tidal, and wave are more expensive. However, residential rooftop PV costs are given as if PV is purchased for an individual household. A common business model today is where multiple households contract together with a solar provider to decrease the average cost.

By 2050, the costs of all WWS technologies are expected to drop, most significantly for offshore wind, tidal, wave, rooftop PV, CSP, and utility PV, whereas conventional fuel costs are expected to rise. Because WWS technologies have zero fuel costs, the drop in their costs over time is due primarily to technology improvements. WWS costs are expected to decline also due to less expensive manufacturing and streamlined project deployment from increased economies of scale. Conventional fuels, on the other hand, face rising costs over time due to higher labor and transport costs for mining, transporting, and processing fuels continuously over the lifetime of fossil-fuel plants.

Table 5. Approximate fully annualized, unsubsidized 2013 and 2050 U.S.-averaged costs of delivered electricity, including generation, short- and long-distance transmission, distribution, and storage, but not including external costs, for conventional fuels and WWS power (2013 U.S. $/kWh-delivered).

Technology	Technology year 2013			Technology year 2050		
	LCHB	*HCLB*	*Average*	*LCHB*	*HCLB*	*Average*
Advanced pulverized coal	0.083	0.113	0.098	0.079	0.107	0.093
Advanced pulverized coal w/CC	0.116	0.179	0.148	0.101	0.151	0.126
IGCC coal	0.094	0.132	0.113	0.084	0.115	0.100

IGCC coal w/CC	0.144	0.249	0.197	0.098	0.146	0.122
Diesel generator (for steam turb.)	0.187	0.255	0.221	0.250	0.389	0.319
Gas combustion turbine	0.191	0.429	0.310	0.193	0.404	0.299
Combined cycle conventional	0.082	0.097	0.090	0.105	0.137	0.121
Combined cycle advanced	n.a.	n.a.	n.a.	0.096	0.119	0.108
Combined cycle advanced w/CC	n.a.	n.a.	n.a.	0.112	0.143	0.128
Fuel cell (using natural gas)	0.122	0.200	0.161	0.133	0.206	0.170
Microturbine (using natural gas)	0.123	0.149	0.136	0.152	0.194	0.173
Nuclear, APWR	0.082	0.143	0.112	0.073	0.121	0.097
Nuclear, SMR	0.095	0.141	0.118	0.080	0.114	0.097
Distributed gen. (using natural gas)	n.a.	n.a.	n.a.	0.254	0.424	0.339
Municipal solid waste	0.204	0.280	0.242	0.180	0.228	0.204
Biomass direct	0.132	0.181	0.156	0.105	0.133	0.119
Geothermal	0.087	0.139	0.113	0.081	0.131	0.106
Hydropower	0.063	0.096	0.080	0.055	0.093	0.074
On-shore wind	0.076	0.108	0.092	0.064	0.101	0.082
Off-shore wind	0.111	0.216	0.164	0.093	0.185	0.139
CSP no storage	0.131	0.225	0.178	0.091	0.174	0.132
CSP with storage	0.081	0.131	0.106	0.061	0.111	0.086
PV utility crystalline tracking	0.073	0.107	0.090	0.061	0.091	0.076
PV utility crystalline fixed	0.078	0.118	0.098	0.063	0.098	0.080
PV utility thin-film tracking	0.073	0.104	0.089	0.061	0.090	0.075
PV utility thin-film fixed	0.077	0.118	0.098	0.062	0.098	0.080
PV commercial rooftop	0.098	0.164	0.131	0.072	0.122	0.097
PV residential rooftop	0.130	0.225	0.177	0.080	0.146	0.113
Wave power	0.276	0.661	0.468	0.156	0.407	0.282
Tidal power	0.147	0.335	0.241	0.084	0.200	0.142
Solar thermal for heat ($/kWh-th)	0.057	0.070	0.064	0.051	0.074	0.063

LCHB = low cost, high benefits case; HCLB = high cost, low benefits case. The methodology for calculating the costs is described in Jacobson et al. (2015a).

For the year 2050 100% WWS scenario, costs are shown for WWS technologies; for the year 2050 BAU case, costs of WWS are slightly different. The costs assume $0.0115 (0.11-0.12)/kWh for standard (but not extra-long-distance) transmission for all technologies except rooftop solar PV (to which no transmission cost is assigned) and $0.0257 (0.025-0.0264)/kWh for distribution for all technologies. Transmission and distribution losses are accounted for in the energy available.

CC = carbon capture; IGCC = integrated gasification combined cycle; AWPR = advanced pressurized-water reactor; SMR = small modular reactor; PV = photovoltaics.

CSP w/storage assumes a maximum charge to discharge rate (storage size to generator size ratio) of 2.62:1.

Solar thermal for heat assumes $3,600-$4,000 per 3.716 m^2 collector and 0.7 kW-th/m^2 maximum power (Jacobson et al., 2015a).

Table 5 does not include externality costs. These are estimated as follows. The 2050 139-country air pollution cost (Table 7) plus global climate cost (Table 8) per unit energy (converted to kWh) produced in all sectors in all countries in the 2050 BAU case (Table 1) corresponds to a mean 2050 externality cost (in 2013 dollars) due to conventional fuels of ~$0.24 (0.082-0.62)/kWh, with $0.15 (0.02-0.41)/kWh due to air pollution impacts and the rest due to climate impacts. The mean air pollution cost is in the middle of the $0.014-$0.17/kWh range from Buonocore et al. (2015). Externality costs arise due to air pollution morbidity and mortality and global warming damage (e.g. coastline losses, fishery losses, agricultural losses, heat stress mortality and morbidity, famine, drought, wildfires, and severe weather) due to conventional fuels. When externality costs are added to the business costs of conventional fuels, all WWS technologies cost less than conventional technologies in 2050.

Table 6 provides the mean value of the 2013 and 2050 LCOEs weighted among all conventional generators (BAU cases) and WWS generators (WWS case) by country. The table also gives the 2050 energy, health, and global climate cost savings per person. The electric power cost of WWS in 2050 is not directly comparable with the BAU electric power cost, because the latter does not integrate transportation, heating/cooling, or industry energy costs. Conventional vehicle fuel costs, for example, are a factor of 4-5 higher than those of electric vehicles, yet the cost of BAU electricity cost in 2050 does not include the transportation cost, whereas the WWS electricity cost does. Nevertheless, based on the comparison, WWS energy in 2050 will save the average 139-country consumer $170/yr in energy costs ($2013 dollars).

In addition, WWS will save $2,880/yr in health costs, and $1,930/yr in global climate costs. The total up-front capital cost of the 2050 WWS system (for both average annual power and peaking storage in Table 2) for the 139 countries is ~$100 trillion for the 49.2 TW of installed capacity needed (~$2.03 million/MW).

Table 6. Mean values of the levelized cost of energy (LCOE) for conventional fuels (BAU) in 2013 and 2050 and for WWS fuels in 2050. The LCOE estimates do not include externality costs. The 2013 and 2050 values are used to calculate energy cost savings per person per year in each country (see footnotes). Health and climate cost savings per person per year are derived from data in Section 8. All costs are in 2013 dollars.

Country	(a) 2013 LCOE of BAU (¢/kWh)	(b) 2050 LCOE of BAU (¢/kWh)	(c) 2050 LCOE of WWS (¢/kWh)	(d) 2050 Average electricity cost savings per person per year ($/per-son/yr)	(e) 2050 Average air quality health cost savings per person per year due to WWS ($/person/yr)	(f) 2050 Average climate cost savings to world per person per year due to WWS ($/person/yr)	(g) 2050 Average energy + health + world climate cost savings due to WWS ($/person/yr)
Albania	7.98	6.90	6.92	82	1,823	818	2,723
Algeria	8.95	12.01	7.28	157	1,203	1,618	2,977
Angola	8.26	8.40	13.63	-9	2,289	340	2,619
Argentina	9.07	10.68	10.60	83	1,376	1,837	3,296
Armenia	9.60	9.50	5.89	175	3,560	676	4,411
Australia	10.83	10.37	8.49	418	776	5,871	7,064
Austria	9.55	9.17	6.45	456	4,311	4,162	8,929
Azerbaijan	8.83	11.38	7.72	226	3,877	2,341	6,444
Bahrain	8.96	12.06	7.29	1,419	2,363	6,739	10,522
Bangladesh	8.99	11.93	6.90	28	2,220	130	2,378
Belarus	8.97	12.04	6.35	699	10,935	4,030	15,664
Belgium	11.31	10.70	6.88	581	4,570	5,003	10,155
Benin	9.02	12.08	6.19	10	2,475	123	2,608
Bolivia	8.94	10.48	8.69	22	542	573	1,138
Bosnia and Herzegovina	10.34	9.07	6.37	229	2,323	4,096	6,648
Botswana	11.33	9.94	7.25	131	1,186	896	2,213
Brazil	8.87	7.97	8.07	70	515	923	1,508
Brunei Darussalam	8.98	12.07	6.83	1,310	258	8,257	9,825
Bulgaria	11.30	9.85	5.78	950	6,253	4,457	11,660
Cambodia	9.19	11.84	9.92	15	802	110	926
Cameroon	8.32	8.29	5.85	19	2,492	108	2,619
Canada	9.35	8.48	9.89	164	2,616	6,109	8,888
Chile	10.03	10.01	9.12	288	1,588	2,302	4,178
China	10.91	9.62	7.40	342	5,329	3,823	9,494
Chinese Taipei	10.91	9.62	10.19	376	5,647	6,553	12,576

Colombia	8.56	8.01	6.49	40	253	784	1,078
Congo	8.36	8.90	9.19	7	1,132	122	1,260
Congo, Dem. Republic	7.99	6.93	5.00	4	489	10	504
Costa Rica	9.89	8.89	9.68	23	148	650	821
Cote d'Ivoire	8.75	10.58	7.28	21	396	83	500
Croatia	9.33	9.45	6.54	437	4,934	2,654	8,025
Cuba	5.43	7.05	9.60	-18	625	2,147	2,755
Cyprus	9.28	12.17	8.54	452	3,867	2,749	7,068
Czech Republic	11.75	10.10	6.00	524	5,041	5,901	11,466
Denmark	13.21	12.15	12.92	145	4,757	3,599	8,500
Dominican Republic	9.24	11.14	10.39	40	366	797	1,203
Ecuador	8.66	9.30	8.78	28	290	862	1,180
Egypt	9.00	11.68	8.15	171	1,835	777	2,783
El Salvador	11.36	11.21	9.82	42	195	509	746
Eritrea	9.02	12.08	11.76	2	1,110	27	1,140
Estonia	11.75	10.36	8.52	586	7,530	10,902	19,018
Ethiopia	8.02	6.96	7.39	0	758	12	770
Finland	10.69	9.62	9.83	335	6,360	5,226	11,921
France	11.48	9.70	10.18	159	3,191	2,462	5,813
Gabon	8.55	9.70	7.23	65	1,147	421	1,632
Georgia	8.20	8.06	7.64	90	3,523	808	4,421
Germany	11.91	10.87	7.50	656	5,189	5,296	11,141
Ghana	7.56	7.59	6.51	14	2,790	121	2,924
Gibraltar	11.44	11.22	6.20	18	8,331	8,139	16,489
Greece	10.74	10.79	8.21	379	3,634	3,684	7,696
Guatemala	11.28	10.51	9.11	18	216	245	478
Haiti	9.17	11.33	9.98	2	215	79	296
Honduras	8.97	10.10	8.61	23	92	312	427
Hong Kong, China	10.65	10.55	6.98	1,176	8,517	3,165	12,857
Hungary	11.19	10.74	4.91	396	5,518	2,431	8,345
Iceland	10.63	9.13	9.84	286	1,016	2,798	4,100
India	10.97	10.05	7.44	70	3,234	726	4,030
Indonesia	10.39	10.91	7.50	80	603	773	1,457
Iran, Islamic Republic	8.93	11.80	6.59	249	1,750	3,052	5,051
Iraq	7.33	9.57	7.65	26	1,299	1,088	2,413
Ireland	10.12	11.11	11.55	93	1,591	2,897	4,581
Israel	10.38	10.80	7.25	354	2,434	3,300	6,088
Italy	10.20	11.17	6.92	486	3,522	2,868	6,876
Jamaica	9.49	12.14	10.65	50	206	1,007	1,263
Japan	9.72	10.36	7.49	429	2,598	5,806	8,833
Jordan	8.97	12.04	8.02	139	761	1,000	1,899
Kazakhstan	10.79	9.87	8.52	284	3,912	6,913	11,109
Kenya	10.57	10.49	8.42	10	357	94	461
Korea, Dem. People's Rep.	9.22	8.14	7.83	19	1,048	1,417	2,484
Korea, Republic of	10.87	10.39	6.35	1,136	2,965	7,089	11,190
Kosovo	11.26	9.89	8.02	297	1,036	2,833	4,165
Kuwait	8.96	12.06	6.44	2,197	2,078	13,008	17,283
Kyrgyzstan	8.12	7.18	6.79	47	1,239	393	1,679
Latvia	8.77	9.71	7.76	405	12,538	2,390	15,334
Lebanon	8.91	11.81	7.45	282	1,435	2,629	4,346
Libya	8.96	12.06	8.40	240	683	2,748	3,671
Lithuania	9.61	11.19	9.07	373	12,373	2,315	15,061
Luxembourg	9.35	11.88	5.23	950	6,136	7,403	14,489
Macedonia, Republic of	10.58	9.36	7.47	321	2,462	2,767	5,550
Malaysia	9.95	10.92	6.69	464	448	2,667	3,579
Malta	9.00	12.06	7.63	695	4,497	3,251	8,442
Mexico	9.52	11.21	8.25	232	676	1,573	2,482
Moldova, Republic of	8.90	11.74	7.45	305	5,774	1,067	7,146
Mongolia	11.21	10.04	7.26	108	1,237	1,443	2,789

Montenegro	9.81	8.56	8.07	210	279	2,275	2,765
Morocco	10.25	10.76	8.47	78	1,138	621	1,837
Mozambique	7.98	6.90	8.19	-2	256	27	281
Myanmar	8.45	8.27	8.68	3	1,852	72	1,927
Namibia	8.03	6.96	7.47	1	1,379	761	2,142
Nepal	7.98	6.90	6.35	3	1,796	46	1,846
Netherlands	10.40	11.65	11.19	224	4,392	4,599	9,215
Netherlands Antilles	7.92	9.47	7.59	74	360	5,872	6,306
New Zealand	10.22	9.62	9.34	199	346	3,111	3,656
Nicaragua	10.81	12.13	8.92	40	119	317	475
Nigeria	8.76	10.98	6.17	13	6,830	103	6,947
Norway	8.12	7.16	8.00	221	4,629	5,825	10,674
Oman	8.96	12.06	7.41	482	9,501	5,470	15,453
Pakistan	8.82	10.37	6.79	37	3,150	282	3,469
Panama	8.64	9.25	8.07	74	128	966	1,169
Paraguay	7.98	6.90	7.13	21	539	282	843
Peru	8.62	9.24	8.53	31	490	877	1,398
Philippines	10.96	10.99	11.48	21	176	271	468
Poland	11.56	10.32	9.91	184	5,365	4,849	10,398
Portugal	11.25	11.15	9.76	130	3,407	2,611	6,149
Qatar	8.96	12.06	7.08	1,253	1,500	17,054	19,807
Romania	10.44	9.60	8.34	216	6,883	2,088	9,186
Russian Federation	9.61	10.48	10.15	523	10,055	8,289	18,866
Saudi Arabia	6.26	8.42	6.24	429	1,761	6,444	8,634
Senegal	8.90	11.48	8.46	15	3,508	137	3,660
Serbia	10.53	9.28	6.25	536	5,505	3,234	9,275
Singapore	9.05	11.97	7.13	945	1,102	1,015	3,063
Slovak Republic	11.06	9.83	6.66	329	4,969	3,431	8,729
Slovenia	10.82	9.32	6.70	439	4,118	4,841	9,398
South Africa	11.35	9.92	7.31	549	1,605	4,528	6,682
Spain	11.44	11.22	8.43	288	3,410	2,283	5,981
Sri Lanka	8.89	9.86	10.05	20	750	289	1,058
Sudan	8.22	8.18	8.48	3	3,062	78	3,143
Sweden	10.58	8.95	9.14	277	5,419	2,481	8,177
Switzerland	9.73	8.24	6.28	338	2,780	2,757	5,875
Syrian Arab Republic	8.88	11.65	8.19	76	762	953	1,792
Tajikistan	7.99	6.96	7.83	-1	1,353	115	1,468
Tanzania, United Republic	8.50	9.49	7.14	7	295	54	357
Thailand	9.67	11.39	6.76	412	2,080	2,347	4,839
Togo	8.35	8.28	6.18	6	1,829	52	1,887
Trinidad and Tobago	8.96	12.06	8.31	759	818	23,862	25,439
Tunisia	9.02	12.06	7.43	239	1,168	1,106	2,513
Turkey	9.64	10.34	7.30	115	1,617	1,609	3,341
Turkmenistan	8.96	12.06	6.35	255	3,202	4,085	7,541
Ukraine	11.13	9.84	9.55	278	8,451	4,489	13,218
United Arab Emirates	8.96	12.06	6.73	1,440	2,077	11,527	15,044
United Kingdom	10.85	11.07	13.09	46	3,238	3,244	6,527
United States of America	10.84	10.39	8.48	443	1,390	6,186	8,020
Uruguay	9.16	9.11	9.29	72	1,098	958	2,129
Uzbekistan	8.87	10.97	5.78	163	1,805	1,466	3,433
Venezuela	8.29	8.52	7.41	102	241	2,741	3,083
Vietnam	9.17	10.06	8.94	67	1,093	760	1,920
Yemen	8.96	12.06	8.77	9	1,479	257	1,745
Zambia	7.98	6.91	6.78	8	762	33	803
Zimbabwe	8.90	7.75	6.46	24	579	179	782
World total or average	**10.28**	**10.10**	**7.94**	**170**	**2,882**	**1,930**	**4,982**

a) The 2013 LCOE cost for conventional fuels in each country combines the estimated distribution of conventional and WWS generators in 2013 with 2013 mean LCOEs for each generator from Table 5. Costs include all-distance transmission, pipelines, and distribution, but they exclude externalities.

b) Same as (a), but for a 2050 BAU case (Supplemental Information) and 2050 LCOEs for each generator from Table 5. The 2050 BAU case includes significant existing WWS (mostly hydropower) plus future increases in WWS and energy efficiency.
c) The 2050 LCOE of WWS in the country combines the 2050 distribution of WWS generators from Table 3 with the 2050 mean LCOEs for each WWS generator from Table 5. The LCOE accounts for all-distance transmission and distribution (footnotes to Tables 2 and 5).
d) The total cost of electricity use in the electricity sector in the BAU (the product of electricity use and the LCOE) less the total cost in the electricity sector in the WWS scenario and less the annualized cost of the assumed efficiency improvements in the electricity sector in the WWS scenario. (See Delucchi et al., 2015 for details.)
e) Total cost of air pollution per year in the country from Table 7 divided by the 2050 population of the country.
f) Total climate cost per year to the world due to country's emissions (Table 8) divided by the 2050 population of the country.
g) The sum of columns (d), (e), and (f).

8. Air Pollution and Global Warming Damage Costs Eliminated by WWS

Conversion to a 100% WWS energy infrastructure in the 139 countries will eliminate energy-related air pollution mortality and morbidity and the associated health costs, and it will eliminate energy-related climate change costs to the world while causing variable climate impacts on individual countries. This section discusses these topics.

8.A. Air Pollution Cost Reductions due to WWS

The benefits of reducing air pollution mortality and its costs in each U.S. country can be quantified as follows.

First, the premature human mortality rate worldwide due to cardiovascular disease, respiratory disease, and complications from asthma arising from air pollution has been estimated previously by combining computer model estimates of human exposure to particulate matter ($PM_{2.5}$) and ozone (O_3) with the relative risk of mortality from these chemicals and population. Results are that an estimated 4-7 million people currently perish prematurely each year worldwide from outdoor plus indoor air pollution (e.g., Shindell et al., 2012; Anenberg et al., 2012; WHO, 2014; OECD, 2014). These mortalities represent ~0.7-1.2% of the 570 million deaths/year worldwide in 2015. Here, we combine modeled concentrations of $PM_{2.5}$ and O_3 in each of 139 countries with the relative risk of mortality as a function of concentration and with population in a health-effects equation (e.g., Jacobson, 2010) to estimate low, medium, and high mortalities due to $PM_{2.5}$ and O_3 by country, then extrapolate the results forward to 2050 while accounting for efficiencies that occur under the BAU scenario.

Figure 10 shows the results. Premature mortalities in 2014, summed over the 139 countries are estimated for $PM_{2.5}$ to be ~4.28 (1.19-7.56) million/yr, and those for O_3, ~279,000 (140,000-417,000)/yr. The sum is ~4.56 (1.33-7.98) million premature mortalities/yr for $PM_{2.5}$ plus O_3, which is in the range of the previous literature estimates.

Figure 10. Modeled worldwide (all countries, including the 139 discussed in this paper) (a) $PM_{2.5}$ and (b) O_3 premature mortalities in 2014 as estimated with GATOR-GCMOM (Jacobson, 2010), a 3-dimensional global computer model.

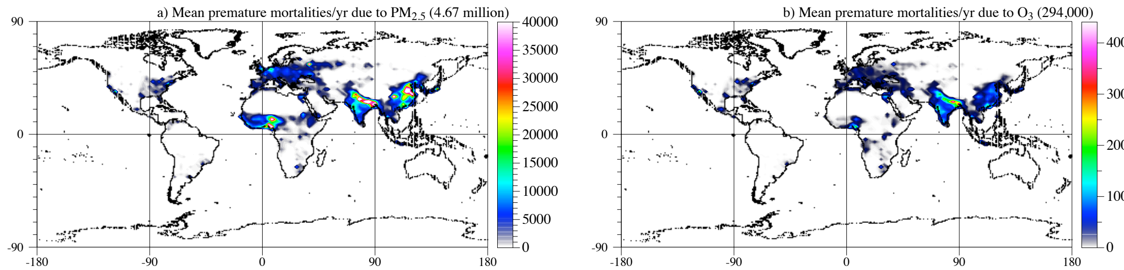


Table 7 shows estimated air pollution mortality avoided by country in 2050 due to conversion to WWS, projected forward from 2014 with the methodology detailed in Delucchi et al. (2015). This method projects future pollution from current levels with an estimated annual rate of pollution change that considers increasing emission controls and more sources over time. The number of mortalities in 2050 then accounts for the growth of population by country and a nonlinear relationship between exposure and population. The resulting number of 2050 air pollution mortalities avoided in the 139 countries due to WWS is estimated at 3.3 (0.8-7.0) million/yr.

Table 7. Avoided air pollution $PM_{2.5}$ plus ozone premature mortalities by country in 2050 and mean avoided costs (in 2013 dollars) from mortalities and morbidities.

Country	2050 High avoided premature mortalities/yr	2050 Mean avoided premature mortalities/yr	2050 Low avoided premature mortalities/yr	2014 Mean avoided cost ($2013 mil./yr)	2050 Mean avoided cost as percent of 2050 GDP
Albania	1,197	538	140	5,149	3.8
Algeria	16,035	7,214	1,817	53,137	4.2
Angola	43,242	18,694	4,486	105,016	13.8
Argentina	19,230	8,155	1,751	73,633	3.2
Armenia	2,736	1,223	297	10,477	9.2
Australia	4,759	1,988	430	22,501	1.2
Austria	6,139	2,707	637	32,420	5.7
Azerbaijan	8,298	3,715	887	43,463	5.4
Bahrain	1,016	494	122	4,365	5.7
Bangladesh	264,472	123,340	29,114	555,430	20.8
Belarus	15,715	7,125	1,621	84,624	14.7
Belgium	8,900	3,881	863	45,162	6.4
Benin	33,188	16,812	4,188	54,740	44.4
Bolivia	3,811	1,606	344	8,675	3.5
Bosnia and Herzegovina	2,193	969	236	9,042	5.1
Botswana	1,021	439	102	3,404	3.7
Brazil	36,341	15,305	3,342	134,206	1.3
Brunei Darussalam	24	10	2	165	0.2
Bulgaria	5,665	2,527	600	29,083	9.0
Cambodia	9,036	3,911	910	17,913	7.3
Cameroon	45,570	22,149	5,310	86,992	30.7
Canada	22,214	9,598	2,188	107,607	4.0
Chile	6,910	2,981	652	30,794	2.8
China	1,349,179	624,262	145,129	6,947,983	8.2
Chinese Taipei	13,773	6,164	1,464	113,841	3.1
Colombia	4,753	1,986	428	14,222	0.9
Congo	4,736	2,049	472	10,865	7.7
Congo, Dem. Republic	72,332	31,482	7,199	70,878	18.4
Costa Rica	281	120	29	900	0.5
Cote d'Ivoire	8,660	3,603	760	14,711	4.5
Croatia	3,430	1,514	362	19,066	5.9

Cuba	1,495	659	167	5,727	1.6
Cyprus	817	365	90	5,384	3.4
Czech Republic	9,628	4,267	974	43,051	9.4
Denmark	5,128	2,238	504	26,518	6.4
Dominican Republic	1,592	701	182	5,009	1.4
Ecuador	2,154	913	206	6,127	1.2
Egypt	83,713	38,708	9,474	253,029	8.2
El Salvador	460	204	53	1,208	1.1
Eritrea	9,097	4,205	973	12,639	23.4
Estonia	1,481	671	153	6,491	15.3
Ethiopia	163,820	70,820	15,764	210,895	16.2
Finland	6,059	2,697	600	30,653	9.4
France	45,497	19,875	4,574	222,658	4.8
Gabon	1,061	446	96	3,704	3.2
Georgia	3,569	1,597	387	13,336	9.6
Germany	71,015	31,132	7,044	371,196	6.9
Ghana	50,372	25,133	6,169	112,266	26.6
Gibraltar	41	18	4	233	9.9
Greece	8,668	3,852	947	36,467	7.7
Guatemala	2,000	875	226	4,958	1.3
Haiti	2,070	913	238	2,873	4.1
Honduras	604	257	61	1,197	0.8
Hong Kong, China	7,913	3,677	873	52,575	7.9
Hungary	11,294	5,023	1,154	46,848	12.1
Iceland	70	31	8	357	1.4
India	1,586,512	767,247	186,459	5,356,599	12.6
Indonesia	61,331	26,207	5,987	192,385	2.1
Iran, Islamic Republic	64,875	29,850	7,280	175,064	9.7
Iraq	28,542	13,116	3,283	73,153	7.9
Ireland	1,927	821	187	10,078	2.0
Israel	5,561	2,526	618	26,351	4.3
Italy	45,774	20,246	4,992	216,301	5.9
Jamaica	262	118	33	731	1.0
Japan	66,619	28,833	6,481	278,536	5.3
Jordan	3,645	1,650	410	8,551	5.4
Kazakhstan	14,842	6,528	1,522	86,985	4.2
Kenya	15,196	6,450	1,453	25,276	4.4
Korea, Dem. People's Rep.	19,725	8,743	1,958	28,276	19.1
Korea, Republic of	27,371	12,095	2,690	128,594	5.0
Kosovo	354	250	143	1,549	5.1
Kuwait	1,526	723	180	8,026	3.2
Kyrgyzstan	3,862	1,704	408	10,209	6.6
Latvia	3,190	1,469	338	19,359	13.7
Lebanon	2,183	991	247	5,964	7.5
Libya	2,175	970	249	7,426	2.2
Lithuania	5,380	2,479	570	34,495	12.1
Luxembourg	642	277	61	4,424	4.6
Macedonia, Republic of	1,072	474	118	4,902	4.4
Malaysia	4,247	1,849	464	19,215	0.8
Malta	266	120	31	1,781	3.9
Mexico	24,913	10,925	2,698	100,026	1.5
Moldova, Republic of	4,038	1,851	428	13,054	22.1
Mongolia	1,585	695	166	5,370	3.9
Montenegro	35	15	3	161	0.4
Morocco	18,808	8,485	2,080	47,840	6.8
Mozambique	13,580	5,660	1,272	15,102	6.8
Myanmar	59,875	26,143	5,920	133,475	13.5
Namibia	1,065	468	113	2,965	6.5
Nepal	43,866	20,502	4,840	82,607	21.0

Netherlands	14,933	6,487	1,435	78,642	5.7
Netherlands Antilles	36	15	3	145	0.7
New Zealand	352	148	34	1,797	0.4
Nicaragua	372	159	37	858	0.8
Nigeria	900,528	472,188	121,680	2,748,708	38.3
Norway	3,760	1,649	383	22,986	4.5
Oman	12,147	6,011	1,481	51,325	24.8
Pakistan	341,378	170,517	42,461	916,166	20.7
Panama	169	73	18	624	0.3
Paraguay	1,846	784	173	4,768	2.8
Peru	6,293	2,641	562	18,108	2.0
Philippines	11,351	4,855	1,159	30,223	0.9
Poland	40,913	18,348	4,172	172,136	11.6
Portugal	7,933	3,487	817	33,845	6.9
Qatar	543	271	68	3,839	1.4
Romania	22,892	10,184	2,351	124,304	8.8
Russian Federation	229,017	104,097	23,877	1,097,847	17.2
Saudi Arabia	15,938	7,598	1,855	70,884	3.8
Senegal	48,919	27,011	7,204	95,568	53.3
Serbia	6,974	3,083	736	32,308	9.5
Singapore	1,284	563	145	9,489	0.7
Slovak Republic	5,675	2,520	578	24,569	9.9
Slovenia	1,484	658	159	6,577	7.8
South Africa	25,913	11,129	2,505	79,305	6.0
Spain	38,371	16,922	4,052	179,007	5.8
Sri Lanka	5,957	2,568	601	18,863	2.6
Sudan	138,407	66,746	15,879	297,531	29.3
Sweden	9,343	4,107	925	49,231	7.2
Switzerland	3,498	1,539	379	20,286	3.0
Syrian Arab Republic	13,131	5,932	1,485	25,643	7.8
Tajikistan	6,619	2,984	720	16,419	8.5
Tanzania, United Republic	12,597	5,313	1,195	19,750	4.1
Thailand	39,392	17,309	4,010	144,813	5.6
Togo	20,323	10,373	2,590	30,340	40.6
Trinidad and Tobago	196	83	18	837	1.5
Tunisia	4,670	2,090	527	14,223	4.8
Turkey	42,948	19,160	4,779	163,265	4.2
Turkmenistan	4,236	1,901	455	21,155	4.9
Ukraine	71,096	32,196	7,400	283,722	20.7
United Arab Emirates	3,134	1,621	415	16,656	3.7
United Kingdom	47,788	20,475	4,450	230,364	4.9
United States of America	100,438	44,367	11,386	587,442	1.5
Uruguay	1,063	448	97	3,839	2.8
Uzbekistan	19,015	8,589	2,050	63,376	6.3
Venezuela	2,872	1,211	276	9,686	0.7
Vietnam	47,863	21,284	5,055	121,484	6.4
Yemen	43,190	20,522	4,932	67,727	25.8
Zambia	15,687	6,673	1,582	29,256	7.5
Zimbabwe	10,695	4,565	1,072	14,586	10.8
All-country sum/average	**7,042,494**	**3,329,772**	**800,710**	**25,365,214**	**7.9**

High, medium, and low estimates of premature mortalities in each country in 2050 are estimated by combining computer-modeled changes in $PM_{2.5}$ and ozone during 2014 due to anthropogenic sources in each country (Figure 10) with low, medium, and high relative risks and country population (Jacobson, 2010). 2014 values are then extrapolated forward to 2050 as described in the text. Human exposure is based on daily-averaged $PM_{2.5}$ exposure and 8-hr maximum ozone each day. Relative risks for long-term health impacts of $PM_{2.5}$ and ozone are as in Jacobson (2010). However, the relative risks of $PM_{2.5}$ from Pope et al. (2002) are applied to all ages as in Lepeule et al. (2012) rather than to those over 30 years old as in Pope et al. (2002). The threshold for

$PM_{2.5}$ is zero but concentrations below 8 $\mu g/m^3$ are down-weighted as in Jacobson (2010). The low ambient concentration threshold for ozone premature mortality is assumed to be 35 ppbv.

Air pollution costs are estimated by multiplying the value of statistical life (VSL) in each country by the low, medium, and high number of excess mortalities due to $PM_{2.5}$ and ozone. Estimates of the VSL are calculated as in Delucchi et al. (2015). Values for the U.S. are projected to 2050 based on GDP per capita projections (on a PPP basis) for the U.S. then scaled by country as a nonlinear function of GDP per capita in each country to the U.S. Multipliers are then used to account for morbidity and non-health impacts of air pollution.

Cost of air pollution. The total damage cost of air pollution due to conventional fuels (fossil fuel and biofuel combustion and evaporative emissions) in a country is the sum of mortality costs, morbidity costs, and non-health costs such as lost visibility and agricultural output in the country. The mortality cost equals the number of mortalities in the country multiplied by the value of statistical life (VSL). The methodology for determining the VSL by country is provided in the footnote to Table 7. The morbidity plus non-health cost per country is estimated as the mortality cost multiplied by the ratio of the value of total air-pollution damages (mortality plus morbidity plus other damages) to mortality costs alone. The result of the calculation is that the 139-country cost of air pollution in 2050 is ~$25.4 ($4.3-$69.7) trillion/yr, which corresponds to ~7.9 (1.3-21.6)% of 2050 global annual GDP on a PPP basis.

8.B. Global-Warming Damage Costs Eliminated by 100% WWS in Each Country

This section provides estimates of two kinds of climate change costs due to greenhouse gas (GHG) emissions from energy use (Table 8). GHG emissions are defined here to include emissions of carbon dioxide, other greenhouse gases, and air pollution particles that cause global warming, converted to equivalent carbon dioxide. A 100% WWS system in each country will eliminate such damages. The cost calculated is the cost of climate change impacts to the world *attributable to* emissions of GHGs from each country.

Costs of climate change include coastal flood and real estate damage costs, agricultural loss costs, energy-sector costs, water costs, health costs due to heat stress and heat stroke, influenza and malaria costs, famine costs, ocean acidification costs, increased drought and wildfire costs, severe weather costs, and increased air pollution health costs. These costs are partly offset by fewer extreme cold events and associated reductions in illnesses and mortalities and gains in agriculture in some regions. Net costs due to global-warming-relevant emissions are embodied in the social cost of carbon dioxide. The range of the 2050 social cost of carbon from recent papers is $500 (282-1,063)/metric tonne-CO_2e in 2013 dollars (Jacobson et al., 2015a). This range is used to derive the costs in Table 8.

Table 8. Percent of 2013 world CO_2 emissions by country (GCP, 2014) and low, medium, and high estimates of avoided 2050 global climate-change costs due to converting each country to 100% WWS for all purposes. All costs are in 2013 dollars.

	2013	2050 avoided global climate cost ($2013 bil./yr)		
Country	Percent of world CO_2 emissions	Low	Medium	High
Albania	0.014	4.9	2.3	1.3
Algeria	0.419	152.1	71.4	40.3
Angola	0.092	33.2	15.6	8.8
Argentina	0.577	209.3	98.3	55.4
Armenia	0.012	4.2	2.0	1.1

Australia	1.000	362.6	170.3	96.0
Austria	0.184	66.6	31.3	17.6
Azerbaijan	0.154	55.9	26.2	14.8
Bahrain	0.073	26.5	12.4	7.0
Bangladesh	0.191	69.1	32.5	18.3
Belarus	0.183	66.4	31.2	17.6
Belgium	0.290	105.3	49.4	27.9
Benin	0.016	5.8	2.7	1.5
Bolivia	0.054	19.5	9.2	5.2
Bosnia and Herzegovina	0.094	33.9	15.9	9.0
Botswana	0.015	5.5	2.6	1.5
Brazil	1.413	512.2	240.6	135.7
Brunei Darussalam	0.031	11.2	5.3	3.0
Bulgaria	0.122	44.1	20.7	11.7
Cambodia	0.014	5.2	2.4	1.4
Cameroon	0.022	8.1	3.8	2.1
Canada	1.476	534.9	251.3	141.7
Chile	0.262	95.0	44.6	25.2
China	29.265	10608.0	4983.5	2809.5
Chinese Taipei	0.776	281.2	132.1	74.5
Colombia	0.259	93.9	44.1	24.9
Congo	0.007	2.5	1.2	0.7
Congo, Dem. Republic	0.009	3.2	1.5	0.8
Costa Rica	0.023	8.4	3.9	2.2
Cote d'Ivoire	0.018	6.5	3.1	1.7
Croatia	0.060	21.8	10.3	5.8
Cuba	0.116	41.9	19.7	11.1
Cyprus	0.022	8.1	3.8	2.2
Czech Republic	0.296	107.3	50.4	28.4
Denmark	0.118	42.7	20.1	11.3
Dominican Republic	0.064	23.2	10.9	6.2
Ecuador	0.107	38.7	18.2	10.2
Egypt	0.629	228.1	107.2	60.4
El Salvador	0.018	6.7	3.1	1.8
Eritrea	0.002	0.7	0.3	0.2
Estonia	0.055	20.0	9.4	5.3
Ethiopia	0.020	7.2	3.4	1.9
Finland	0.148	53.6	25.2	14.2
France	1.009	365.7	171.8	96.8
Gabon	0.008	2.9	1.4	0.8
Georgia	0.018	6.5	3.1	1.7
Germany	2.225	806.6	378.9	213.6
Ghana	0.029	10.4	4.9	2.7
Gibraltar	0.001	0.5	0.2	0.1
Greece	0.217	78.7	37.0	20.8
Guatemala	0.033	12.0	5.6	3.2
Haiti	0.006	2.3	1.1	0.6
Honduras	0.024	8.6	4.0	2.3
Hong Kong, China	0.115	41.6	19.5	11.0
Hungary	0.121	43.9	20.6	11.6
Iceland	0.006	2.1	1.0	0.6
India	7.059	2558.7	1202.0	677.7
Indonesia	1.448	525.0	246.6	139.0
Iran, Islamic Republic	1.793	649.9	305.3	172.1
Iraq	0.360	130.4	61.3	34.5
Ireland	0.108	39.1	18.3	10.3
Israel	0.210	76.1	35.7	20.1
Italy	1.034	375.0	176.2	99.3
Jamaica	0.021	7.6	3.6	2.0

Japan	3.655	1325.0	622.5	350.9
Jordan	0.066	23.9	11.2	6.3
Kazakhstan	0.903	327.2	153.7	86.7
Kenya	0.039	14.1	6.6	3.7
Korea, Dem. People's Rep.	0.224	81.3	38.2	21.5
Korea, Republic of	1.805	654.4	307.4	173.3
Kosovo	0.025	9.0	4.2	2.4
Kuwait	0.295	107.0	50.2	28.3
Kyrgyzstan	0.019	6.9	3.2	1.8
Latvia	0.022	7.9	3.7	2.1
Lebanon	0.064	23.3	10.9	6.2
Libya	0.175	63.6	29.9	16.8
Lithuania	0.038	13.7	6.5	3.6
Luxembourg	0.031	11.4	5.3	3.0
Macedonia, Republic of	0.032	11.7	5.5	3.1
Malaysia	0.672	243.7	114.5	64.5
Malta	0.008	2.7	1.3	0.7
Mexico	1.366	495.3	232.7	131.2
Moldova, Republic of	0.014	5.1	2.4	1.4
Mongolia	0.037	13.3	6.3	3.5
Montenegro	0.008	2.8	1.3	0.7
Morocco	0.153	55.5	26.1	14.7
Mozambique	0.009	3.4	1.6	0.9
Myanmar	0.030	11.0	5.2	2.9
Namibia	0.010	3.5	1.6	0.9
Nepal	0.013	4.5	2.1	1.2
Netherlands	0.484	175.3	82.4	46.4
Netherlands Antilles	0.014	5.0	2.4	1.3
New Zealand	0.095	34.4	16.2	9.1
Nicaragua	0.013	4.9	2.3	1.3
Nigeria	0.244	88.4	41.5	23.4
Norway	0.170	61.6	28.9	16.3
Oman	0.174	62.9	29.5	16.7
Pakistan	0.482	174.9	82.2	46.3
Panama	0.028	10.0	4.7	2.6
Paraguay	0.015	5.3	2.5	1.4
Peru	0.190	68.9	32.4	18.3
Philippines	0.274	99.2	46.6	26.3
Poland	0.914	331.2	155.6	87.7
Portugal	0.152	55.2	25.9	14.6
Qatar	0.256	92.9	43.6	24.6
Romania	0.221	80.3	37.7	21.3
Russian Federation	5.315	1926.5	905.1	510.2
Saudi Arabia	1.523	552.1	259.4	146.2
Senegal	0.022	7.9	3.7	2.1
Serbia	0.111	40.4	19.0	10.7
Singapore	0.051	18.6	8.7	4.9
Slovak Republic	0.100	36.1	17.0	9.6
Slovenia	0.045	16.5	7.7	4.4
South Africa	1.314	476.1	223.7	126.1
Spain	0.704	255.0	119.8	67.5
Sri Lanka	0.043	15.5	7.3	4.1
Sudan	0.045	16.1	7.6	4.3
Sweden	0.132	48.0	22.5	12.7
Switzerland	0.118	42.8	20.1	11.3
Syrian Arab Republic	0.188	68.3	32.1	18.1
Tajikistan	0.008	3.0	1.4	0.8
Tanzania, United Republic	0.021	7.7	3.6	2.0
Thailand	0.959	347.7	163.3	92.1

Togo	0.005	1.8	0.9	0.5
Trinidad and Tobago	0.143	52.0	24.4	13.8
Tunisia	0.079	28.7	13.5	7.6
Turkey	0.954	345.7	162.4	91.6
Turkmenistan	0.158	57.4	27.0	15.2
Ukraine	0.885	320.8	150.7	85.0
United Arab Emirates	0.543	196.8	92.4	52.1
United Kingdom	1.355	491.3	230.8	130.1
United States of America	15.350	5564.1	2614.0	1473.6
Uruguay	0.020	7.1	3.3	1.9
Uzbekistan	0.302	109.5	51.5	29.0
Venezuela	0.648	234.9	110.3	62.2
Vietnam	0.496	179.9	84.5	47.7
Yemen	0.069	25.0	11.8	6.6
Zambia	0.007	2.7	1.3	0.7
Zimbabwe	0.027	9.6	4.5	2.5
World total or average	**99.747**	**36,156**	**16,986**	**9,576**

Table 8 indicates that the sum of the 139-country greenhouse gas and particle emissions may cause, in 2050, $17 (9.6-36) trillion/year in climate damage to the world. Thus, the global climate cost savings per person, averaged among these countries, to reducing all climate-relevant emissions through a 100% WWS system, is ~$2,520/person/year (in 2013 dollars) (Table 6).

9. Impacts of WWS on Jobs and Earnings in the Energy Power Sector.

This section provides estimates of job and revenue creation and loss due to implementing WWS electricity. The analysis does not include the job changes in industries outside of electric power generation, such as in the manufacture of electric vehicles, fuel cells or electricity storage because of the additional complexity required and greater uncertainty as to where those jobs will be located.

9.A. JEDI Job Creation Analysis

Changes in jobs and total earnings are estimated here first with the Jobs and Economic Development Impact (JEDI) models (NREL, 2013). These are economic input-output models with several assumptions and uncertainties (e.g. Linowes, 2012). They incorporate three levels of impacts: 1) project development and onsite labor impacts; 2) local revenue and supply chain impacts; and 3) induced impacts. Jobs and revenue are reported for two phases of development: 1) the construction period and 2) operating years.

Scenarios for WWS powered electricity generation are run for each country assuming that the WWS electricity sector is fully developed by 2050. The calculations account for only new WWS jobs associated with new WWS generator capacity as identified in Table 2 and corresponding new transmission lines. As construction jobs are temporary in nature, JEDI models report construction job creation as full-time equivalents (FTE, equal to 2,080 hours of work per year). We assume for the jobs calculation that each year from 2015 to 2050, 1/35th of the WWS infrastructure is built.

The number of jobs associated with new transmission lines assumes 80% of new lines will be 500 kV high-voltage direct current (HVDC) lines and 20% 230 kV alternating current (AC) lines. Total line length is simplistically assumed to equal five times the circular radius of a country. The transmission line JEDI model is used to calculate construction FTE jobs and annual operations jobs for the 230 kV AC lines for each country. For HVDC lines, the actual average numbers of construction FTE jobs and annual operation jobs among five proposed projects in the U.S. (Clean Line Energy Partners, 2016) are multiplied by the ratio of JEDI-model predicted number of jobs in a given country to that in the U.S. assuming 500 kV HVDC lines.

Table 9. Estimated new 35-year construction jobs, new 35-year operation jobs, 35-year construction plus operation jobs minus jobs lost, annual earnings corresponding to new construction and operation jobs, and net earnings from new construction plus operation jobs minus jobs lost (current jobs plus future jobs lost due to not growing fossil-fuel infrastructure), by country, due to converting to 100% WWS, based on the number of new generators needed of each type for annual average power and peaking/storage (Table 2). Earnings include wages, services, and supply-chain impacts.

Country	35-year construction jobs	35-year operation jobs	Job losses in fossil-fuel and nuclear energy industries	35-year net construction plus operation jobs created minus jobs lost	Annual earnings from new 40-year construction jobs (bil 2013-$/yr)	Earnings from new 40-year operation jobs (bil 2013-$/yr)	Net earnings from new construct-ion plus operation jobs minus jobs lost (bil 2013-$/yr)
Albania	6,187	6,133	6,619	5,700	0.31	0.47	0.29
Algeria	132,730	131,815	328,769	(64,224)	5.64	7.07	-4.57
Angola	31,697	17,825	274,881	(225,360)	0.95	0.69	-9.01
Argentina	117,016	115,046	171,709	60,354	6.64	8.06	2.98
Armenia	6,771	7,186	4,213	9,744	0.29	0.47	0.52
Australia	160,274	253,941	212,231	201,984	12.82	24.61	17.17
Austria	66,180	96,174	38,847	123,507	5.72	10.16	11.89
Azerbaijan	22,283	22,671	83,443	(38,488)	1.49	2.31	-4.58
Bahrain	13,458	18,340	44,380	(12,582)	0.93	1.25	-0.85
Bangladesh	128,102	98,072	205,298	20,877	2.82	3.02	-0.17
Belarus	96,367	129,650	35,672	190,345	6.58	13.52	16.55
Belgium	138,494	230,177	40,724	327,947	11.42	23.26	30.69
Benin	7,680	6,990	40,413	(25,743)	0.13	0.16	-0.63
Bolivia	17,276	12,482	49,459	(19,701)	0.50	0.47	-0.86
Bosnia and Herzegovina	11,005	10,795	9,434	12,366	0.52	0.79	0.69
Botswana	6,154	7,728	6,320	7,562	0.28	0.44	0.36
Brazil	805,170	773,637	999,444	579,364	39.37	52.11	28.67
Brunei Darussalam	5,634	7,021	29,350	(16,694)	0.79	1.23	-3.08
Bulgaria	40,203	52,452	27,158	65,498	2.61	5.21	5.37
Cambodia	13,708	8,746	46,227	(23,773)	0.31	0.27	-0.85
Cameroon	16,725	16,243	85,257	(52,289)	0.34	0.44	-1.47
Canada	292,986	463,322	580,544	175,765	23.40	44.28	13.67
Chile	87,315	119,086	118,784	87,617	5.42	10.09	6.17
China	6,695,881	6,492,101	4,175,098	9,012,884	425.66	613.69	681.99
Chinese Taipei	257,718	165,443	130,932	292,229	39.41	36.13	51.51
Colombia	68,993	78,200	161,054	(13,861)	2.82	4.05	-1.33
Congo	4,026	3,331	57,148	(49,791)	0.11	0.12	-1.84
Congo, Dem. Republic	69,678	69,145	510,596	(371,773)	0.87	1.17	-6.50
Costa Rica	8,373	5,151	10,603	2,922	0.36	0.28	0.09
Cote d'Ivoire	20,346	19,054	127,848	(88,449)	0.43	0.53	-2.56
Croatia	21,457	31,025	15,622	36,860	1.61	3.54	3.43
Cuba	20,219	19,151	19,483	19,887	1.08	1.27	1.11
Cyprus	5,366	6,247	2,873	8,740	0.52	0.92	1.06

Czech Republic	74,716	81,158	37,396	118,479	4.90	6.65	8.60
Denmark	18,552	31,663	32,560	17,654	1.58	3.29	1.53
Dominican Republic	14,202	7,540	14,363	7,380	0.58	0.39	0.27
Ecuador	24,209	19,155	66,306	(22,942)	0.91	0.92	-1.29
Egypt	200,576	174,629	341,151	34,053	7.28	8.10	0.47
El Salvador	6,218	3,516	10,329	(595)	0.20	0.15	-0.07
Eritrea	2,006	1,172	13,576	(10,397)	0.03	0.02	-0.23
Estonia	4,450	6,245	7,370	3,325	0.27	0.48	0.21
Ethiopia	89,505	60,372	633,140	(483,263)	1.41	1.27	-10.57
Finland	47,316	82,222	38,261	91,277	3.75	8.02	8.15
France	320,178	329,457	173,156	476,479	24.80	31.45	40.44
Gabon	7,377	10,216	36,164	(18,571)	0.37	0.64	-1.23
Georgia	8,663	9,003	8,403	9,263	0.35	0.57	0.44
Germany	786,658	1,203,675	229,418	1,760,914	67.56	126.27	170.58
Ghana	23,965	23,005	76,632	(29,661)	0.56	0.70	-1.00
Gibraltar	2,884	3,179	1,651	4,412	0.28	0.36	0.46
Greece	32,152	29,511	26,081	35,582	1.91	2.21	2.25
Guatemala	21,538	11,805	45,431	(12,089)	0.65	0.46	-0.64
Haiti	5,903	3,670	35,591	(26,019)	0.10	0.08	-0.60
Honduras	10,167	7,760	22,133	(4,206)	0.25	0.25	-0.19
Hong Kong, China	63,420	88,748	28,433	123,735	6.94	12.43	15.81
Hungary	57,634	61,612	24,034	95,212	3.35	4.52	6.15
Iceland	1,277	3,125	3,770	632	0.11	0.32	0.07
India	1,905,892	1,698,048	2,508,442	1,095,497	66.46	85.26	34.89
Indonesia	542,376	500,691	812,101	230,966	21.18	26.76	5.74
Iran, Islamic Republic	428,126	505,881	758,697	175,310	16.35	20.67	6.19
Iraq	56,028	57,091	333,803	(220,684)	2.00	2.20	-8.63
Ireland	11,375	16,049	10,844	16,579	1.03	1.76	1.64
Israel	35,321	37,484	18,138	54,667	2.44	3.22	4.20
Italy	367,618	510,080	133,351	744,347	26.37	45.39	60.28
Jamaica	5,666	4,756	6,159	4,263	0.19	0.21	0.14
Japan	609,972	775,535	216,731	1,168,776	42.28	59.71	85.73
Jordan	11,438	11,082	16,051	6,468	0.37	0.39	0.21
Kazakhstan	133,237	186,358	198,466	121,129	10.97	23.28	9.98
Kenya	33,780	23,761	184,209	(126,668)	0.68	0.64	-3.56
Korea, Dem. People's Rep.	60,011	89,493	80,135	69,369	1.01	2.02	1.35
Korea, Republic of	554,236	696,549	218,433	1,032,352	40.61	61.54	84.24
Kosovo	4,499	3,927	6,163	2,263	0.15	0.17	0.07
Kuwait	41,772	61,753	230,457	(126,932)	4.21	5.81	-11.74
Kyrgyzstan	12,599	11,926	11,264	13,261	0.34	0.50	0.42
Latvia	13,249	21,899	14,758	20,390	1.07	2.69	1.99
Lebanon	12,090	15,144	12,802	14,433	0.48	0.64	0.59
Libya	28,804	36,810	189,158	(123,544)	1.29	2.07	-7.08
Lithuania	15,343	22,630	12,922	25,050	1.36	3.03	2.69
Luxembourg	10,474	13,682	3,153	21,003	1.52	2.32	3.31
Macedonia, Republic of	6,642	6,964	4,597	9,009	0.37	0.59	0.60
Malaysia	201,726	249,037	242,179	208,584	12.97	21.29	14.59
Malta	4,416	7,730	2,271	9,875	0.44	1.16	1.27
Mexico	357,982	276,549	681,535	(47,004)	18.55	19.76	-7.89
Moldova, Republic of	7,506	7,904	6,329	9,081	0.25	0.40	0.35
Mongolia	14,981	18,296	20,772	12,506	0.63	1.04	0.53
Montenegro	1,862	2,302	2,655	1,509	0.11	0.21	0.10
Morocco	50,417	47,700	50,580	47,538	1.52	1.86	1.58
Mozambique	20,054	17,820	235,785	(197,911)	0.29	0.34	-3.77
Myanmar	47,164	44,916	132,282	(40,202)	1.19	1.57	-1.80
Namibia	6,297	8,612	40,507	(25,597)	0.22	0.38	-1.19
Nepal	29,159	25,110	89,848	(35,579)	0.57	0.69	-1.18
Netherlands	130,655	202,498	104,308	228,844	11.54	21.80	22.27
Netherlands Antilles	5,867	6,931	4,992	7,806	0.36	0.53	0.51

New Zealand	17,908	22,400	28,140	12,168	1.47	2.41	0.95
Nicaragua	4,883	3,044	11,775	(3,848)	0.13	0.11	-0.18
Nigeria	297,339	267,408	1,055,358	(490,611)	8.69	10.83	-23.01
Norway	6,846	20,905	167,568	(139,817)	0.77	2.81	-18.70
Oman	68,007	137,045	126,186	78,866	4.45	8.91	5.15
Pakistan	291,110	239,989	415,745	115,354	7.75	8.89	1.82
Panama	12,875	15,229	11,295	16,809	0.68	1.00	0.96
Paraguay	6,315	6,187	39,111	(26,609)	0.21	0.26	-1.06
Peru	43,738	34,599	70,724	7,613	1.69	1.70	0.01
Philippines	122,836	52,732	137,230	38,338	3.89	2.31	0.66
Poland	106,619	90,548	83,788	113,379	6.25	6.69	6.96
Portugal	17,745	16,422	25,104	9,062	1.10	1.27	0.49
Qatar	51,961	74,198	233,790	(107,631)	8.21	10.22	-13.89
Romania	67,470	87,289	68,808	85,952	4.81	9.49	7.14
Russian Federation	775,287	1,270,480	1,284,150	761,617	53.88	110.92	55.14
Saudi Arabia	203,791	291,192	850,553	(355,569)	15.34	21.35	-25.77
Senegal	8,927	6,829	40,397	(24,641)	0.16	0.17	-0.63
Serbia	32,840	39,094	27,110	44,825	1.85	3.38	3.06
Singapore	148,437	184,238	63,317	269,358	22.01	34.12	44.97
Slovak Republic	23,182	27,182	13,929	36,435	1.44	2.12	2.52
Slovenia	10,412	19,428	7,819	22,021	0.67	1.57	1.64
South Africa	261,253	341,308	364,605	237,955	10.62	17.58	10.80
Spain	146,725	153,638	106,276	194,087	10.36	13.47	14.90
Sri Lanka	29,656	22,127	49,676	2,107	1.16	1.18	-0.22
Sudan	32,384	20,603	126,111	(73,125)	0.75	0.63	-2.40
Sweden	24,468	47,846	61,730	10,584	2.12	5.06	0.89
Switzerland	43,674	69,983	24,050	89,607	4.46	8.59	10.21
Syrian Arab Republic	23,685	26,787	73,418	(22,946)	0.62	0.79	-0.71
Tajikistan	6,028	4,438	8,429	2,037	0.15	0.17	0.06
Tanzania, United Republic	53,197	49,937	239,353	(136,218)	1.02	1.28	-3.77
Thailand	343,836	379,740	344,050	379,526	16.05	24.02	19.42
Togo	5,590	5,203	48,900	(38,107)	0.09	0.11	-0.82
Trinidad and Tobago	14,818	24,200	58,525	(19,508)	1.01	2.00	-1.80
Tunisia	31,825	34,375	45,219	20,982	1.22	1.67	0.81
Turkey	183,724	192,954	86,934	289,744	9.34	12.51	16.51
Turkmenistan	81,962	106,809	97,413	91,358	5.06	10.10	6.04
Ukraine	225,210	266,730	141,324	350,616	9.90	18.09	19.13
United Arab Emirates	247,340	364,159	299,639	311,859	21.86	30.62	27.20
United Kingdom	148,349	209,933	197,164	161,118	11.57	20.17	13.28
United States of America	2,254,009	2,771,668	2,086,077	2,939,600	227.25	342.64	319.25
Uruguay	7,644	8,903	12,523	4,023	0.40	0.58	0.19
Uzbekistan	166,410	173,563	131,200	208,772	5.79	9.34	8.25
Venezuela	108,932	140,706	303,086	(53,448)	5.18	8.39	-4.23
Vietnam	167,279	153,198	298,885	21,592	4.78	6.07	-0.28
Yemen	19,712	14,400	72,518	(38,406)	0.39	0.33	-0.93
Zambia	20,105	17,405	93,112	(55,602)	0.46	0.52	-1.72
Zimbabwe	21,438	20,643	129,473	(87,392)	0.36	0.46	-2.00
World total or average	**23,985,454**	**26,497,510**	**28,412,244**	**22,070,720**	**1519.11**	**2280.44**	**1870.41**

Table 9 indicates that 100% conversion to WWS across 139 countries may create ~24.0 million new 35-year construction jobs and ~26.5 million new 35-year operation and maintenance jobs for the WWS generators and transmission proposed. These employment numbers do not include all external jobs created in areas such as research and development, storage development, and local economy improvement.

Table 10 provides a summary among 139 countries of job loss in the oil, gas, coal, nuclear, bioenergy industries. Job loss is calculated as the product of jobs per unit energy in each employment category and total energy use. Total energy use is the product of energy use in 2012 from IEA World Energy Balances, by country, and the ratio of energy use in the target year to energy use in 2012 (from IEO projections by region, extrapolated past 2040, and mapped to individual countries). Jobs per unit energy are calculated as the product of jobs per unit energy unit in the U.S. in 2012, the fraction of conventional-fuel jobs lost due to converting to WWS (Table 10), a multiplier for jobs associated with the jobs lost but not counted elsewhere, and country-specific adjustment factors accounting for the relationship between jobs per unit energy and GDP per capita and total energy use.

The fraction of fossil-fuel jobs lost in each job sector (Table 10), accounts for the fact that some non-energy uses of fossil fuels will be retained (e.g., the use of some petroleum products will be used as lubricants, asphalt, petrochemical feedstock, and petroleum coke) or that transportation categories include transportation of goods other than fossil fuels.

Job losses include construction jobs lost from not building future fossil, nuclear, and bio-power plants because WWS plants are built instead. Job losses from not replacing existing conventional plants are not treated to be consistent with the fact that jobs created by replacing WWS plants with other WWS plants are not treated.

The shift to WWS is estimated to result in the loss of ~28.4 million jobs in the current fossil-fuel, biofuel, and nuclear industries in the 139 countries. The job loss represents ~1% of the total workforce in the 139 countries.

Table 10. Estimated 139-country job losses due to eliminating energy generation and use from the fossil fuel and nuclear sectors. Also shown is the percent of total jobs in the sector that are lost. Not all fossil-fuel jobs are lost due to non-energy uses of petroleum, such as lubricants, asphalt, petrochemical feedstock, and petroleum coke. For transportation sectors, the jobs lost are those due to transporting fossil fuels; the jobs not lost are those for transporting other goods.

Energy sector	**Jobs lost in sector**	**Percent of jobs in sector that are lost**
Oil and gas extraction	2,272,000	87
Coal mining	987,000	97
Uranium mining	110,500	100
Support for oil and gas	3,412,000	87
Oil and gas pipeline construction	1,543,000	87
Mining & oil/gas machinery	1,101,000	87
Petroleum refining	561,000	93
Asphalt paving and roofing materials	0	0
Gas stations with stores	1,544,000	30
Other gas stations	361,000	50
Fossil electric power generation utilities	884,000	100
Fossil electric power generation non-utilities	154,000	100

Nuclear and other power generation	1,038,000	100
Natural gas distribution	1,033,000	100
Auto oil change shops/other repair	51,900	10
Rail transportation of fossil fuels	649,000	52
Water transportation of fossil fuels	211,600	23
Truck transportation of fossil fuels	758,700	8
Bioenergy except electricity	7,089,000	100
Total current jobs lost	**23,762,000**	
[h]**Jobs lost from not growing fossil fuels**	**4,650,000**	
All jobs lost	**28,412,000**	
[i]Total labor force	2.87 billion	
Jobs lost as percent of labor force	**0.99%**	

[a]See Delucchi et al. (2015) for detailed calculations and referencing.
[b]Jobs lost from not growing fossil fuels are additional construction and operation jobs that would have accrued by 2050 if BAU instead of WWS continued.
[c]The total labor force in each country is obtained from World Bank (2015b).

Subtracting the number of jobs lost across the 139 countries from the number of jobs created gives a net of ~22.1 million 35-year jobs created due to WWS. Although all countries together are expected to gain jobs, some countries, particularly those that currently extract significant fossil fuels (e.g., Kuwait, Iraq, Nigeria, Qatar, Saudi Arabia, Sudan, Venezuela, Yemen) may experience net job loss in the energy production sector. However, such job loss in many of those countries can potentially be made up in the manufacture and service of storage technologies, hydrogen technologies, electric vehicles, electric heating and cooling appliances, and industrial heating equipment, although such job creation numbers were not determined here.

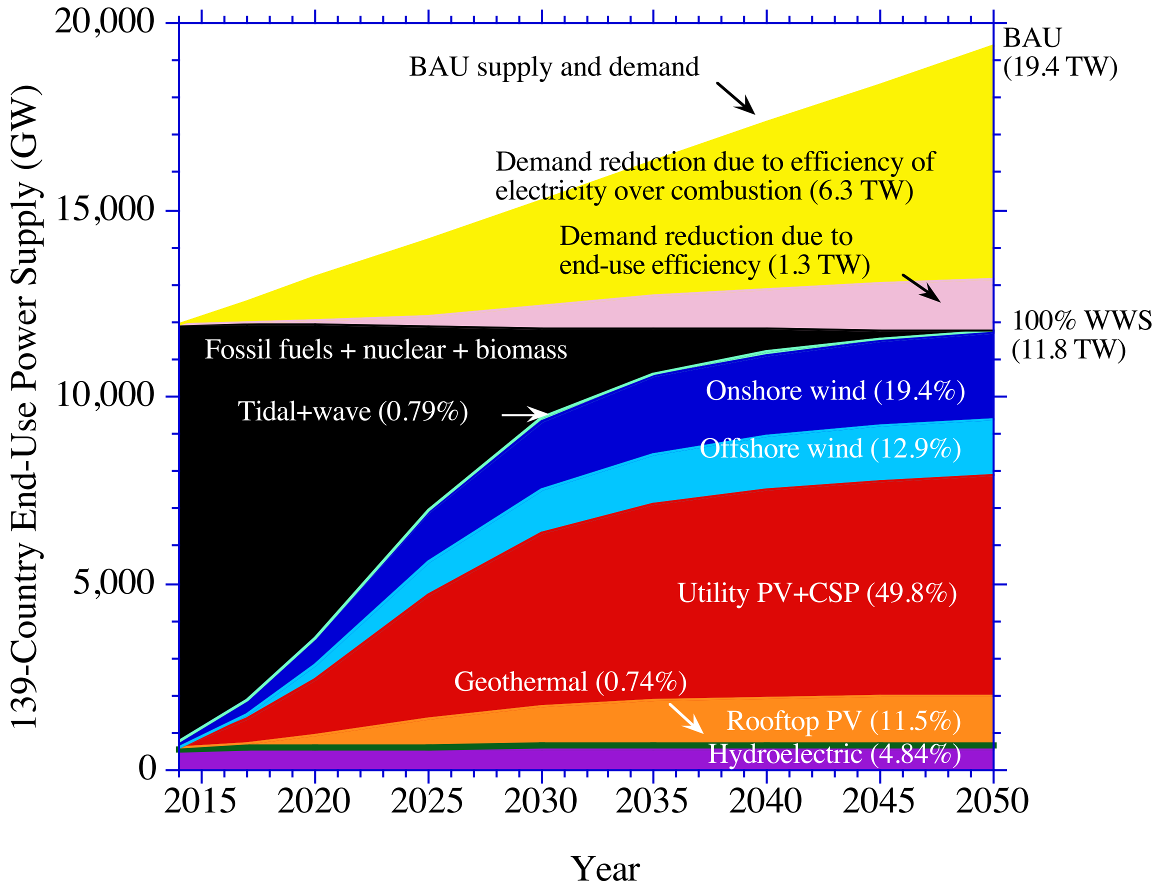
The direct and indirect earnings from producing WWS electricity amount to ~$1.52 trillion/year during the construction stage and ~$2.28 trillion/yr during the operation stage. The annual earnings lost from the fossil-fuel industries total ~$1.93 trillion/yr giving a net gain in annual earnings of ~$1.87 trillion/yr.

10. Timeline for Implementing the Roadmaps

Figure 11 shows the mean proposed timeline for the complete transformation of the energy infrastructures of the 139 countries considered here. The timeline assumes 100% WWS by 2050, with 80-85% WWS by 2030. To meet this timeline, rapid transitions are needed in each technology sector. Whereas, much new infrastructure can be installed upon retirement of existing infrastructure or devices, other transitions will require aggressive policies (Section 11) to meet the timeline. Below is a list of proposed transformation timelines for individual sectors.

Figure 11. Mean change in 139-country end-use power demand for all purposes (electricity, transportation, heating/cooling, industry, agriculture/fishing/forestry, and other) and its supply by conventional fuels and WWS generators over time based on the country roadmaps proposed here. Total power demand decreases upon conversion to WWS due to the efficiency of electricity over combustion and end-use energy efficiency measures. The percentages next to each WWS source are the final (2050) estimated percent supply of end-use

power by the source. The 100% demarcation in 2050 indicates that 100% of all-purpose power is provided by WWS technologies by 2050, and the power demand by that time has decreased.



Development of super grids and smart grids. As soon as possible, countries should develop plans for long-term power-transmission-and-distribution systems to provide "smart" management of energy demand and supply at all scales, from local to international (e.g., Smith et al., 2013; Blarke and Jenkins, 2013; Elliott, 2013).

Power plants: by 2020, no more construction of new coal, nuclear, natural gas, or biomass fired power plants; all new power plants built are WWS. This is feasible because few power plants are built annually, and most WWS electric power generator technologies are already cost competitive.

Heating, drying, and cooking in the residential and commercial sectors: by 2020, all new devices and machines are powered by electricity. This is feasible because the electric versions of these products are already available, and all sectors can use electricity without adaptation (the devices can be plugged in or installed).

Large-scale waterborne freight transport: by 2020-2025, all new ships are electrified and/or use electrolytic hydrogen, all new port operations are electrified, and port retroelectrification is well underway. This should be feasible for relatively large ships and ports because large ports are centralized and few ships are built each year. Policies may be needed to incentivize the early retirement of ships that do not naturally retire before 2050.

Rail and bus transport: by 2025, all new trains and buses are electrified. This requires changing the supporting energy-delivery infrastructure and the manufacture method of transportation equipment. However, relatively few producers of buses and trains exist, and the supporting energy infrastructure is concentrated in cities.

Off-road transport, small-scale marine: by 2025 to 2030, all new production is electrified.

Heavy-duty truck transport: by 2025 to 2030, all new heavy-duty trucks and buses are electrified or use electrolytic hydrogen. It may take 10-15 years for manufacturers to retool and for enough of the supporting energy-delivery infrastructure to be put in place.

Light-duty on-road transport: by 2025-2030, all new light-duty onroad vehicles are electrified. Manufacturers need time to retool, but more importantly, several years are needed to get the energy-delivery infrastructure in place for a 100% WWS transportation fleet..

Short-haul aircraft: by 2035, all new small, short-range aircraft are battery- or electrolytic-hydrogen powered. Changing the design and manufacture of airplanes and the design and operation of airports are the main limiting factors to a more rapid transition.

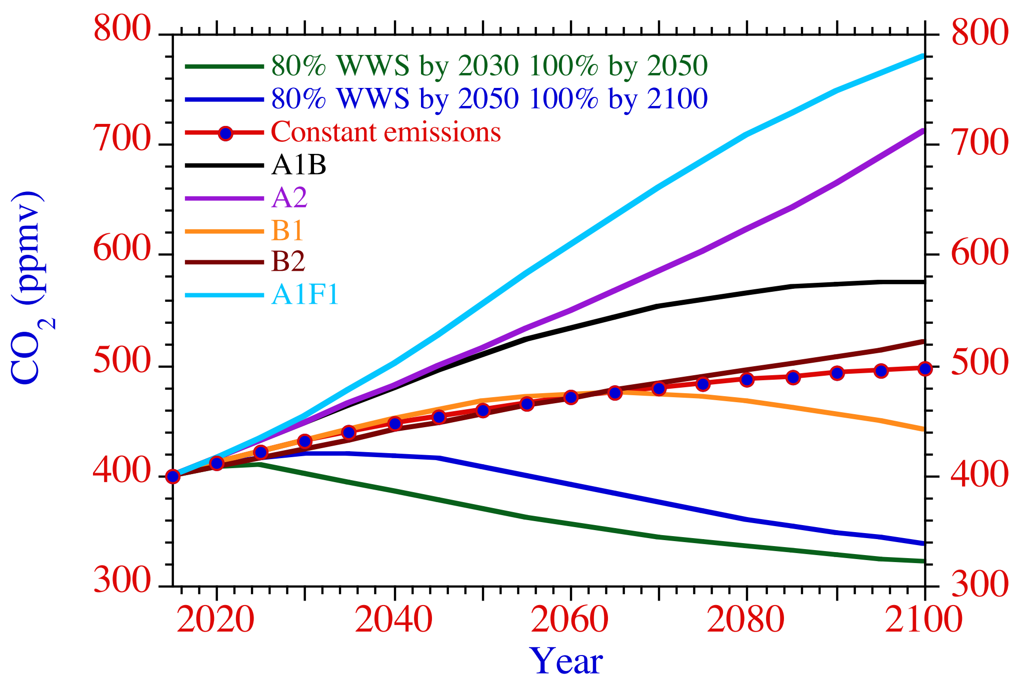
Long-haul aircraft: by 2040, all remaining new aircraft use electrolytic cryogenic hydrogen (Jacobson and Delucchi, 2011, Section A.2.7) with electricity power for idling, taxiing, and internal power. The limiting factors to a faster transition are the time and social changes required to redesign aircraft and airports.

During the transition, conventional fuels and existing WWS technologies are needed to produce the remaining WWS infrastructure. However, much of the conventional energy would be used in any case to produce conventional power plants and automobiles if the plans proposed here were not implemented. Further, as the fraction of WWS energy increases, conventional energy generation will decrease, ultimately to zero, at which point all new WWS devices will be produced with existing WWS. In sum, the creation of WWS infrastructure may result in a temporary increase in emissions before they are ultimately reduced to zero.

Figure 12 illustrates the impact on global carbon dioxide levels of the aggressive goals proposed here (80% WWS by 2030 and 100% by 2050) as well as of a less aggressive scenario that provides 80% WWS by 2050 and 100% by 2100. Both scenarios reduce CO_2 levels below those today. The 100% by 2050 scenario reduces CO_2 to 370 ppmv by 2050, a level last seen around 2000, and to 350 ppmv by 2065. By 2100, CO_2 would be reduced to 321 ppmv, a level last seen around 1966. Merely maintaining a constant emission rate, which is a conservative assumption because emissions are increasing rather than staying constant today, results in CO_2 increasing to 500 ppmv by 2100. All IPCC (2000) emission scenarios similarly result in CO_2 levels much higher than in WWS scenarios through 2100.

Further, the WWS plans proposed here will eliminate energy-related black carbon, the second-leading cause of global warming after carbon dioxide, and energy-related methane, the third-leading cause, as well as tropospheric ozone precursors, carbon monoxide, and nitrous oxide from energy. As such the aggressive worldwide conversion to WWS proposed here will avoid exploding levels of CO_2 and other global warming contaminants, potentially avoiding catastrophic climate change.

Figure 12. Change in world CO_2 mixing ratio (ppmv) resulting from five Intergovernmental Panel on Climate Change (IPCC) scenarios (IPCC, 2000), a case assuming constant current emissions, in a 100% by 2050 WWS case from Figure 11, and in a less-aggressive 80% by 2050 and 100% by 2100 case.



The curves are derived from Equation 3.22 of Jacobson (2012). They assume a 2015 mixing ratio of CO_2 of 400 ppmv, a pre-industrial CO_2 mixing ratio of 275 ppmv, and a data-constrained CO_2 lifetime of 50 years (Jacobson, 2012). In the WWS cases, they assume an initial fossil-fuel CO_2 emission rate of 9860 Tg-C/year (Le Quere et al., 2015), reduced by 80% by 2030 and 100% by 2050 in one case and 80% by 2050 and 100% by 2100 in the other. In both cases, and in the constant-emission case, a constant landuse-change CO_2 emission rate of 800 Tg-C/year (Le Quere et al., 2015) was used. The IPCC scenarios used emissions for fossil fuels and landuse change directly from IPCC (2000). 2184.82 Tg-C = 1 ppmv.

11. Recommended First Steps

The policy pathways necessary to transform the 139 countries treated here to 100% WWS will differ by country, depending largely on the willingness of the government and people in each country to affect rapid change. This study does not advocate specific policy measures for any country. Instead, it provides a set of policy options that each country can consider. The list is by no means complete. Within each section, the policy options are listed roughly in order of proposed priority.

12.1. Energy Efficiency Measures

- Expand clean, renewable energy standards and energy efficiency standards.

- Incentivize conversion from natural gas water and air heaters to electric heat pumps (air and ground-source) and rooftop solar thermal hot water pre-heaters.

- Promote, though municipal financing, incentives, and rebates, energy efficiency measures in buildings and other infrastructure. Efficiency measures include, but are not limited to, using LED lighting; evaporative cooling; ductless heating and air conditioning; energy-storing materials in walls and floors to modulate temperature changes, water-cooled heat exchanging; night ventilation cooling; combined space and water heating; improved data center design; improved air flow management; advanced lighting controls; variable refrigerant flow; improved wall, floor, ceiling, and pipe insulation; double- and triple-paned windows; and passive solar heating. Additional measures include sealing windows, doors, and fireplaces; and monitoring building energy use and performing energy audits to find energy waste.

- Revise building codes to incorporate "green building standards" based on best practices for building design, construction, and energy use.

- Incentivize landlord investment in energy efficiency. Allow owners of multi-family buildings to take a property tax exemption for energy efficiency improvements in their buildings that provide benefits to their tenants.

- Create energy performance rating systems with minimum performance requirements to assess energy efficiency levels and pinpoint areas of improvement.

- Create a green building tax credit program for the corporate sector.

12.2. Energy Supply Measures

- Increase Renewable Portfolio Standards (RPSs).

- Extend or create state WWS production tax credits.

- Streamline the permit approval process for large-scale WWS power generators and high-capacity transmission lines. Work with local and regional governments to manage zoning and permitting issues within existing planning efforts or pre-approve sites to reduce the cost and uncertainty of projects and expedite their physical build-out.

- Streamline the small-scale solar and wind installation permitting process. Create common codes, fee structures, and filing procedures across a country.

- Lock in fossil fuel and nuclear power plants to retire under enforceable commitments. Implement taxes on emissions by current utilities to encourage their phase-out.

- Incentivize clean-energy backup emergency power systems rather than diesel/gasoline generators at both the household and community levels.

- Incentivize home or community energy storage (through garage electric battery systems, for example) that accompanies rooftop solar to mitigate problems associated with grid power losses.

12.3. Utility Planning and Incentive Structures

- Incentivize community seasonal heat storage underground using the Drake Landing solar community as an example.

- Incentive the development of utility-scale grid electric power storage, such as in CSP, pumped hydropower, and more efficient hydropower.

- Require utilities to use demand response grid management to reduce the need for short-term energy backup on the grid.

- Incentivize the use of excess WWS electricity to produce hydrogen to help manage the grid.

- Develop programs to use EV batteries, after the end of their useful life in vehicles, for local, short-term storage and balancing.

- Implement virtual net metering (VNM) for small-scale energy systems.

12.4. Transportation

- Promote more public transit by increasing its availability and providing compensation to commuters for not purchasing parking passes.

- Increase safe biking and walking infrastructure, such as dedicated bike lanes, sidewalks, crosswalks, timed walk signals, etc.

- Adopt legislation mandating BEVs for short- and medium distance government transportation and using incentives and rebates to encourage the transition of commercial and personal vehicles to BEVS.

- Use incentives or mandates to stimulate the growth of fleets of electric and/or hydrogen fuel cell/electric hybrid buses starting with a few and gradually growing the fleets. Also incentivize electric and hydrogen fuel cell ferries, riverboats, and other local shipping.

- Adopt zero-emission standards for all new on-road and off-road vehicles, with the percentage of new production required to be zero-emission increasing to 100% by 2030 at the latest.

- Ease the permitting process for installing electric charging stations in public parking lots, hotels, suburban metro stations, on streets, and in residential and commercial garages.

- Set up time-of-use electricity rates to encourage charging at night.

- Incentivize the electrification of freight rail and shift freight from trucks to rail.

12.5. Industrial Processes

- Provide financial incentives for industry to convert to electricity and electrolytic hydrogen for high temperature and manufacturing processes.

- Provide financial incentives to encourage industries to use WWS electric power generation for on-site electric power (private) generation.

12. Summary

Roadmaps are presented for converting the energy systems for all purposes (electricity, transportation, heating/cooling, industry, and agriculture/forestry/fishing) of 139 countries into clean and sustainable ones powered by wind, water, and sunlight (WWS).

For each country, the study estimates 2050 BAU power demand from current data, converts the supply for each load sector to WWS supply, and proposes a mix of WWS generators within each the country that can match projected 2050 all-sector power demand. The conversion from BAU combustion to WWS electricity for all purposes is calculated to reduce 139-country-averaged end-use load by ~39.2%, with ~82% of this due to electrification and eliminating the need for mining, transport, and refining of conventional fuels, and the rest due to end-use energy efficiency improvements.

Remaining all-purpose annually-averaged end-use 2050 load over the 139 countries is proposed to be met with ~1.17 million new onshore 5-MW wind turbines (providing 19.4% of 139-country power for all purposes), 762,000 off-shore 5-MW wind turbines (12.9%), 496,900 50-MW utility-scale solar-PV power plants (42.2%), 15,400 100-MW utility-scale CSP power plants with storage (7.7%), 653 million 5-kW residential rooftop PV systems (5.6%), 35.3 million 100-kW commercial/government rooftop systems (6.0%), 840 100-MW geothermal plants (0.74%), 496,000 0.75-MW wave devices (0.72%), 32,100 1-MW tidal turbines (0.07%), and 0 new hydropower plants. The capacity factor of existing hydropower plants will increase slightly so that hydropower supplies 4.8% of all-purpose power. Another estimated 9,300 100-MW CSP plants with storage and 99,400 50-MW solar thermal collectors for heat generation and storage will be needed to help stabilize the grid. This is just one possible mix of generators.

The additional footprint on land for WWS devices is equivalent to about 0.29% of the 139-country land area, mostly for utility scale PV. This does not account for land gained from eliminating the current energy infrastructure. An additional on-land spacing area of about 0.65% for the 139 countries is required for onshore wind, but this area can be used for multiple purposes, such as open space, agricultural land, or grazing land.

The 2013 LCOE for hydropower, onshore wind, utility-scale solar, and solar thermal for heat is already similar to or less than the LCOE for natural gas combined-cycle power plants. Rooftop PV, offshore wind, tidal, and wave presently have higher LCOEs. However, by 2050 the LCOE for all WWS technologies is expected to drop, most significantly for offshore wind, tidal, wave, rooftop PV, CSP, and utility PV, whereas conventional fuel costs are expected to rise.

The 139-country roadmaps are anticipated to create 24.0 million 35-year construction jobs and 26.5 million 35-year operation jobs for the energy facilities alone, the combination of which would outweigh by ~22.1 million the 28.4 million jobs lost in the conventional energy sector.

The 139-country roadmaps will eliminate ~4.6 (1.3-8.0) million premature air pollution mortalities per year today and 3.3 (0.8-7.0) million/yr in 2050, avoiding ~$25.4 ($4.3-$69.7) trillion/year in 2050 air-pollution damage costs (2013 dollars), equivalent to ~7.9 (1.3-21.6) percent of the 2050 139-country GDP.

Converting will further eliminate ~$17 (9.6-36) trillion/year in 2050 global warming costs (2013 dollars) due to 139-country greenhouse-gas and particle emissions.

These plans will result in the average person in 2050 saving $170/year in fuel costs compared with conventional fuels, ~2,880/person/year in air-pollution-damage cost and ~$1,930/person/year in climate costs (2013 dollars).

Many uncertainties in the analysis here are captured in broad ranges of energy, health, and climate costs given. However, these ranges may miss costs due to limits on supplies caused by wars or political/social opposition to the roadmaps. As such, the estimates should be reviewed periodically.

The timeline for conversion is proposed as follows: 80% of all energy to be WWS by 2030 and 100% by 2050. As of the end of 2014, three countries -- Norway (67%), Paraguay (54%), and Iceland (39%) – have installed more than 35% of their projected all-purpose 2050 needed nameplate capacity of WWS energy. The world average conversion to date is 3.8%.

The major benefits of a conversion are the near-elimination of air pollution morbidity and mortality and global warming, net job creation, energy-price stability, reduced international conflict over energy because each country will largely be energy independent, increased accessed to distributed energy and reduced energy poverty to the 4 billion people worldwide who currently collect their own energy and burn it, and reduced risks of large-scale system disruptions because much of the world power supply will be decentralized. Finally, the aggressive worldwide conversion to WWS proposed here will avoid exploding levels of CO_2 and catastrophic climate change.

The study finds that the conversion to WWS is technically and economically feasible. The main barriers are still social and political.

Acknowledgments

We would like to thank The Solutions Project for partial funding of three students. The spreadsheets for this paper can be found in Delucchi et al. (2015).

References

Anenberg, S.C., D. Shindell, M. Amann, G. Faluvegi, et al., 2012. Global air quality and health co-benefits of mitigating near-term climate change through methane and black carbon emission controls, *Environmental Health Perspectives, 120*, 831-839.

Arent, D., P. Sullivan, D. Heimiller, A. Lopez, K. Eurek, J. Badger, H.E. Jorgensen, and M. Kelly, 2015, 2012, Improved offshore wind resource assessment in global climate stabilization scenarios, NREL/TP-6A20-55049, http://www.nrel.gov/docs/fy13osti/55049.pdf, Accessed June 11, 2015.

Bertani, R., 2015. Geothermal Power Generation in the World 2010-2014 Update Report, World Geothermal Congress 2015 Conference Proceedings, Melbourne, Australia, 19-25 April 2015.

Beyond Zero Emissions, *Zero Carbon Australia Stationary Energy Plan*, Melbourne Energy Institute, University of Melbourne, July, 2010. http://media.bze.org.au/ZCA2020_Stationary_Energy_Report_v1.pdf, Accessed May 2, 2015.

Blarke, M. B., and B. M. Jenkins, 2013. SuperGrid or SmartGrid: Competing Strategies for large-scale integration of intermittent renewables?, Energy Policy 58: 381-390.

Buonocore, J.J., P. Luckow, G. Norris, J.D. Spengler, B. Biewald, J. Fisher, and J.I. Levy, Health and climate benefits of different energy efficiency and renewable energy choices, *Nat. Clim. Change*, doe:10.1039/NCLIMATE2771, 2015.

Clean Line Energy Partners, 2015, Projects, http://www.cleanlineenergy.com/projects, Accessed Sept. 20, 2015.

Connolly, D., and B.V. Mathiesen, 2014, A technical and economic analysis of one potential pathway to a 100% renewable energy system, Intl. J. Sustainable Energy Planning & Management, 1, 7-28.

CSP World, 2015. CSP world map. http://www.cspworld.org/cspworldmap. Accessed July 22, 2015.

Delucchi, M.A., Jacobson, M.Z., 2011. Providing all global energy with wind, water, and solar power, Part II: Reliability, System and Transmission Costs, and Policies. Energy Policy, 39, 1170-1190, doi:10.1016/j.enpol.2010.11.045.

Delucchi, M.A., M.Z. Jacobson, Z.A.F. Bauer, S. Goodman, and W. Chapman, 2015. Spreadsheets for 139-country 100% wind, water, and solar roadmaps, http://web.stanford.edu/group/efmh/jacobson/Articles/I/WWS-50-USState-plans.html. Accessed November 18, 2015.

DOE (Department of Energy, U.S.), 2012. An Assessment of Energy Potential at Non-Powered Dams in the United states, http://nhaap.ornl.gov/system/files/NHAAP_NPD_FY11_Final_Report.pdf. Accessed December 17, 2012.

Dulac, J., 2013. Global Land Transport Infrastructure Requirements, *International Energy Agency*, https://www.iea.org/publications/freepublications/publication/TransportInfrastructureInsights_FINAL_WEB.pdf, Accessed September 9, 2015.

Dvorak, **M.,** C.L. Archer, and M.Z. Jacobson, 2010. California offshore wind energy potential, *Renewable Energy*, 35, 1244-1254, doi:10.1016/j.renene.2009.11.022.

ECF (European Climate Foundation), 2010, *Roadmap 2050: A Practical Guide to a Prosperous, Low-Carbon Europe*, http://www.roadmap2050.eu/project/roadmap-2050, Accessed May 2, 2015.

EIA (Energy Information Agency), 2015. International Energy Outlook, 2014, http://www.eia.gov/forecasts/ieo/, Accessed November 17, 2015.

Eiffert, P., 2003. Non-technical barriers to the commercialization of PV power systems in the built environment, NREL/TP-550-31976, http://www.nrel.gov/docs/fy03osti/31976.pdf, Accessed September 8, 2015.

Elliott, D., 2013. Emergence of European supergrids – Essay on strategy issues, Energy Strategy Reviews 1: 171-173.
ELTE/EENA (ELTE University sustainable energy research group/Environmental education network association), 2014, Hungarian sustainable energy vision, http://inforse.dk/europe/VisionHU.htm, Accessed May 2, 2015.
Entranze Data Tool, 2015. *.Intelligent Energy Europe Program, European Union*. http://www.entranze.enerdata.eu/, Accessed September 8, 2015.
EPIA (European Photovoltaic Industry Association) 2014. Global Market Outlook for Photovoltaics 2014-2020, http://www.epia.org/fileadmin/user_upload/Publications/44_epia_gmo_report_ver_17_mr.pdf, Accessed 27 July 2015.
EREC (European Renewable Energy Council), 2010, *RE-Thinking 2050: A 100% Renewable Energy Vision for the European Union*, http://www.erec.org/fileadmin/erec_docs/Documents/Publications/ReThinking2050_full%20version_final.pdf, Accessed May 2, 2015.
GCP (Global Carbon Project), Global Carbon Budget 2014 spreadsheet, Territorial Emissions, http://www.globalcarbonproject.org/carbonbudget/14/data.htm, Accessed August 12, 2015.
GWEC (Global Wind Energy Council), 2015. Global wind report annual market update 2014, http://www.gwec.net/wp-content/uploads/2015/03/GWEC_Global_Wind_2014_Report_LR.pdf, Accessed July 15, 2015.
Hooker-Stroud, A., P. James, T. Kellner, and P Allen, 2015. Understanding the challenges and opportunities in managing hourly variability in a 100% renewable energy system for the UK, Carbon Management, doi:10.1080/17583004.2015.1024955.
IEA (International Energy Agency), 2014a. 2014 Key world energy statistics, http://www.iea.org/publications/freepublications/publication/keyworld2014.pdf, Accessed August 1, 2015.
IEA (International Energy Agency), 2014b, Renewable energy medium-term market report 2014.
IEA (International Energy Agency), 2015, Statistics, http://www.iea.org/statistics/statisticssearch/, Accessed June 10, 2015.
IEA-PVPS (International Energy Agency-Photovoltaic Power Systems Programme) 2015, PVPS Annual report 2014, http://iea-pvps.org/index.php?id=6&eID=dam_frontend_push&docID=2557, Accessed 25 July 2015.
IEA (International Energy Agency), 2005, Energy use in the new millennium, https://www.iea.org/publications/freepublications/publication/millennium.pdf, Accessed Sept. 8, 2015.
IHA (International Hydropower Association), 2015, Country profiles, http://www.hydropower.org/country-profiles, Accessed August 1, 2015.
IPCC (Intergovernmental Panel on Climate Change), 2000. Special Report on Emission Scenarios (SRES), http://sres.ciesin.org/final_data.html, Accessed November 19, 2015.
Jacobson, M.Z., W.G. Colella, and D.M. Golden, 2005. Cleaning the air and improving health with hydrogen fuel cell vehicles, *Science*, *308*, 1901-1905.
Jacobson, M.Z., Y.J. Kaufmann, Y. Rudich, 2007, Examining feedbacks of aerosols to urban climate with a model that treats 3-D clouds with aerosol inclusions, *J. Geophys. Res.*, *112*, D24205, doi:10.1029/2007JD008922.
Jacobson, M.Z., 2009. Review of solutions to global warming, air pollution, and energy security, *Energy & Environmental Science*, 2, 148-173, doi:10.1039/b809990c.
Jacobson, M.Z., and M.A. Delucchi, November 2009. A path to sustainable energy by 2030, *Scientific American*.
Jacobson, M.Z., 2010. Enhancement of local air pollution by urban CO_2 domes, *Environmental Science, and Technology, 44*, 2497-2502.
Jacobson, M.Z., 2010, Short-term effects of controlling fossil-fuel soot, biofuel soot and gases, and methane on climate, Arctic ice, and air pollution health, *J. Geophys. Res., 115*, D14209, doi:10.1029/2009JD013795.
Jacobson, M.Z., and M.A. Delucchi, 2011. Providing all Global Energy with Wind, Water, and Solar Power, Part I: Technologies, Energy Resources, Quantities and Areas of Infrastructure, and Materials, *Energy Policy*, 39, 1154-1169, doi:10.1016/j.enpol.2010.11.040.
Jacobson, M. Z., 2012. *Air Pollution and Global Warming: History, Science, and Solutions*, Second Edition, Cambridge University Press, Cambridge, 375 pp.
Jacobson, M.Z., R.W. Howarth, M.A. Delucchi, S.R. Scobies, J.M. Barth, M.J. Dvorak, M. Klevze, H. Katkhuda, B. Miranda, N.A. Chowdhury, R. Jones, L. Plano, and A.R. Ingraffea, 2013. Examining the feasibility of converting New York Country's all-purpose energy infrastructure to one using wind, water, and sunlight, *Energy Policy*, 57, 585-601.
Jacobson, M.Z., M.A. Delucchi, A.R. Ingraffea, R.W. Howarth, G. Bazouin, B. Bridgeland, K. Burkhart, M. Chang, N. Chowdhury, R. Cook, G. Escher, M. Galka, L. Han, C. Heavey, A. Hernandez, D.F. Jacobson, D.S. Jacobson, B. Miranda, G. Novotny, M. Pellat, P. Quach, A. Romano, D. Stewart, L. Vogel, S. Wang,

H. Wang, L. Willman, T. Yeskoo, 2014. A roadmap for repowering California for all purposes with wind, water, and sunlight, *Energy, 73,* 875-889, doi:10.1016/j.energy.2014.06.099.

Jacobson, M.Z., M.A. Delucchi, G. Bazouin, Z.A.F. Bauer, C.C. Heavey, E. Fisher, S. B. Morris, D.J.Y. Piekutowski, T.A. Vencill, T.W. Yeskoo, 2015a, 100% clean and renewable wind, water, sunlight (WWS) all-sector energy roadmaps for the 50 United States, *Energy and Environmental Sciences, 8*, 2093-2117, doi:10.1039/C5EE01283J.

Jacobson, M.Z., M.A. Delucchi, M.A. Cameron, and B.A. Frew, 2015b. A low-cost solution to the grid reliability problem with 100% penetration of intermittent wind, water, and solar for all purposes, *Proc. Nat. Acad. Sci.*, *112*, doi: 10.1073/pnas.1510028112.

Jacobson, M.Z., M.A. Delucchi, G. Bazouin, M.J. Dvorak, R. Arghandeh, Z. A.F. Bauer, A. Cotte, G.M.T.H. de Moor, E.G. Goldner, C. Heier, R.T. Holmes, S.A. Hughes, L. Jin, M. Kapadia, C. Menon, S.A. Mullendore, E.M. Paris, G.A. Provost, A.R. Romano, C. Srivastava, T.A. Vencill, N.S. Whitney, and T.W. Yeskoo, 2016a, A 100% wind, water, sunlight (WWS) all-sector energy plan for Washington State, *Renewable Energy*, *86*, 75-88.

Jacobson, M.Z., C. Clack, M.A. Delucchi, M.C. Cameron, 2016b, 100% grid reliability in 20 regions of the world with 100% penetration of intermittent wind, water, and solar for all purposes, in preparation.

JPL (Jet Propulsion Laboratory), 2010, Dataset Discovery, http://podaac.jpl.nasa.gov/datasetlist?ids=Platform&values=QUIKSCAT, Processed by D. Whitt and M. Dvorak, Accessed February 23, 2012.

Lepeule, J., F. Laden, D. Dockery, and J. Schwartz, 2012. Chronic exposure to fine particles and mortality: An extended follow-up of the Harvard six cities study from 1974 to 2009, *Environmental Health Perspectives, 120*, 965-970.

LeQuere et al., 2015, Global carbon budget 2014, *Earth Syst. Sci. Data 7*, 47-85, 2015.

Linowes, L., 2012. Wind Benefit Inflation: JEDI (NREL) Model Needs Reality Check. http://www.masterresource.org/2012/12/wind-benefit-inflation-jedi-nrel-2/, Accessed Dec. 16, 2012.

Lund, J. W. and T.L. Boyd, 2015. Direct Utilization of Geothermal Energy 2015 Worldwide Review, World Geothermal Congress 2015 Conference Proceedings, Melbourne, Australia, 19-25 April 2015.

Marine Renewables Canada, 2013. Marine renewable energy in Canada and the global context, http://www.marinerenewables.ca/wp-content/uploads/2012/11/State-of-the-Canadian-MRE-Sector-20131.pdf, Accessed August 1, 2015.

Mathiesen, B.V., H. Lund, D. Connolly, H. Wenzel, P.A. Ostergaard, B. Moller, S. Nielsen, I. Ridjan, P. Kamoe, K. Sperling, F.K. Hvelplund, 2015, Smart energy systems for coherent 100% renewable energy and transport solutions, Applied Energy, 145, 139-154.

Negawatt Association, 2015. The Negawatt 2050 scenario, http://www.negawatt.org/english-presentation-p149.html, Accessed July 31, 2015.

NREL (National Renewable Energy Laboratory), 2012a. Wind resources by class and country at 50 m, http://en.openei.org/datasets/dataset/wind-resources-by-class-and-country-at-50m, Accessed June 11, 2015.

NREL (National Renewable Energy Laboratory), 2012b. Global Solar Opportunity Tool, http://maps.nrel.gov/global_re_opportunity#, Accessed September 9, 2015.

NREL (National Renewable Energy Laboratory), 2013, Jobs and Economic Development Impact Models (JEDI). http://www.nrel.gov/analysis/jedi/download.html. Accessed October 27, 2013.

NREL (National Renewable Energy Laboratory), 2015, Concentrating Solar Power Projects by Country. http://www.nrel.gov/csp/solarpaces/by_country.cfm. Accessed July 22, 2015.

OECD (2014), *The Cost of Air Pollution: Health Impacts of Road Transport*, OECD Publishing, Paris. DOI: http://dx.doi.org/10.1787/9789264210448-en.

Parsons-Brinckerhoff, *Powering the Future: Mapping our Low-Carbon Path to 2050*, Dec. (2009). https://www.pbworld.com/pdfs/powering_the_future/pb_ptf_full_report.pdf, Accessed May 2, 2015.

Pope, C.A. III, R.T. Burnett, M.J. Thun, E.E. Calle, D. Krewski, K. Ito, and G.D. Thurston, 2002. Lung cancer, cardiopulmonary mortality, and long-term exposure to fine particulate air pollution, Journal Amer. Med. Assoc., 287, 1132-1141.

Price-Waterhouse-Coopers, *100% Renewable Electricity: A roadmap to 2050 for Europe and North Africa*, 2010, www.pwcwebcast.co.uk/dpliv_mu/100_percent_renewable_electricity.pdf, Accessed May 2, 2015.

REN21 (Renewable Energy Policy Network for the 21st Century), 2015, Renewables 2015 Global Status Report, http://www.ren21.net/wp-content/uploads/2015/07/REN12-GSR2015_Onlinebook_low_nolinks.pdf, Accessed 1 August 2015.

Shindell, D., J.C.I. Kuylenstierna, E. Vignati, R. van Dingenen, M. Amann et al., 2012. Simultaneously mitigating near-term climate change and improving human health and food security, *Science, 335*, 183-189.

Smith, J. C., et al., 2013. Transmission planning for wind energy in the United States and Europe: status and prospects, WIREs Energy Environ 2: 1-13.

Teske, S., S. Sawyer, O. Schafer, T. Pregger, S. Simon, and T. Naegler, 2015, Energy revolution: A sustainable world energy outlook 2015, http://www.greenpeace.org/international/en/publications/Campaign-reports/Climate-Reports/Energy-Revolution-2015/, Accessed Sept. 22, 2015.

WHO (World Health Organization), 2014. 7 million premature deaths annually linked to air pollution, http://www.who.int/mediacentre/news/releases/2014/air-pollution/en/, Accessed June 15, 2015.

WHO, 2014, Global Health Observatory Data Repository, http://apps.who.int/gho/data/node.main.156 Accessed 2 July 2015.

World Bank, 2015a, World development indicators: Contribution of natural resources to gross domestic product, http://wdi.worldbank.org/table/3.15#, Accessed June 17, 2015.

World Bank, 2015b, Labor force, total, http://data.worldbank.org/indicator/SL.TLF.TOTL.IN/countries, Accessed June 17, 2015.

World Bank, 2015c, Urban population (% of total), http://data.worldbank.org/indicator/SP.URB.TOTL.IN.ZS, Accessed September 8, 2015.

World Bank, 2014, Infrastructure, Passenger cars (Per 1000 people), http://data.worldbank.org/indicator/IS.VEH.PCAR.P3, Accessed Fall 2014

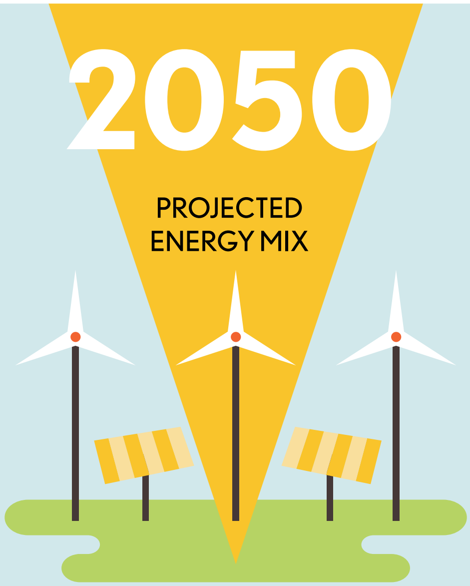
World Bank, 2015, Electricity production from hydroelectric sources, http://data.worldbank.org/indicator/EG.ELC.HYRO.ZS, Accessed August 1, 2015.

Zero Carbon Britain, 2013, *Zero Carbon Britain: Rethinking the future*, http://zerocarbonbritain.org/images/pdfs/ZCBrtflo-res.pdf, Accessed May 2, 2015.

Exhibit 30

100% OREGON

Transition to 100% wind, water, and solar (WWS) for all purposes
(electricity, transportation, heating/cooling, industry)



Residential rooftop PV
4%

Solar PV plants
8%

CSP plants
5%

Onshore wind
32.5%

Offshore wind
15%

Commercial/govt rooftop PV
2.2%

Wave devices
1%

Geothermal
5%

Hydroelectric
27.3%

Tidal turbines
0.05%

40-Year Jobs Created

Number of jobs where a person is employed for 40 consecutive years

Operation jobs: **14,235**

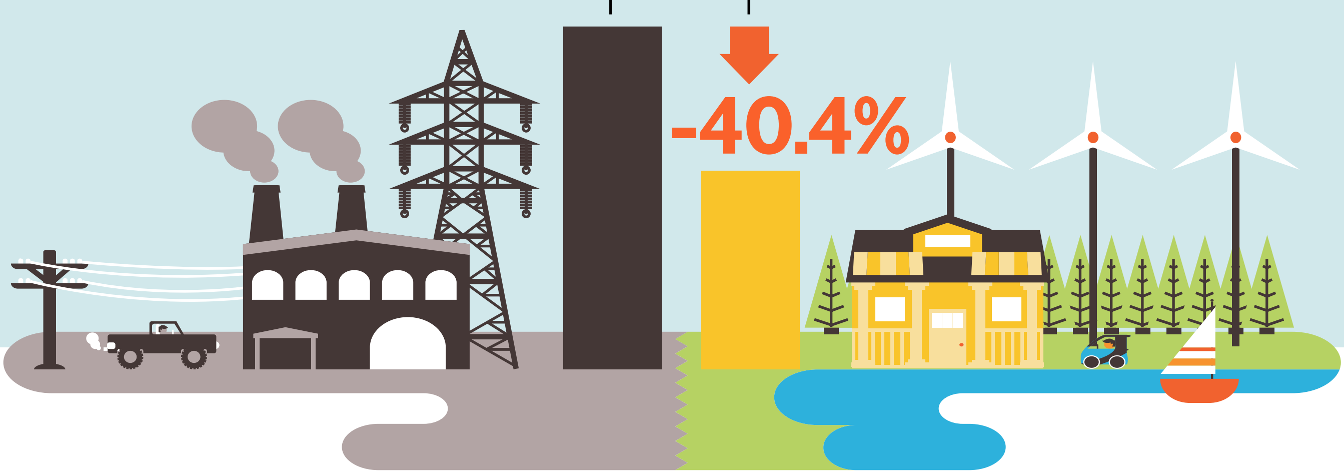
Construction jobs: **21,564**

=10,000

Using WWS electricity for everything, instead of burning fuel, and improving energy efficiency means you need much less energy.

Current demand

Wind, Water, Solar



VISIT THESOLUTIONSPROJECT.ORG TO LEARN MORE AND 100.ORG TO JOIN THE MOVEMENT

THE SOLUTIONS PROJECT

Data from Stanford University - For more information, visit http://go100.me/50StateTargets

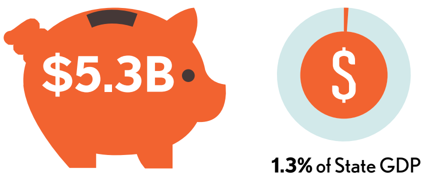
FOLLOW US ON 100isNow SolutionsProj

100% OREGON

Transition to 100% wind, water, and solar (WWS) for all purposes (electricity, transportation, heating/cooling, industry)

Avoided Mortality and Illness Costs

Avoided health costs per year:



1.3% of State GDP

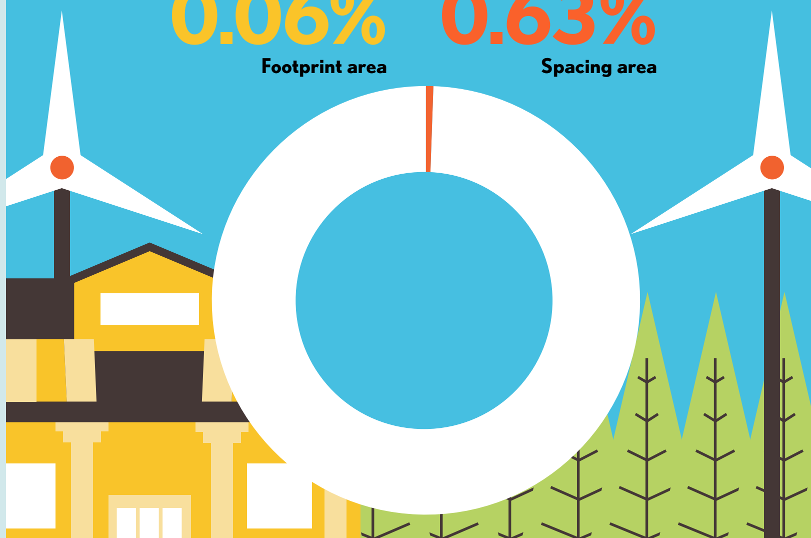
Air pollution deaths avoided every year: **453**

Plan pays for itself in as little as **3.1** years from air pollution and climate cost savings alone

Percentage of Oregon Land Needed for All New WWS Generators

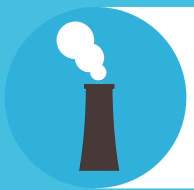
0.06% Footprint area

0.63% Spacing area



Future Energy Costs 2050

BAU (Business as usual) WWS (Wind, water, solar)



U.S. average fossil-fuel energy costs*

9.02 c/kWh

*Health and climate external costs of fossil fuels are another 5.7c/kWh

State average WWS electricity costs

10.01 c/kWh

Money in Your Pocket

 = $2,000

Annual energy, health, and climate cost savings per person in 2050: **$5,232**

Annual energy cost savings per person in 2050: **$33**

VISIT THESOLUTIONSPROJECT.ORG TO LEARN MORE AND 100.ORG TO JOIN THE MOVEMENT

THE SOLUTIONS PROJECT

Data from Stanford University - For more information, visit http://go100.me/50StateTargets

FOLLOW US ON 100isNow SolutionsProj

Exhibit 31

The Australia Institute
Research that matters.

Be careful of what you wish for

The economic impacts of Queensland's unconventional gas experiment and the implications for Northern Territory policy makers.

Discussion paper

Mark Ogge
November 2015

ABOUT THE AUSTRALIA INSTITUTE

The Australia Institute is an independent public policy think tank based in Canberra. It is funded by donations from philanthropic trusts and individuals and commissioned research. Since its launch in 1994, the Institute has carried out highly influential research on a broad range of economic, social and environmental issues.

OUR PHILOSOPHY

As we begin the 21st century, new dilemmas confront our society and our planet. Unprecedented levels of consumption co-exist with extreme poverty. Through new technology we are more connected than we have ever been, yet civic engagement is declining. Environmental neglect continues despite heightened ecological awareness. A better balance is urgently needed.

The Australia Institute's directors, staff and supporters represent a broad range of views and priorities. What unites us is a belief that through a combination of research and creativity we can promote new solutions and ways of thinking.

OUR PURPOSE – 'RESEARCH THAT MATTERS'

The Institute aims to foster informed debate about our culture, our economy and our environment and bring greater accountability to the democratic process. Our goal is to gather, interpret and communicate evidence in order to both diagnose the problems we face and propose new solutions to tackle them.

The Institute is wholly independent and not affiliated with any other organisation. As an Approved Research Institute, donations to its Research Fund are tax deductible for the donor. Anyone wishing to donate can do so via the website at https://www.tai.org.au or by calling the Institute on 02 6130 0530. Our secure and user-friendly website allows donors to make either one-off or regular monthly donations and we encourage everyone who can to donate in this way as it assists our research in the most significant manner.

Level 5, 131 City Walk
Canberra, ACT 2601
Tel: (02) 61300530
Email: mail@tai.org.au
Website: www.tai.org.au

Summary

The gas industry says that unconventional gas development brought an economic and jobs boom to Queensland, and promises the same for the Northern Territory. Territorians should test the claims of the industry in Queensland to determine the likely economic and jobs impacts of unconventional gas development in the Northern Territory.

In contrast to the economic benefits promised , recent gas industry funded studies of the economic and social impacts of gas in Queensland's unconventional gas fields have found:

- Local business stakeholders reported a deterioration in:
    - Financial capital
    - Local Infrastructure
    - Local skills
    - Social cohesion
    - The local environment
- Unconventional gas has reduced community wellbeing:
    - Fewer than one in four local people approved of the unconventional gas industry, with less than 6% believing it would "lead to something better".
- Unconventional gas creates few additional jobs:
    - There were virtually no spillover jobs created in local retail or manufacturing.
    - Gas jobs will be slashed by 80% at the end of the construction period.
- For every 10 unconventional gas jobs created, 7 service sector jobs were lost.

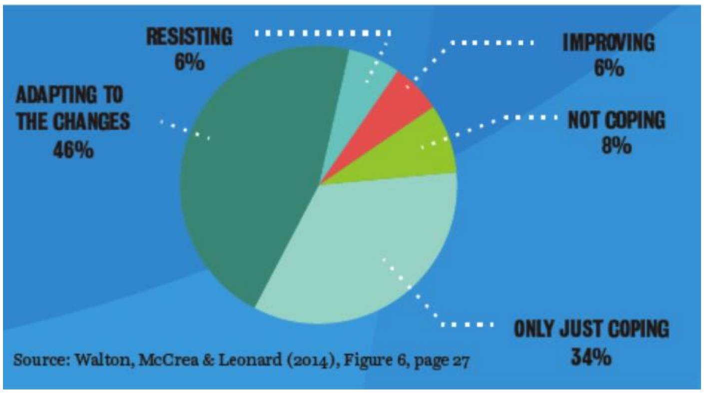
Figure 1: The impact of unconventional gas development on local businesses.

How did local business stakeholders in Queensland's Darling Downs perceive the impact of unconventional gas and mining on their region?

Source: CSRM University of Queensland

Financial capital	Worse
Infrastructure	Worse
Labour force skills	Worse
Social networks	Worse
Environment	Worse

Figure 2: The social impacts of unconventional gas development on communities in Queensland's Darling Downs



There have also been few economic benefits for the wider economy. The industry emphasises the high *value* of the gas it exports, but the value of gas exports largely flow to the gas companies thather than to the Australian community. As the Reserve Bank of Australia concluded:

> The effect on Australian living standards will be less noticeable than [the increase in gas production] given the low employment intensity of LNG production, the high level of foreign ownership of the LNG industry and, in the near term, the use of deductions on taxation payments.[1]

Queensland's experience shows that reality does not match the unconventional gas industry's claims. Few benefits are realised outside the gas industry, and there are serious social and economic effects on local communities and existing businesses.

[1] Cassidy N and Kosev M, (2015) Australia and the Global LNG Market, RBA

Table of Contents

Introduction

When seeking development approval, oil and gas companies justify their projects' significant environmental and social harm on the grounds that the projects will bring jobs and economic growth.

The huge profits at stake encourage companies to exaggerate the economic benefits of their projects and downplay their negative effects. These economic claims are made in formal approval process, public relations activities and lobbying of policy makers.

This kind of exaggeration has become routine for many resource companies, often reaching almost comic proportions. Notorious cases include the Rio Tinto Warkworth coal mine expansion in NSW where the company claimed it would create 44,000 additional jobs despite the expansion only requiring 130 additional workers. The NSW Land and Environment Court rejected the companies claims and overturned the approval, a decision that was upheld by the Supreme Cort of NSW. Similarly the proponants of the proposed the Carmichael coal mine the project would create 10,000 jobs. When challenged in court the companies own economic expert acknowledgers actual figure was less than 1,476 jobs.

In 2013 the Australian Petroleum Production and Exploration Association APPEA claimed that the oil and gas industry had created a 100,000 new jobs in a single year. According to The Australian Bureau of Statistics the oil and gas industry in Australia added only 9,400 jobs that year, and employed 20,700 people in total.[2] Even countinag all the addition construction jobs would come nowhere near the 100,000 jobs claimed. These additional construction jobs woud have come largely at the expense of jobs in other industries, patricularly given the very tight labour market at the time.

The absurdity of the claims belies the seriousness of the deception.

These projects have serious environmental and social impacts that are too often ignored by policy makers and bureaucrats who have been willing to accept the assurances of resource companies with little scrutiny applied to their claims. This has sometimes led to serious environment and social impacts for local communities from projects that provide little benefit to the wider population.

[2] Thae Austraila Institute facts Fight Back June 30 2013. http://www.factsfightback.org.au/did-the-gas-industry-create-100000-jobs-last-year-check-the-facts/

The huge unconventional gas projects approved in Queensland in 2010 are a case in point. The economic claims of the proponants were not tested by the government, despite its obligation to objectively assess the projects. Recent research examined in this paper clearly shows that few of the promised benefits have materialised and existing businesses and entire industries have been badly affected. Long-term jobs have been sacrificed for short-term gas construction jobs.

Only 6% of local people living in gasfield areas think that the industry has improved their lives – as many as are actively resisting it. As well as active resisters, a further 42% say that they are “not coping” or “only just coping” with the changes the industry has made to their lives. Actual royalty payments are a small fraction of the estimates made at approval and flow on economic activity failed to materialse, as companies bypassed local industry and suppliers in favour of global supply chains.

The Northern Territory government has issued unconventional gas licenses for almost the entire territory. Speculative gas interests have a strong incentive to increase the value of their licenses by gaining environmental approvals and government promises to subsidise infrastructure.

Northern Territory policy makers can learn from the experience in Queensland. The economic claims of the unconventional gas industry must be subject to scrutiny and due diligence. Projects should only proceed if they provide a net benefit to the Territory community, not just quick profits for gas companies.

1. The impacts of unconventional gas developments on local businesses

While some people and businesses benefit from unconventional gas development, many other businesses and industries can be negatively impacted and jobs in other sectors are often lost as a result.

The most advanced unconventional gas development in Australia is in Queensland's Darling Downs. The gas industry uses this region as an example of the economic benefits that unconventional gas provides local communities. The research tells a more complicated story.

The most detailed examination of the economic impacts of unconventional gas development in the Darling Downs is a study carried out between 2008 and 2013 by the industry-funded Sustainable Minerals Institute SMI at the University of Queensland. [3]

This study surveyed stakeholders from different sectors in the local community including the local business community, agriculture, local government, advocacy groups and environmental consultants, as well as the mining and unconventional gas industries.

The survey asked stakeholders to assess the effect of unconventional gas and mining in the region over a five-year period on the following key indicators:

1. **Financial capital:** Available revenue streams and economic resources.
2. **Built capital:** The physical infrastructure such as buildings, transport, equipment.
3. **Social capital:** The degree to which people know each other and collaborate and the level of trust people have in local organisations and institutions.
4. **Human capital:** Assets such as skills, knowledge, abilities and good health possessed by individuals that enable them to work, earn a living, contribute to society and thereby build other forms of capital.
5. **Natural capital**: Key natural resources, such as water, land, clean air, wildlife and forests that people can access for lifestyle or livelihood purposes.

[3] Everingham, J., Collins, N., Rodriguez, D. Cavaye, J., Vink, S., Rifkin, W. & Baumgartl, T. (2013) *Energy resources from the food bowl: an uneasy co-existence. Identifying and managing cumulative impacts of mining and agriculture. Project report*. CSRM, The University of Queensland: Brisbane.

All stakeholder groups other than those representing mining and unconventional gas believed that the development of mining and unconventional gas had a negative impact on all or most types of capital. Even the mining and unconventional gas industries thought that local infrastructure had deteriorated as a result of mining and unconventional gas development in the region.

Figure 3: Stakeholder responses assessing the change in different types of capital over the last 5 years as a result of interaction between gas and other industries.

	Financial capital	Human capital	Built capital	Social capital	Natural capital
Gas	Better	Better	Worse	Better	Better
Mining	Better	Better	Worse	Better	Better
Agriculture	Worse	Worse	Worse	Worse	Worse
Local business	Worse	Worse	Worse	Worse	Worse
Local government	Worse	Better	Worse	Same	Same
Community	Worse	Better	Worse	Worse	Worse
Advocacy	Worse	Worse	Worse	Worse	Worse

Far from mining and unconventional gas providing economic benefits, local businesses felt that it had reduced financial capital, human capital, infrastructure, social capital and natural capital.

Local businesses have to compete with inflated gas industry wages if they want to recruit and retain staff and they experience increased rent and competition for services (particularly trade and mechanical repairs). There are also disruptions to farmers from the rollout of access roads, pipelines, water treatement plants and other infrastructure. Big increases in truck traffic tend to disrupt other forms of transport and damage roads.

Some businesses do benefit. Motels, bars and fast food chains experience a burst of demand during the brief construction phase, but may struggle afterwards. Waste disposal companies can profit from storing, transporting and treating the millions of litres of toxic "produced" or "flow-back" water and salt from the extraction process.

Some stakeholders discussed the effect on existing local businesses:

> Obviously if you've got a major engineering or earth moving business, you attract business, you're doing incredibly well, or a motel.
>
> But, if you work in town at a local shop, or the council, you're doing incredibly poorly, because your rents have gone through the roof and suddenly you're flat out paying to be able to live in town. For us, we're seeing increased costs.
>
> All our professional services are $100 an hour plus, whereas they used to be [in the] 40s and 50s. Freight is dearer. We can't get labour. We're relying on backpackers a lot more because we just can't get permanent staff. So, it's quite an added cost to one sector of the community, while the other sector booms. [4]

Having to compete with inflated resource industry wages was also of great concern:

> What they're paying for wages [in some towns] is two and half times what the wage should be – just to hold men. That's forcing consumer goods up, to try to cover the costs of those wages… So it's all spinning down the line… [For example] from a hardware perspective, anyone doing renovations to their home, even just the little bits are all getting more expensive because these guys are trying to cover the increase in wages that they've had to pay to retain men. And the [resources] companies are walking into businesses and offering staff – mainly mechanics… huge wages. 5

Other stakeholders described the corrosion of social capital:

> [I]n regards to a divide between people, not just landholders versus townies, but for instance I've got a lot of friends who used to work in agriculture and now work for gas companies – a lot of them. And some family members don't speak to them anymore because they're still on the land...
>
> But even in towns now… once you would go to the local pub in Dalby, it was all full of farmers and that sort of thing and now you've got guys in their high vis' and after a few rums things are getting… they do, it's starting to get quite ugly. There's quite a bit of animosity going on. And agricultural communities have never been like that – they're not. And now that's building up pretty much. [6]

It is clear from interviews with businesses in unconventional gas development areas that the industry brings substantial costs. The CSRM study showed that business stakeholders perceived the costs as outweighing the benefits. Territory business

[4] Everingham et al, p 38.
[5] Everingham et al, p 39.
[6] Everingham et al, p 51.

organisations and policy makers should be aware of how this has played out in Queensland when considering the expansion of the gas industry in the NT.

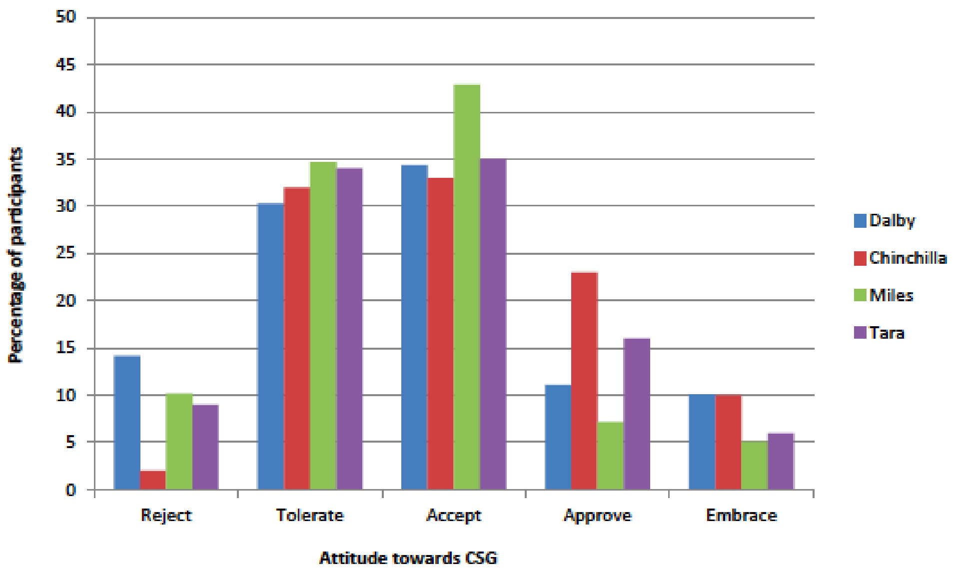
Negative impacts on local businesses also affect communities at the social level. The next section examines the social impacts in more detail.

2. Impacts on local communities

Unconventional gas development in Queensland's Darling Downs distresses local communities. Few people approve of the industry and even fewer believe it will improve conditions.

A recent CSIRO survey of the Western Darling Downs found that almost half the local population was "only just coping" with, "not coping" with or actively resisting the changes to their communities caused by unconventional gas development. This study was undertaken by researchers funded by the largest unconventional gas companies in Queensland, including Australia Pacific LNG and QGC.[7]

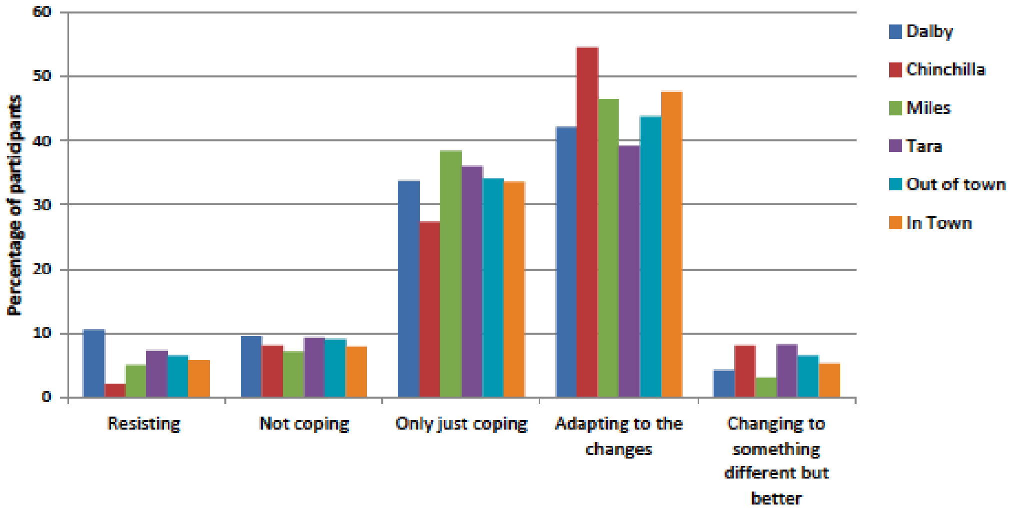
Figure 4: Attitudes towards unconventional gas in the region by suberegions. CSIRO.



Less than a quarter of people surveyed approved of the unconventional gas industry. Only 6% of people felt the community was improving as a result of the industry, while many were struggling to cope with the changes the industry had brought.

[7] Walton, A., McCrea, R., & Leonard, R. (2014). *CSIRO survey of community wellbeing and responding to change: Western Downs region in Queensland.* CSIRO Technical report: CSIRO, Australia.

Figure 5: Community responses to unconventional gas development in the Western Downs Queensland. CSIRO

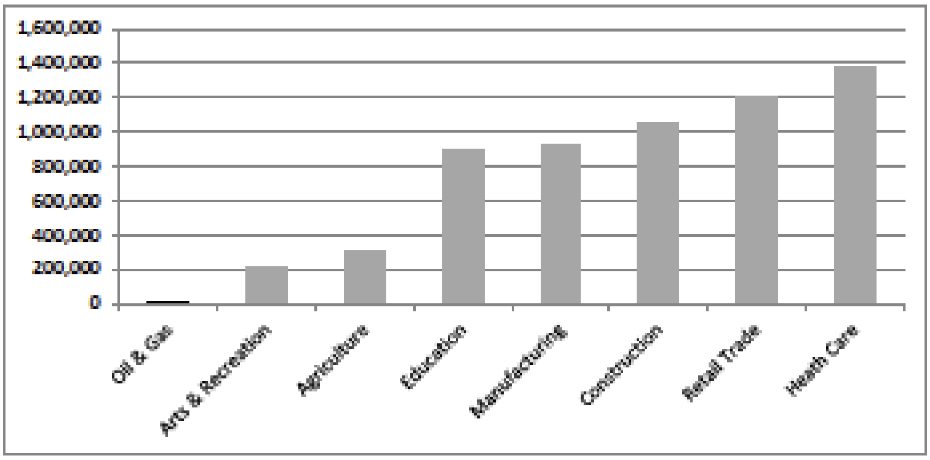


3. Unconventional gas does not employ many people.

According to the Australian bureau of statistics, in May 2015 the entire oil and gas industry in Australia employed 27,500 Australian workers, or less than a quater of 1% of the Australian workforce.[8]

By way of comparison, the total employment provided by the oil and gas industry is considerably less than the retail hardware store Bunning's, which employs 33,000.[9]

Figure 6: Employment in Australia by selected industry.



Employment in the gas industry is likely to decline. The vast majority of gas jobs are during the construction phase. As the construction phase winds up, the unconventional gas companies operating in Queensland are cutting their workforces by around 80%.[10]

Territorians seeking employment for any unconventional project in the Northern Territory will have to compete with experienced workers from interstate. The gas industry requires experienced, skilled workers. With the wind down of the CSG construction boom in Queensland, there is a large pool of highly-qualified workers who

---

[8] ABS (2013a). *6291.0.55.003 Labour Force, Australia, Detailed, Quarterly, September 2015*, Australian Bureau of Statistics, Accessed 11/11/15, http://www.abs.gov.au/ausstats/abs@.nsf/mf/6202.0

[9] Bunnings (2013). *About Us: Who we are*, Bunnings, viewed 21 November 2013, <http://www.bunnings.com.au/about-us>.

[10] Bureau of Resource and Energy Economics, Resource and Energy Major Projects 2013.

are more likely to fill positions than unskilled Territorians with no experience in gas field construction and operation.

Experience in Queensland has shown that construction workforces are almost entirely male non-residential workers living in workers camps on the outskirts of towns. These workers are often referred to as fly-In, fly-out (FIFO) or drive-in, drive-out (DIDO). Few people from local regional communities are likely to be employed in either the construction or the operational phases of the gas fields.

If locals are employed on these projects, they are unlikely to be previously unemployed people getting a job. When the gas industry employs local people, they tend to be skilled workers who relocate from local manufacturing and agriculture.

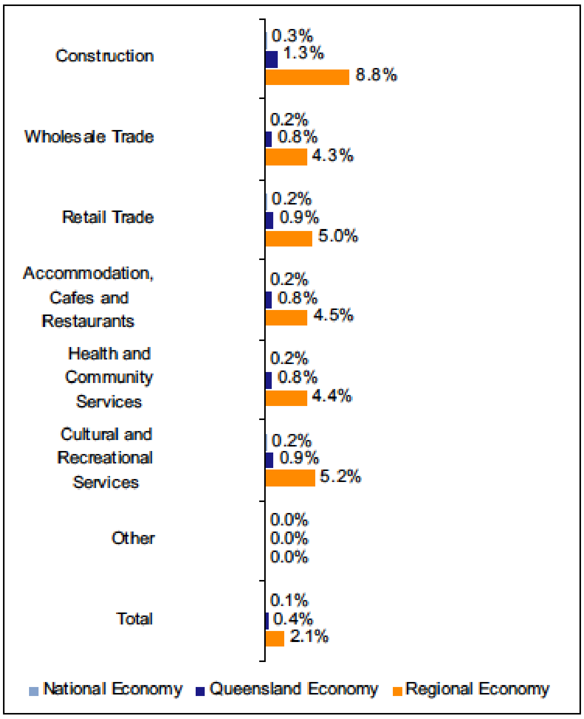
As explained above in section 1, this disrupts local businesses and forces them to compete with inflated gas industry wages to recruit or retain staff.

4. Promise versus reality

As discussed I section 3, the unconventional gas extraction employs relatively few people. These jobs are mostly short term include few people from local regional communities. However the industry claims that the flow on effects result in people being employed elsewhere in the community. However recent rearearch shows that the employment effects have been very different to industry industry claims.

Fore example, the original economic impact statement used to gain approval for the largest unconventional gas project in Queensland, Australia Pacific LNG (APLNG), claimed that the construction phase of the project would increase regional employment in the retail trade by 5 percent, and a range of regional service sectors by between 4.5 and 5.2 percent . [11]

Figure 7: Australia Pacific LNG direct and indirect employment by industry



Source: KPMG, APLNG EIS Economic Impact Assessment report, Chart 5.3 p29

However the reality was very different. At the height of the construction boom in 2013 a study was undertaken by the Gas Industry Social and Environmental Research Alliance (GISERA) into the local economic impacts of the unconventional gas boom.

[11] KPMG, APLNG EIS Economic Impact Assessment report, Chart 5.3 p29.

The study examined the actual economic impacts of unconventional gas development in Queensland's gas fields. As we can see in figure 5 below, the study found that In fact, while there was an increase in short term construction related jobs (construction and professional services), there were virtually no additional jobs in retail or manufacturing as a result of unconventional gas development. There was also a loss of seven service sector jobs for every 10 unconventional gas jobs in the region. See 'Services' row in Figure 8 below.[12]

Figure 8: Unconventional gas employment spillovers in different sectors of Queensland's Darling Downs economy.

	Elasticity	Additional job for each new CSG job
Local goods sector		
Construction	0.832 (0.426) *	1.412
Professional services	0.704 (0.259) **	0.412
Retail trade	0.011 (0.140)	0.024
Services†	-0.205 (0.230)	-0.732
Traded sector		
Manufacturing	0.068 (0.199)	0.160

Notes: Elasticity values are 2SLS estimations for coefficient ψ in equation (2). The number of CSG wells in an SLA is used as instrument for the log change of mining employment. Values estimated using sample 3 (n = 48). F-stat first-stage = 10.74. Robust clustered std. errors at LGA levels in parentheses. *p < .10. **p < .05.
†Services sector include employment in accommodation, rental agencies, transport and 'other services'.

Source: Flemming and Measham (2013)

In other words, the unconventional gas boom had virtually no employment benefits outside of the gas industry itself. In the words of the authors, "job spillovers into non-mining employment are negligible". It also shows that service sector jobs were lost and that the that the jobs benefits employment gains gained were almost entirely short term construction jobs and (largely construction phase related) professional services jobs.

The Queensland unconventional gas boom is one of the largest and most rapid resource expansions ever seen, and yet it led to virtually no increase in employment in local retail or manufacturing, and a loss of long-term service jobs.

The lack of any increase in retail employment in local communities is largely a result the predominance of no-resident workers living in self-contained workers camps.

[12] Fleming, D. and Measham, T. (2013) Local economic impacts of an unconventional energy boom: the coal seam gas industry in Australia. Report to the Gas Industry Social and Environmental Research Alliance (GISERA). June 2013. CSIRO, Canberra.

These employees work long shifts that limit opportunities to spend their income in the local community.

The lack of flow on manufacturing jobs is the result of the gas industry's preference for sourcing materials and equipment from overseas. For example, the huge LNG export and processing facilities at Gladstone in Queensland were entirely designed and built overseas.

All three export terminals were built by the global oil and gas engineering company Bechtel. On their website, Bechtel promote their "efficiency" in not employing Australians. The website page shown in Figure 8 describes all three of the Gladstone LNG Processing plants and export terminals as being designed by Bechtel engineers in Houston, Delhi and Shanghai, to be built in the Philippines, Indonesia and Thailand. The terminals were then floated over to Australia to be assembled.[13]

Figure 9: Bechtel description of design and construction process for their Curtis Island LNG terminals in Queensland.

An efficient effort

Because of overlapping schedules, close proximity, and good cooperation, each project and all three customers have benefited from economies of scale and efficiency orchestrated by Bechtel.

For the sake of quality, speed, and cost control, Bechtel engineers in Houston, New Delhi, and Shanghai geared their designs for the three Curtis Island plants to modular construction. At Bechtel facilities in the Philippines, Indonesia, and Thailand, colleagues have been building some 250 modules for use in all three complexes.

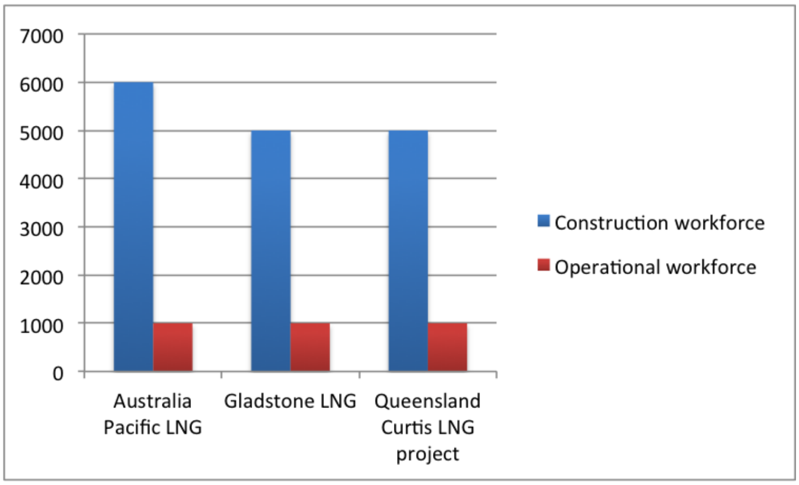
Among the heaviest of 250 modular components: a propane chiller that weighs 2,500 metric tons—equivalent to more than five of the largest 747s, fully loaded.

[13] Bechtel website http://www.bechtel.com/projects/curtis-island-lng/ accessed 10/11/15.

5. Boom and bust

According to the Office of the Chief Economist of Australia, the three unconventional gas projects in Queensland employed 16,000 people during their brief[14] construction phase. This is falling by over 80% to 3,000 employees as the projects enter their operational phase.[15] This will represent less than 0.13% of Queensland's total workforce of over 2.3 million. [16]

Figure 10: Queensland unconventional gas operation and construction employment.



Source: Office of the Chief Economist of Australia (2015).

The construction workforces may have been considerably smaller than reported by the Office of the Chief Economist. The office based the numbers on "fact sheets provided by the companies".[17] APLNG, the largest of Queensland's LNG projects says in its Economic Impact Assessment that "over the 11-year construction phase, there will be an approximate average of 3,300 people working on the Australia Pacific LNG project each year. Employment will peak from 2012 to 2014 inclusive". This is a little over half the number reported by the Office of the Chief Economist but would still represent more than a two-thirds reduction in the workforce between the construction and operational phase.

[14] The length of the construction period varies between the projects. In the case the Gladstone LNG, the construction period was 4 years. URS (2009) GLNG Economic Impact Statement.

[15] Office of the Chief Economist, Resources and Energy Major Projects list April 2015. Viewed on 11 November 2015, <http://www.industry.gov.au/Office-of-the-Chief-Economist/Publications/Pages/Resources-and-energy-major-projects.aspx>

[16] ABS Labour Force Statistics.

[17] Correspondence with the Office of the Chief Economist.

Any unconventional gas project in the Northern Territory would employ far fewer workers than in Queensland.

A large proportion of both the construction and operational workforce in Queensland worked on assembling the LNG terminals at Gladstone. Additional LNG terminals will not be required in the Northern Territory as the gas will be exported via the Queensland terminals.

There is also likely to be a large pool of experienced gas workers in Western Australia and Queensland who are well placed to fill Northern Territory unconventional gas jobs. The three Queensland LNG terminals, the Northern Territory Inpex project and several Western Australian LNG terminals and offshore gas fields were all built simultaneously. The decision to allow all these projects to be built simultaneously created an acute skills shortage at the time. With the wind down of the construction phase of these projects there is an abundance of interstate skilled gas construction workers who will be far better placed to work in any gas projects in the NT than unemployed NT residents who lack these skills.

To the extent that NT residents are employed, they are likely to be skilled workers already employed in other industries, particularly manufacturing and agriculture. This effect drives up costs for other industries as they are forced to compete with the oil and gas industry for skilled workers.

6. Impacts on manufacturing

The unconventional gas industry hurts the manufacturing industry, mostly because they compete for skilled labour. Economic modelling by the Queensland unconventional gas company Arrow LNG for its Economic Imact Assessment found that its project would displace $441.5 million worth of manufacturing output and 1,000 manufacturing jobs in Queensland.[18]

Arrow LNG is just one of the four large unconventional gas projects in Queensland. The full employment impacts of this single project can be seen in Figure 11 below.

While the modelling suggests the project would a create a considerable number of short term construction jobs, these jobs come at the expense of long term jobs in other sectors, particularly manufacturing.

Once extinguished, manufacturing activity is difficult to rebuild. Plants and equipment require a large upfront investment, but only deliver returns over the long term. If a region is likely to experience further disruption from large resource projects, investors are unlikely to have confidence in manufacturing.

Figure 11: Average Annual Impact on Employment by Industry in Queensland of Arrow LNG project.

Industry	Change in Employment (FTEs)			
	2013-14 to 2016-17 (Phase 1 Construction)	2018-19 to 2021-22 (Phase 1 Steady State Operation)	2022-23 to 2024-25 (Phase 2 Construction) [(a)]	2026-27 to 2029-30 (Phase 2 Steady State Operation) [(a)]
Queensland				
Agriculture	-59	-24	-66	-42
Mining	-65	-28	-69	-50
Manufacturing	-1,089	-25	-804	-200
Electricity and water	-10	25	39	55
Construction	1,833	127	1,325	257
Trade	221	58	255	130
Transport and storage	-246	-27	-186	-37
Business, finance and insurance services	-132	83	119	166
Public administration, defence, health and education	29	-6	-45	-19
Recreation and other services	22	-4	1	-8
Ownership of dwellings	6	0	3	0
Total Change in Employment in Queensland	**511**	**180**	**571**	**251**

Note: (a) It should be noted that operation of Phase 1 (trains 1 and 2) is ongoing during these time periods.
Source: Prime Research (unpublished).

Source: AEC Group (2011) Arrow LNG Economic Impact Assessment, table 5.3 p.43

[18] Grudnoff, M. (2015) *An analysis of the economic impacts of Arrow Energy's Gladstone LNG Plant*.

As well as higher labour costs, unconventional gas projects have – perversely – increased the cost of gas for manufacturers.

In their Economic Impact Assessment of 2010 GLNG noted that “a relatively mild increase in gas prices associated with the QCLNG Project may occur in the eastern Australian market”.[19]

In fact, linking Australian domestic gas prices to higher Asian prices has more than doubled the wholesale gas price.

The recent collapse in the oil price, and subsequently Asian “oil linked” gas prices, has not caused a commensurate reduction in the price of gas being offered to manufacturers. This has led to claims of “cartel like behaviour”. [20] The ACCC’s ongoing inquiry into the East Coast gas market is investigating “the existence of, or potential for, anti-competitive behaviour and the impact of such behaviour on purchasers of gas”.[21]

Economic modeling by Deloitte Access Consulting shows that east coast gas price rises caused by unconventional gas exports have created a $81 billion windfall for the gas industry (mostly global oil and gas majors), but will cost the manufacturing industry $118 billion.[22]

Figure 12: Industry output impacts for Australia as a result of gas price increases.

Table i: Industry output impacts for Australia for the years 2015, 2018 and 2021 and cumulative Net Present Value (NPV) of output impacts over 2014 - 2021

	Value of difference from baseline			% difference			NPV
	2015	2018	2021	2015	2018	2021	Cumulative impact over 2014-2021

[19] GLNG Economic Impact Statement, volume 8 chapter 10, p 12.

[20] West, M. (October 2015) “East coast gas market has all the hallmarks of a cartel”. Accessed 11 November 2015, <http://www.smh.com.au/business/comment-and-analysis/east-coast-gas-market-has-all-the-hallmarks-of-a-cartel-20151011-gk6b4i.html>.

[21] ACCC Project Overview, *East Coast Gas Inquiry*. Accessed 11 November 2015, <https://www.accc.gov.au/regulated-infrastructure/energy/east-coast-gas-inquiry-2015>.

[22] Deloitte Access Economics (2014) *Gas market transformations–Economic consequences for the manufacturing sector* Table 1, p 3.

SKM scenario							
Output ($ million)							
Manufacturing	-23,199	-22,259	-30,386	-3.97	-3.48	-4.38	-118,069
Gas	8,922	17,672	24,225	47.81	65.63	57.07	80,746
Mining	-7,226	-6,031	-9,679	-3.55	-2.69	-3.96	-33,804
Agriculture	-1,110	-798	-1,430	-1.98	-1.32	-2.21	-4,705
Electricity and Water	-1,962	-1,989	-2,204	-3.36	-3.09	-3.12	-10,269
Construction and Trade	18,049	2,443	13,265	2.80	0.34	1.69	38,519
Transport	-2,328	-1,988	-3,288	-1.68	-1.31	-2.00	-11,044
Commercial & Services	3,015	-897	649	0.26	-0.07	0.05	1,695

Source: Deloitte Access Economics

Note: The discount rate of 7% was used to calculate the NPV figure.

Source: Deloitte Access Economics (2014)

No amount of additional gas extraction in the Northern Territory or elsewhere will reduce gas prices in Australia as all gas will now go to the Asian market. As the NSW Independent Pricing and Regulatory Tribunal (IPART) put it:

> The increase in regulated retail gas prices 2014/15 reflects increased wholesale gas costs as eastern Australia becomes part of a single global market for commodity gas, as well as increasing network charges.[23]

[23] Inquiry into the supply and cost of gas liquid fuels in NSW, IPART 2014. Accessed 10 July 2015, <http://www.parliament.nsw.gov.au/prod/parlment/committee.nsf/0/efb3f0c1908f7b21ca257dc7000 5b1b 2/$FILE/0023%20-%20IPART.pdf>

7. Big numbers, small benefits

Gas companies often cite the amount of money they invest or the value of the gas they sell as proof of the economic benefits of their projects.

However these numbers say little about benefits for Australians if the money invested in a project is spent on equipment from overseas, profits flow to foreign investors and the companies pay little tax or royalties.

The oil and gas industry in Australia is over 80% foreign owned,[24] which means that over 80% of the profits go directly off shore. It imports almost all its equipment and pays very low rates of tax. The theoretical company tax rate in Australia is 30%. All industries are able to claim exemptions and the average effective company tax rate of all industries in 2011/12 was 17.6%. That year the oil and gas industry in Australia paid an effective company tax rate of 5.4%.[25]

The Queensland LNG projects were approved without an estimate of royalty payments to the state government.

As the Reserve Bank of Australia concluded, while Australian production of LNG is expected to ramp up substantially over the next few years:

> The effect on Australian living standards will be less noticeable than this given the low employment intensity of LNG production, the high level of foreign ownership of the LNG industry and, in the near term, the use of deductions on taxation payments. [26]

The big numbers for capital value or change in GDP tell us little about the benefit of gas exports to the wider Australian economy and community. As the Reserve Bank of Australia notes, these benefits are likely to be smaller.

[24] Calculations by The Australia Institute based on published 2P reserves and production.
[25] Taxation statistics 2011–12, Table 4: Company tax, Selected items by industry, ABS 81550DO002_201112 Australian Industry.
[26] Cassidy, N. and Kosev, M. (2015) Australia and the Global LNG Market, RBA.

8. The Industrial footprint of shale gas

One important way that unconventional gas development differs from other types of resource development is that it covers far greater areas. Mines are generally highly concentrated with relatively small footprints, while unconventional gas fields often cover tens of thousands of square kilometers with an industrial grid of wells, pipelines, access roads, compressor stations and water treatment plants.

The most mature shale gas field in the US, the Barnett Shale has an average of 1.15 wells per square kilometer, but is as high as 6 wells per square kilometer due to "infill drilling" needed to extract gas as fields deplete.[27]

Every shale gas well needs to be fracked multiple times. Every frack requires 11-34 million litres of water[28] equating to 360-11,000 truckloads and "80-300 tonnes of industrial chemicals [29]. This is potentially an enormous increase in truck mvements on the Territory's roads and will inevitable impact other road users.

Pennsylvania in the United States has a mature shale gas industry. A gas industry study last year in Pennsylvania found that more than 6% of gas wells leaked, and up to 75% of wells could have some form of integrity failure. [30] In Pennsylvania more than 240 private drinking water wells have been contaminated or have dried up as the result of drilling and fracking operations over a seven-year period[31]

---

[27] Shale Gas Information Platform SHIP. GFZ http://www.shale-gas-information-platform.org/categories/operations/the-basics.html Accessed 10/11/15

[28] UNEP Global Environmental Alert Service: Gas Fracking: Can we safely squeeze the rocks?

[29] Hazen and Sawyer, December 22, 2009. Impact Assessment of Natural Gas Production in the New York City Water Supply Watershed.

[30] Davies, R. J., Almond, S., Ward, R. S., Jackson, R. B., Adams, C., Worrall, F., ... Whitehead, M. A. (2014). Oil and gas wells and their integrity: Implications for shale and unconventional resource exploitation. *Marine and Petroleum Geology, 56*, 239-254. doi: 10.1016/j.marpetgeo.2014.03.001

[31] Concerned Health Professionals of New York & Physicians for Social Responsibility. (2015, October 14). Compendium of scientific, medical, and media findings demonstrating risks and harms of fracking (unconventional gas and oil extraction) (3rd ed.). http://concernedhealthny.org/compendium/

Conclusion

Gas companies routinely exaggerate the economic and jobs benefits of their projects. Policy makers often accept these claims unquestioningly.

The Northern Territory is fortunate to have the Queensland unconventional gas experiment to reflect upon. The Queensland experience is that most of the economic benefits do not materialise, and serious collateral damage is done to existing industries and local communities.

If policy makers in the Northern Territory naively accept the economic claims of speculative gas companies and use taxpayer money to support this industry, Territorians will live the consequences for decades to come.