DELAWARE RIVERKEEPER NETWORK™

March 30, 2016

Pennsylvania Department of Environmental Protection

Submitted as e-comment at: http://www.ahs.dep.pa.gov/eComment/Comments.aspx

Re: DRAFT 2015 Climate Change Action Plan Update

Delaware Riverkeeper Network (DRN) submits these comments on the DRAFT Climate Change Action Plan Update prepared by the Pennsylvania Department of Environmental Protection (DEP) pursuant to the Pennsylvania Climate Change Act (Act 70).

DRN submits the five attached documents in support of our position that DEP's stated target of a 30% reduction in greenhouse gas emissions (GHG) by 2020 is neither sufficient if Pennsylvania is to make meaningful progress towards reducing the Commonwealth's contribution to global climate change nor is it achievable if natural gas development, including extraction, storage, transmission and end use, continues in Pennsylvania.

We agree that it is clear that we need to reduce GHG emissions but we do not agree that it is acceptable or possible to reach a goal of reduction by following the proposed climate change action plan. The attached documents and peer-reviewed papers explain that the Commonwealth must get off fossil fuels as quickly as possible, that no new GHG emitting power plants can be justified in the Commonwealth and the use of fossil fuels in all energy sectors must be replaced by energy efficient renewable energy sources to provide an effective climate change action plan.

The shale gas being developed now here in Pennsylvania emits methane, a GHG that is 100 times greater in absorbing heat than carbon dioxide and 86 times greater when averaged over a 20 year time frame. Globally, meeting the COP 21 Paris goal to limit warming to below 2degree C requires zero GHG emissions from power generation after 2017. Here in Pennsylvania, the Commonwealth must not attempt to incentivize natural gas (or any fossil fuel) development by the exemption of new plants from its Draft Clean Power Plan that is currently under development. Coal, oil, and natural gas all need to be left in the ground.

DRN advocates that Pennsylvania adopt a much more aggressive plan that does not include fossil fuel development and relies on energy efficiency, conservation, and renewable energy sources

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that can be sustained over the long term. DRN supports the development of a Climate Change Action Plan that adopts a hierarchy of goals that places clean air, water, and a healthy environment for communities and workers, including healthy and biologically diverse habitats and ecosystems, as the top priority based on the tenants of the Environmental Rights Amendment – Article 1, Section 27 – of the Pennsylvania Constitution.

> Pennsylvania Constitution Article 1, Section 27:
>
> “The people have a right to clean air, pure water, and to the preservation of the natural, scenic, historic and esthetic values of the environment. Pennsylvania’s public natural resources are the common property of all the people, including generations yet to come. As trustee of these resources, the Commonwealth shall conserve and maintain them for the benefit of all the people.”

The attached documents include:

1. Paper entitled “Sustainable Energy Options” excerpted from the writings of Mark Z. Jacobsen. The paper is a chapter from “Unsafe and Unsustainable” published by Delaware Riverkeeper Network, 2014.

2. Testimony of Robert W. Howarth, Ph.D., Earth Systems Scientist, David R. Atkinson Professor of Ecology and Environmental Biology, Cornell University to Pennsylvania House Democratic Policy Committee, March 21, 2016.

3. Testimony of Mark Szybist, Esq., Senior Program Advocate, Natural Resources Defense Council, to Pennsylvania House Democratic Policy Committee March 21, 2016.

4. Testimony of Donald A. Brown, Scholar in Residence and Professor, Widener University Commonwealth Law School to Pennsylvania House Democratic Policy Committee, March 21, 2016.

5. Pfeiffer A et al. The ‘2degree capital stock’ for electricity generation: Committed cumulative carbon emission from the electricity generation sector and the transition to a green economy. Appl Energy (2016). http://dx.doi.org/10.1016/j.apenergy.2016.02.093

Respectfully submitted,

Maya K. van Rossum	Tracy Carluccio
the Delaware Riverkeeper	Deputy Director

Cornell University

Statement of Robert W. Howarth, Ph.D.

House Democratic Policy Committee Hearing
"Should Pennsylvania Incentivize Natural Gas?"

March 21, 2016

Thank you for the opportunity to address you today. My name is Robert Howarth. I am an Earth systems scientist with a Ph.D. jointly from MIT and the Woods Hole Oceanographic Institution. I have been a tenured member of the faculty of Cornell University since 1985 and have held an endowed position as the *David R. Atkinson Professor of Ecology & Environmental Biology* at Cornell since 1993. I also serve as an Adjunct Senior Scientist at the Ecosystems Center in Woods Hole, MA. I am the Editor in Chief of the academic journal *Limnology & Oceanography* and previously served as Editor in Chief of the academic journal *Biogeochemistry* for over 20 years. I have published more than 200 peer-reviewed research articles and am the editor or author of 8 scholarly books.

I have conducted research and taught on several aspects of global change for over 35 years. In 2011, I published the first ever peer-reviewed analysis of the greenhouse gas footprint of shale gas. Since then, I have published an additional 6 peer-reviewed papers as well as a background report for the US Climate Change assessment on the topic of greenhouse gas emissions from the development and use of shale gas. I also have published 2 peer-reviewed articles laying out plans for the states of New York and California to become free of all fossil fuel use. I served as a delegate to the United Nations COP21 negotiations on climate change in Paris this past December, and while there participated in several discussions on the role of methane and shale gas in climate change. My most recent peer-reviewed publication on the role of methane emissions in the greenhouse gas footprint of shale gas (Howarth 2015), published in October of last year, is appended at the end of this testimony. The statements and conclusions I draw here are all well documented in that paper.

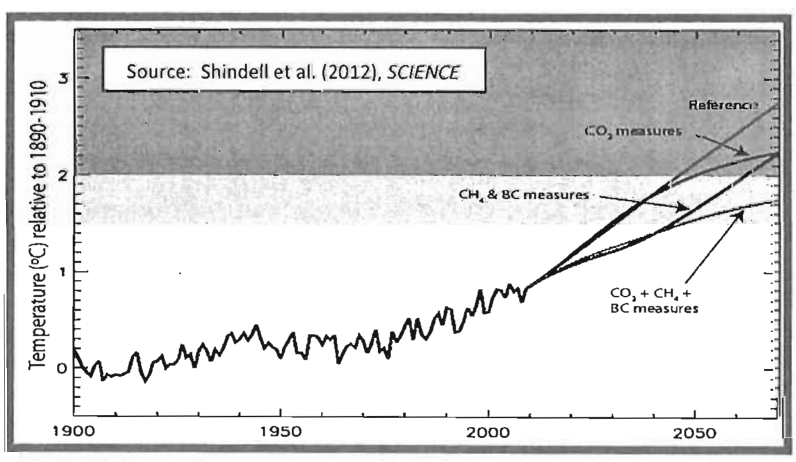
In the past, industry as well as many politicians promoted natural gas, including shale gas, as a "bridge fuel" that would allow society to continue to use fossil fuels for the next few decades while reducing carbon dioxide emissions. While less carbon dioxide is produced while burning natural gas than is true for coal for a given amount of energy, methane emissions from the use of natural gas are far higher than from coal. Methane is a potent greenhouse gas, one that is more than 100 times as effective as carbon dioxide in trapping heat in the atmosphere for the decade or so following emission

when both gases remain in the atmosphere. Using the best available evidence on rates of methane emissions, shale gas is seen to have a greenhouse gas footprint that is 2.5-fold greater than that of coal when compared over a 20-year averaged period following the burning of the two fuels. Conventional natural gas also has a larger footprint than does coal, although only slightly so.

Before the shale gas revolution began in earnest in 2009, the scientific literature ignored methane emissions from this fuel. We first suggested in our 2011 paper that methane emissions from shale gas may be far larger than from conventional natural gas. The available evidence at that time was limited, and so one of our major conclusions was to point for the need for better studies. Our suggestion of high methane emissions was hotly contested by industry and by some academics, but extensive subsequent research has indicated that indeed the methane emissions are far higher than for shale gas. This is particularly evident in the study by Schneising and colleagues published in 2014 that used satellite data, comparing methane levels in the atmosphere for a few years before the shale gas revolution (2006-2008) with levels in the first few years after heavy shale gas and oil development began (200-2011). During this time, the methane concentration in the atmosphere increased globally, and the satellite data indicate the shale gas and shale oil plays of the United States are the likely source of most if not all of this increased methane.

These methane emissions from shale gas have had a major impact on the greenhouse gas inventory of the United States. Beginning in 2007, carbon dioxide emissions from fossil fuel use in the US fell, in part due to recession but also due to some switching of natural gas for coal in electricity generation. However, as shale gas became an increasingly large percentage of natural gas production, methane emissions began to rise sharply. As a result, the total greenhouse gas inventory of the US has been rising rapidly since 2008, and in fact this has been the most rapid rate of increase in greenhouse gas emissions seen in many decades. Clearly natural gas is no bridge fuel.

Note that my analysis differs from the position of the US EPA in their inventory reporting, for two reasons: 1) the EPA continues to underestimate the extent of methane emissions, as noted by a growing number of critics including the inspector general of the US EPA; and 2) the EPA continues to use outdated science to compare the influence of methane and carbon dioxide, despite the guidance to the contrary given by the Inter-Governmental Panel on Climate Change in their most recent synthesis report from 2013. For more discussion on these problems with the EPA analysis, please refer to my 2015 paper, appended below.



I would like to provide one update on the importance of methane to global warming based on events since my most recent paper was published 6 months ago: in Paris 3 months ago, the 195 nations of the world came together and agreed to keep the temperature of the Earth well below 2° C compared to the pre-industrial

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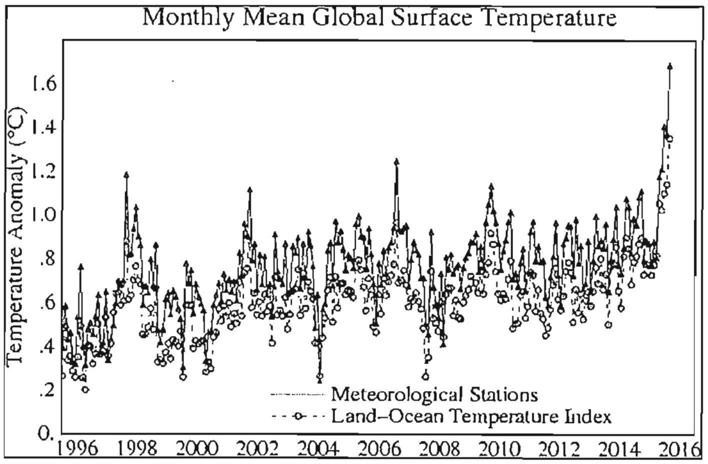

Global warming reaches all-time new high in February 2016. Source: NASA Goddard Space Sciences Institute, down-loaded March 13, 2016.

Unfortunately, the very latest evidence shows that the planet is warming even more quickly than model predictions. Last month, the temperature of the Earth spiked above 1.6° C, according to data from the NASA Goddard Space Institute. The temperature increase from a year ago is the fastest ever observed. This high temperature for February 2016 is driven both by *el nino* and by human-caused global warming, and we can expect the temperature to decrease some over the coming months. Nonetheless, the accelerating upward general trend of global warming is alarming.

Given the role of methane in global warming, and the large emissions of unburned methane to the atmosphere as shale gas is developed, I strongly recommend that society more as quickly as possible away from using shale gas a fuel. We have alternatives: embrace wind, solar, and highly efficient 21st Century technologies for using electricity for transportation and for heating. I urge that the House Democratic Policy Committee show leadership and help move the Commonwealth of Pennsylvania to this alternative energy future.

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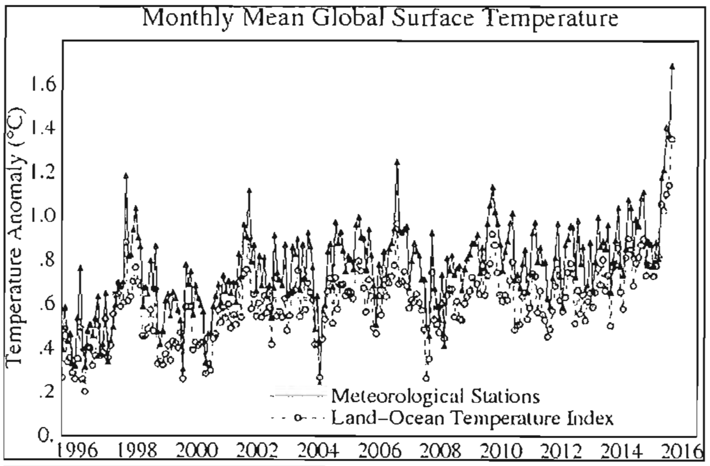

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REVIEW

Methane emissions and climatic warming risk from hydraulic fracturing and shale gas development: implications for policy

Robert W Howarth

Department of Ecology and Environmental Biology, Cornell University, Ithaca, NY, USA

Abstract: Over the past decade, shale gas production has increased from negligible to providing >40% of national gas and 14% of all fossil fuel energy in the USA in 2013. This shale gas is often promoted as a bridge fuel that allows society to continue to use fossil fuels while reducing carbon emissions since less carbon dioxide is emitted from natural gas (including shale gas) than from coal and oil per unit of heat energy. Indeed, carbon dioxide emissions from fossil fuel use in the USA declined to some extent between 2009 and 2013, mostly due to economic recession but in part due to replacement of coal by natural gas. However, significant quantities of methane are emitted into the atmosphere from shale gas development: an estimated 12% of total production considered over the full life cycle from well to delivery to consumers, based on recent satellite data. Methane is an incredibly powerful greenhouse gas that is >100-fold greater in absorbing heat than carbon dioxide, while both gases are in the atmosphere and 86-fold greater when averaged over a 20-year period following emission. When methane emissions are included, the greenhouse gas footprint of shale gas is significantly larger than that of conventional natural gas, coal, and oil. Because of the increase in shale gas development over recent years, the total greenhouse gas emissions from fossil fuel use in the USA rose between 2009 and 2013, despite the decrease in carbon dioxide emissions. Given the projections for continued expansion of shale gas production, this trend of increasing greenhouse gas emissions from fossil fuels is predicted to continue through 2040.

Keywords: shale gas, natural gas, methane, greenhouse gases, global warming, bridge fuel

Video abstract

Point your SmartPhone at the code above. If you have a QR code reader the video abstract will appear. Or use: http://youtu.be/0U6R8EIzew

Introduction

Shale gas is natural gas tightly held in shale formations, and as for conventional natural gas, shale gas is composed largely of methane. The difference between shale gas and conventional natural gas is the mode of extraction. Shale gas cannot be obtained commercially using conventional techniques and has entered the market only recently as industry has used two relatively new technologies to extract it: high-precision horizontal drilling with high-volume hydraulic fracturing. Over the past decade, shale gas development in the USA has increased rapidly, a trend that both the Energy Information Agency (EIA) of the US Department of Energy and the industry expect to continue[1–3] (Figure 1). To date, almost all shale gas production in the world has occurred in the USA, a condition likely to continue for at least another decade.[2] The EIA projections for future growth in shale gas development may well be too rosy because both the expense of developing shale gas and the pattern of production from a shale gas well have proven to differ dramatically from that seen in conventional gas wells, with very rapid declines over the first year or two.[4] An independent assessment concludes that

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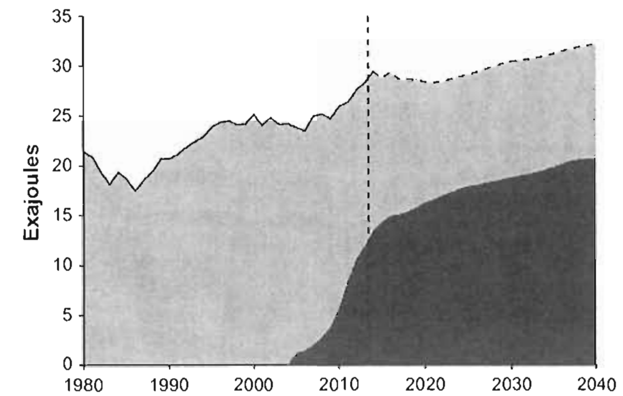

Figure 1 Natural gas production in the USA from 1980 to 2013 and future natural gas production until 2040 as predicted by the US Department of Energy in the *Annual Energy Outlook 2015*.[1] Conventional gas is indicated in yellow, shale gas in red.

shale gas production in the USA is likely to underperform the EIA estimates by almost 40% between now and 2040.[5] However, all these estimates are highly uncertain. If the EIA projections prove true, what might some of the environmental and public health consequences be?

Since shale gas development is a recent phenomenon, scientific investigations on its environmental and public health consequences are also quite new, with the first peer-reviewed studies published only in 2011.[6,7] Nonetheless, the literature has quickly grown, and evidence is accumulating of many adverse effects, including surface and groundwater contamination,[8] degraded air quality,[9,10] increased release of greenhouse gases,[11,12] increased frequency of earthquakes,[13] and evidence of harm to the health of humans and domestic animals, including farm livestock.[7,14–18]

The natural gas industry often points out that hydraulic fracturing has been in use for >60 years, implying that there is little new about shale gas development.[19] The scale of hydraulic fracturing used to develop shale gas, however, is far greater than the fracturing employed in previous decades for conventional gas, with two orders of magnitude increase in the volume of water and chemicals used from the hydraulic fracturing and even proportionally greater return of fracturing wastes to the surface.[6] Further, the use of high-volume hydraulic fracturing with high-precision directional drilling to develop shale gas leads to an intensity of development not generally seen with conventional natural gas and to the redevelopment of regions where conventional gas has largely played out, which may intensify some effects such as air emissions due to interactions with old wells and formations.[20] The appropriate focus when considering the environmental and public health effects of shale gas development is on the entire enterprise and use of the gas and not merely on the process of hydraulic fracturing.

This paper focuses on the role of methane emissions in determining the greenhouse gas footprint of shale gas. Natural gas, including shale gas, is often promoted as a bridge fuel that will allow society to continue to use fossil fuels over the coming decades while reducing carbon emissions. This was highlighted, for example, by President Obama in his State of the Union speech in January 2014.[21] For a given unit of energy consumed, the emissions of carbon dioxide from natural gas are substantially lower than from oil or coal,[11,22] which is the basis for the bridge fuel concept. However, natural gas is composed mostly of methane, a greenhouse gas that on a mass-to-mass basis is >100 times more powerful than carbon dioxide as an agent of global warming for the time when both gases persist in the atmosphere.[23] Consequently, even small releases of methane to the atmosphere from the development and use of shale gas can greatly influence the greenhouse gas footprint of shale gas.

How much methane is emitted?

My coauthors and I published the first peer-reviewed assessment of methane emissions from shale gas development in 2011.[11] We concluded that 3.8% (±2.2%) of the total lifetime production of methane from a conventional gas well is emitted into the atmosphere, considering the full life cycle from well to final consumer.[11] The data available for estimating emissions from shale gas were more scarce and more poorly documented at that time, but we estimated that the full life cycle emissions of shale gas were ~1.5-fold higher than that of conventional natural gas, or 5.8% (±2.2%).[11] We attributed the higher emissions to venting of gas during the flowback period following high-volume hydraulic fracturing, although a subsequent study identified other sources as well, such as drilling through strata previously developed for coal and conventional natural gas.[20] For both conventional gas and shale gas, we estimated the "downstream" emissions associated with storing gas and delivering it to market to be 2.5% (±1.1%), so our estimates for "upstream" emissions at the well site and from gas processing averaged 1.3% for conventional natural gas and 3.3% for shale gas.[11,12]

Through 2010, the US Environmental Protection Agency (EPA) continued to estimate emissions for conventional natural gas as 1.1%, with 0.9% of this from downstream emissions and 0.2% from upstream emissions, based on a joint EPA and industry study from 1996, as I discuss elsewhere.[12]

They did not separately consider shale gas emissions. Soon after our paper was published in 2011, the EPA released new estimates that were very similar to ours in terms of upstream emissions: 1.6% for conventional natural gas and 3.0% for shale gas.[12] They kept their downstream emission estimates at 0.9%, yielding full life cycle emissions of 2.5% and 3.9%, respectively, for conventional gas and shale gas. EPA subsequently reduced their estimates for upstream emissions, cutting them approximately in half, relying on a non-peer-reviewed industry report[24] asserting that the 2011 estimates had been too high.[12,25] This yielded a full life cycle emission estimate for all natural gas in the USA, considering the contributions from both conventional and shale gas as of 2009, of 1.8%.[12] The inspector general of the EPA has called for improvements in the agency's approach in estimating emissions,[26] at least in part because of the 2013 decision to lower emission estimates.[12,25]

In our original 2011 paper, we called for new and better studies of methane emissions from the natural gas industry,[11] and in fact, many studies have been published in the subsequent 4 years. In 2014, I published a review of the new studies that had come out through February 2014.[12] One of these studies evaluated a large set of data from monitoring stations across the USA for the period 2007–2008, before the large increase in shale gas production, and concluded that the EPA estimate of 1.8% emission was clearly too low by a factor of at least 2 and that full life cycle emissions from conventional natural gas must be ≥3.6% on average across the USA.[27] Other, shorter term studies evaluated upstream emissions from shale gas and other unconventional gas development (ie, tight sands), with two finding high emissions (4%–9%)[25,28] and one published by Allen et al finding low emissions (0.4%).[29] In a summary published in early 2014, Brandt et al concluded that emissions from the natural gas industry, including both conventional gas and shale gas, could best be characterized as averaging 5.4% (±1.8%) for the full life cycle from well to consumer.[30] I accepted that conclusion and presented it as the best value in my 2014 review.[12]

Further thought and subsequent studies published since February 2014 have led me to reconsider. I now believe that emissions from conventional natural gas are somewhat <5.4%, based on the ^{14}C content of atmospheric methane globally, and emissions from shale gas are likely substantially more, based on global trends observed from satellite data and new evidence that the 2013 report by Allen et al of only 0.4% emissions[29] is likely to be flawed.

^{14}C content of methane and emissions from conventional natural gas

The ^{14}C radiocarbon content of methane in the planet's atmosphere provides a constraint on the emission rate from conventional natural gas systems. On average during the years 2000–2005, 30% of atmospheric methane was ^{14}C "dead", indicating that it came from fossil sources.[31,32] During this time period, the total global flux of methane to the atmosphere was probably in the range of 548 (±22) Tg CH_4 per year.[33] Therefore, the flux from fossil sources, 30% of the total flux, would have been ~165 Tg CH_4 per year. These fossil sources include fluxes associated with coal, oil, and natural gas development as well as natural seeps. Using global production data for coal and oil[34] and well-accepted methane emission factors for these two fuels as described elsewhere,[11] I estimate the combined methane emissions from oil and coal as ~50 Tg CH_4 per year. Using the 5.4% emission rate and global natural gas production estimates[34] for the years 2000–2005 yields a methane emission of 130 Tg CH_4 per year from the natural gas industry or 180 Tg CH_4 per year from all fossil fuels. This is too high compared to the ^{14}C constraint, suggesting that an emission rate of 5.4% for conventional gas is too high, even if natural seeps are negligible, as assumed by the Intergovernmental Panel on Climate Change (IPCC) in 2007 in their fourth assessment report.[35] Flux estimates from natural seeps are poorly constrained, but these natural emissions may be as great as 50 Tg CH_4 per year or higher.[31] If we instead use the mean emission factor from our 2011 paper for conventional natural gas of 3.8%,[11] the global flux from natural gas emissions is estimated as 91 Tg CH_4 per year, giving an emission flux from all fossil fuels of ~140 Tg CH_4 per year and an estimate of emissions from natural seeps of 15 Tg CH_4 per year. This combination is plausible, if uncertain, and the 3.8% factor agrees well with the robust conclusion from Miller et al that emissions from conventional natural gas systems in the USA, from before the shale gas boom, must have been at least 3.6% of production.[27]

How high are methane emissions from shale gas?

A paper published by Schneising et al in the fall of 2014 used satellite data to assess global and regional trends in atmospheric methane between 2003 and 2012.[36] Methane concentrations rose dramatically in the northern hemisphere, particularly after 2008. In a detailed comparison across the

USA for the time periods 2006–2008 (before there was much shale gas or shale oil development) and 2009–2011 (after shale gas and oil production began in earnest), atmospheric methane concentrations rose dramatically in many of the major shale-producing regions. By evaluating trends in drilling and hydraulic fracturing activity, Schneising et al estimated methane emission rates of 9.5% (±7%) in terms of energy content during the 2009–2011 period for the two large shale regions – the Eagle Ford in Texas and the Bakken in North Dakota – where they felt most comfortable in estimating emissions.[36] They reported similar methane emissions for the Marcellus shale, but with much greater uncertainty in the analysis of the satellite data because of sparser spacing of wells, the mountainous terrain, and the proximity of the region to the Great Lakes. For the Bakken, shale oil production was far greater than gas production during this time period,[37] and the methane emissions may have been more associated with the oil production. However, natural gas was the dominant form of shale energy produced in the Eagle Ford formation between 2009 and 2011, contributing 75% of all shale energy with oil contributing 25%.[37] For the Marcellus shale, virtually all shale energy production through 2011 came from shale gas and not oil.[37] Therefore, it seems reasonable to attribute a methane emission rate of ~9.5% to shale gas development in the Eagle Ford and Marcellus formations.

The satellite methane emission estimate is largely for upstream emissions and does not fully account for downstream emissions during storage and delivery of gas to customers, which may on average add another 2.5% of methane emission.[11,12,22] The conclusion is that shale gas development during the 2009–2011 period, on a full life cycle basis including storage and delivery to consumers, may have on average emitted 12% of the methane produced. This is more than twice what we had estimated for shale gas in our 2011 analysis,[11] but the satellite-based estimate is based on more robust data and integrates across a period of 2 years. These shale gas emissions already may have a globally observable effect on methane in the atmosphere.[36]

The satellite-based estimate is ~20-fold greater than the estimate presented by Allen et al,[29] a study that worked closely with industry to measure emissions from various component processes of shale gas development. In my 2014 review, I suggested that the study by Allen et al may represent a best-case scenario for low emissions, given that measurements were made only at sites where industry allowed.[12] Since then, two papers published in 2015 have indicated that in fact the data in the Allen et al's paper may be flawed. Allen et al used a high-flow analyzer that employs two independent sensors, switching between a catalytic oxidation detector when methane levels are low and a thermal conductivity detector when methane concentrations are greater. Howard et al noted that the high-flow analyzer is prone to underestimating methane fluxes when switching between detectors.[38] A follow-up paper by Howard et al carefully evaluated the use of a high-flow analyzer by Allen et al and concluded that "the data reported by Allen et al. (2013) suggest their study was plagued by such sensor failure", and as a result "their study appears to have systematically underestimated emissions."[39] The sensor failure issue may well have affected other data reported by industry to the EPA and used by the EPA in their assessment of methane emissions, leading to serious underestimation.[38,39]

Several other recent studies have estimated upstream methane emissions from shale gas and other unconventional natural gas development (ie, from tight-sand formations) using more robust and more integrated measurement techniques such as airplane flyovers, but still with highly variable results. Estimates were ~30% greater than the satellite-derived data for one gas field,[40] were comparable in two other cases,[20,25] were only about half as much for two sets of measurements in another gas field,[28,41] and were substantially less in three other cases.[40] Peischl et al have suggested that higher emissions are associated with wet-gas fields and lower emissions with dry-gas fields.[40] Alternatively, the variation in emissions may simply reflect variance in space and/or in time: many of these studies were quite short in duration, for example, based on measurements made during airplane flyovers of just 1–2 days.[20,40] It is also important to note that these emission estimates are given as percentages of the gas production rates. The activity of the natural gas industry and rates of production in various gas fields are quite variable in time, and some of the differences in percentage emission rates may reflect this variability. For instance, Caulton et al reported high emission rates in the southwestern Pennsylvania portion of the Marcellus shale based on a June 2012 flyover,[20] while Peischl et al reported a very low percentage of emission rate in the northeastern Pennsylvania portion of the Marcellus shale from a July 2013 flyover.[40] Between these two flights, gas drilling activity for shale gas fell by 64% due to low prices for gas,[42] yet shale gas production remained high based on prior drilling and hydraulic fracturing.[1] If methane emission is more related to drilling and hydraulic fracturing activity than to production, these rapid changes in activity may explain at least part of the differences between the two estimates for Marcellus shale.

I therefore conclude that the satellite data[36] provide the most robust estimates for upstream methane emissions from shale gas operations to date.

Is natural gas a bridge fuel?

Natural gas is widely promoted as a bridge fuel, a source of energy that allows society to continue to use fossil fuels while reducing greenhouse gas emissions over the next 2 decades or so, until renewable energy sources can more fully come on line. Our 2011 paper challenged that view because of methane emissions from natural gas, although we tempered our conclusion because of the uncertainty in methane emissions from shale gas development.[11] We also observed that the time frame over which one compares the consequences of emissions of carbon dioxide and methane is important in determining the overall greenhouse gas footprint of natural gas. While many studies have made this comparison only by averaging the radiative forcing of the two gases over a time of 100 years following emission, we compared on a 20-year timescale as well, following the lead of Hayhoe et al[22] and Lelieveld et al.[43] Methane has a residence time in the atmosphere of only 12 years,[23,33] while the influence of carbon dioxide emissions persists in the atmosphere for many hundreds of years or longer.[23] While both gases are in the atmosphere, the greenhouse warming effects of methane are >100-fold greater than for carbon dioxide on a mass-to-mass basis.[23] When compared on a 100-year average time after emission, the emitted methane is largely absent from the atmosphere for almost 90% of that time, which greatly underplays the importance of methane while it is in the atmosphere.

Our 2011 paper was criticized for comparing the consequences of methane and carbon dioxide over a 20-year period in addition to the 100-year period, with some authors stating that only a 100-year period should be used under the guidance of the IPCC.[44,45] This was never the case, and in the fourth synthesis report in 2007, the IPCC presented analyses based on both 20- and 100-year time periods.[35] Further, in the fifth synthesis report in 2013, the IPCC explicitly weighed in on this controversy, stating that "there is no scientific argument for selecting 100 years compared with other choices", and "the choice of time horizon [...] depends on the relative weight assigned to the effects at different times".[23]

So what is the best choice of timescale? Given current emissions of greenhouse gases, the Earth is predicted to warm by 1.5°C above the preindustrial baseline within the next 15 years and by 2°C within the next 35 years.[46,47] Not only will the damage caused by global warming increase markedly but also at these temperatures, the risk of fundamentally altering the climate system of the planet becomes much greater.[48,49] Further, reducing emissions of carbon dioxide will do little if anything to slow the rate of global warming over these decadal time periods.[47] On the other hand, reducing emissions of methane has an immediate effect of slowing the rate of global warming.[47] For these reasons, comparing the global warming consequences of methane and carbon dioxide over relatively short time periods is critical. The use of a global warming potential (GWP) estimate for the 20-year time period from the IPCC fifth assessment report provides a convenient approach for doing so.[23] This GWP value of 86 is the relative radiative forcing for methane compared to that of carbon dioxide, averaged over 20 years, for two equal masses of the gases emitted into the atmosphere today.

Figure 2 compares the greenhouse gas footprint of shale gas with that of conventional natural gas, oil, and coal. Methane emissions of shale gas are derived from the satellite-based estimates of Schneising et al[36] with an additional 2.5% emission rate assumed from downstream transport, storage, and distribution systems.[11,12,22] Methane emissions for the other fuels are those used in our 2011 paper, which is 3.8% (±2.2%) for conventional natural gas.[11] Methane emissions are converted to carbon dioxide equivalents using the 20-year GWP value of 86 from the IPCC assessment.[23] While for a

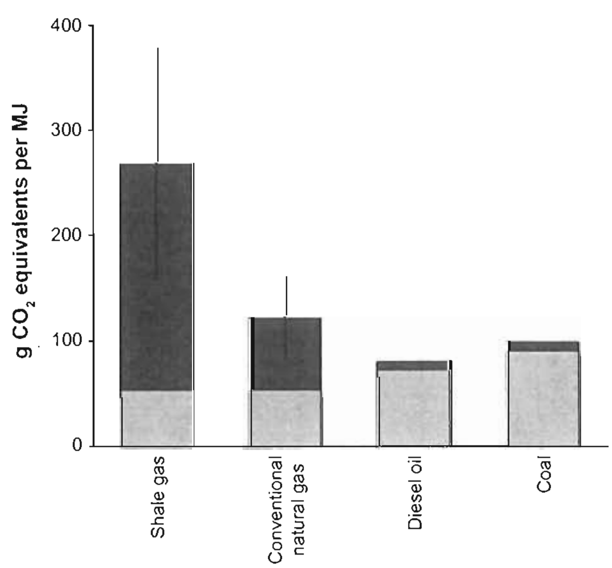

Figure 2 The greenhouse gas footprints of shale gas, conventional natural gas, oil, and coal expressed as g CO_2 equivalents per MJ of heat produced.

Notes: Yellow indicates direct and indirect emissions of carbon dioxide. Red indicates methane emissions expressed as CO_2 equivalents using a global warming potential of 86. Vertical lines for shale gas and conventional natural gas indicate the range of likely methane emissions. Emissions for carbon dioxide for all fuels and for methane from conventional natural gas, oil, and coal are as in Howarth et al.[11] Mean methane emission estimate of shale gas is taken as 12% based on Schneising et al[36] as discussed in the text.

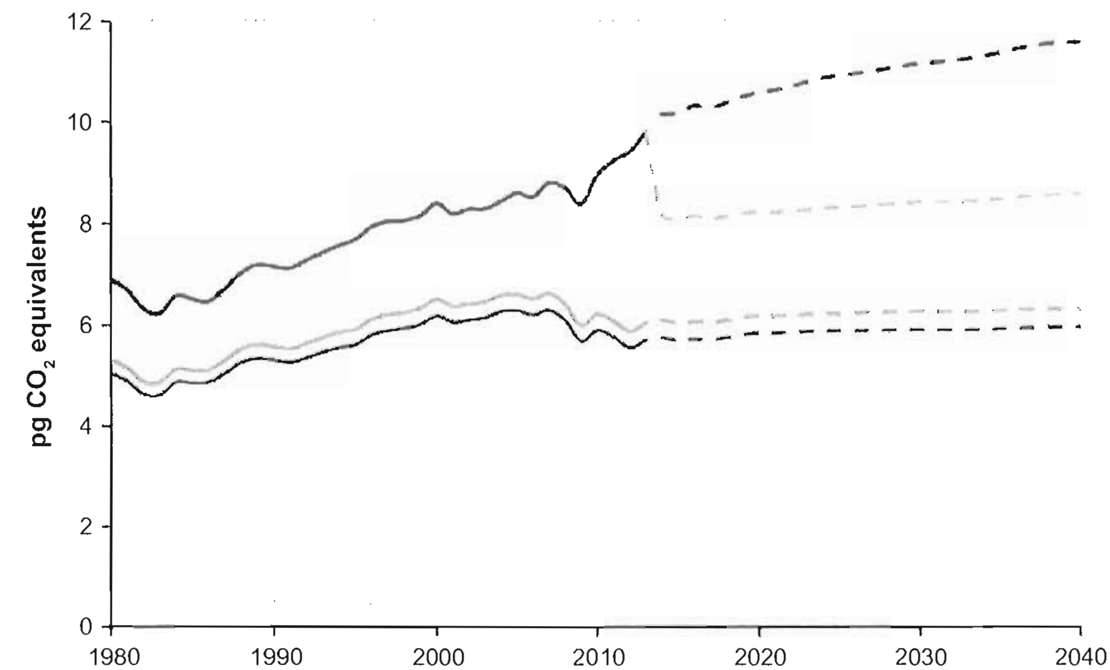

Figure 3 Trends in greenhouse gas emissions from fossil fuel use in the USA from 1980 to 2013 and future trends predicted until 2040 based on historical energy use and energy predictions in the *Annual Energy Outlook 2015*.[1] Shown are: emissions just for carbon dioxide (gray line); emissions for carbon dioxide and for methane using EPA assumptions, which undervalue the importance of methane (green line); emissions for carbon dioxide and methane based on emission factors for conventional natural gas, oil, and coal from Howarth et al,[11] mean methane emission estimates for shale gas of 12% based on Schneising et al[36] as discussed in the text, and a global warming potential for methane of 86 (red line); and future emissions for carbon dioxide and methane based on the same assumptions as for the red line, except assuming that shale gas emissions can be brought down to the level for conventional natural gas (blue line). Historical data are shown by solid lines; dashed lines represent future predictions.
Abbreviation: EPA, Environmental Protection Agency.

given unit of energy produced, carbon dioxide emissions are less for shale gas and conventional natural gas than those for oil and coal, the total greenhouse gas footprint of shale gas is substantially greater than that of the other fossil fuels when methane emissions are included (Figure 2). Note that this is true even for the low-end estimates of methane emissions from the Schneising et al study. The greenhouse gas footprint of conventional natural gas is also higher than that of conventional oil and coal for the mean estimate of methane emissions and still greater than or comparable to that of these other fuels even at the low-end estimate for methane emissions. Natural gas – and shale gas in particular – is not a bridge fuel when methane emissions are considered over an appropriate timescale.

Trends in greenhouse gas emissions from fossil fuels in the USA

Figure 3 shows the greenhouse gas emissions from all use of fossil fuels in the USA from 1980 to 2013 and projections for emissions through 2040, based on data for fossil fuel use and projections of future use from the EIA *Annual Energy Outlook 2015* report[1] and carbon dioxide emissions per unit of energy produced for each fuel.[11,22] Total carbon dioxide emissions fell in the early 1980s due to economic recession, but as the economy recovered, emissions rose steadily until the great recession of 2008. Carbon dioxide emissions continued to fall from 2008 to 2013 and are predicted to remain relatively flat through 2040.[1] President Obama and others have attributed the decrease in carbon dioxide emissions since 2008 to a switch from coal to shale gas,[21,50] although a recent analysis by Feng et al concludes that the sluggish economy was the more significant cause.[51]

When methane emissions are included in the analysis, we see some important differences in trends in national greenhouse gases. For the top line in Figure 3, methane emissions are included as carbon dioxide equivalents using the 20-year GWP of 86 from the IPCC fifth assessment[23] and methane emission factors from the 2011 study by Howarth et al[11] for coal, conventional oil, and conventional natural gas and a factor of 12% based on the satellite data discussed earlier for shale gas. In this analysis, methane contributes 28% of total fossil fuel emissions for the USA in 1980 and 42% in 2013 (Figure 3). The increasing trend in the relative importance of methane in the greenhouse gas emissions of the USA is due to an increasingly large portion of the nation's fuel mix coming from natural gas and particularly from shale gas for the time since 2009.[1] Shale gas production was negligible before 2005 (Figure 1) but rose to contribute 14% of all fossil fuel energy used in the USA in 2013.[1] Importantly, while carbon dioxide emissions fell between 2008 and 2013, total greenhouse gas emissions including methane fell only briefly in 2008 before beginning a rapid increase that lasted through 2013 and are projected to continue to rise through 2040.

The US EPA includes methane emissions in the natural gas inventory, but they do so in a manner that greatly undervalues their importance. This can be seen in Figure 3, where the green line that is just above and closely tracks the gray line for carbon dioxide emissions is based on EPA assumptions: a methane emissions rate of only 1.8% from natural gas and a GWP of 21 based on the 100-year time period from the second IPCC assessment from 1996.[52] Note that the EPA used this GWP value of 21 for many years, through 2013, before switching to the 100-year value of 25 in 2014 from the IPCC fourth assessment from 2007. The 2013 assessment of the IPCC gives a GWP value of 34 for the 100-year period but, as noted earlier, also states that the 100-year time frame is arbitrary. A shorter time frame, such as the 20-year GWP of 86 used in the top line in Figure 3, far better accounts for the importance of methane to global warming in the critical next few decades as the temperature is predicted to reach 1.5°C–2°C above the preindustrial baseline if methane emissions are not reduced.

Implications for policy on shale gas

As of January 2015, the US EPA has taken some steps to reduce emissions from shale gas, but how effective these will be in reducing methane emissions remains unclear. A draft regulation proposed in 2012 would have prevented the venting of methane during the flowback period following hydraulic fracturing, with some exceptions such as for wells in frontier regions not yet serviced by pipelines.[53] This would be important, since such venting can emit a large amount of methane.[11] However, the final regulation distinguishes between two phases of flowback, an "initial flowback stage" and a "separation flowback stage". Venting of methane and other gas is explicitly allowed during the initial stage, and recovery of the gas is only required during the separation stage.[53] The separation stage is supposed to commence as soon as it is technically feasible to use a flowback gas separator. At this stage, EPA requires that the gas be sold to market, reinjected into the ground, used as an onsite fuel, or, if none of these are possible, flared (ie, burned). No direct venting of gas is allowed during this separation flowback stage, "except when combustion creates a fire or safety hazard or can damage tundra, permafrost or waterways".[53] Much is left to operator judgment as to when the shift from the initial stage to the separation stage occurs and whether an exception is necessary, which would seem to make enforcement of these regulations difficult.

Further, EPA continues to ignore some methane emission sources, such as during the drilling phase. Caulton et al identified many wells that were emitting high levels of methane during this drilling phase, before the drillers had even reached the target shale, and long before hydraulic fracturing,[20] perhaps because drillers were encountering pockets of methane gas from abandoned conventional gas wells or abandoned coal mines. Our understanding of emission sources remains uncertain, with the study of shale gas methane emissions commencing only in the past few years.[6] Adequate regulation to reduce emissions requires better knowledge of sources, as well as better oversight and enforcement.

Nonetheless, methane emissions from shale gas can be reduced to some extent. I suggest that the best-case scenario would have these emissions reduced to the level for conventional natural gas, or ~3.8% for the full well-to-consumer life cycle. This best-case scenario is explored in Figure 3 (dashed blue line), where it is assumed that shale gas methane emissions are reduced from 12% to 3.8% as of 2014. Even still, methane accounts for 30% of total greenhouse gas emissions from fossil fuels in the USA throughout the period from 2014 to 2040 under this scenario, and total emissions continue to rise, albeit more slowly than without the aggressive reduction in shale gas methane emissions. This best-case scenario seems unlikely, and actual emissions from shale gas are likely to range between 3.8% and 12%, giving total greenhouse gas emissions for all fossil fuels that lie between the dashed red and blue lines in Figure 3.

Methane emissions severely undercut the idea that shale gas can serve as a bridge fuel over the coming decades, and we should reduce our dependence on natural gas as quickly as possible. One of the most cost-effective ways to do so is to replace in-building use of natural gas for domestic space and water heating with high-efficiency heat pumps. Even if the electricity that drives these heat pumps comes from coal, the greenhouse gas emissions are far less than from the direct use of natural gas.[12] Heating is the major use for natural gas in the USA, making this change of use imperative.

Concluding thoughts and a path forward

Should society continue to use coal rather than convert toward more electricity production from shale gas? Absolutely not. The carbon dioxide emissions from burning any fossil fuel will continue to influence the climate for hundreds of years into the future, and coal is the worst of the fossil fuels in terms of carbon dioxide emissions. Given the imperative of also reducing methane emissions to slow global warming over the coming few decades, though, the only path forward is to reduce the use of all fossil fuels as quickly as possible. There is no bridge fuel, and switching from coal to shale gas is accelerating rather than slowing global warming.

Fortunately, society does have a path forward: recent studies for the State of New York[54] and for the State of California[55] have demonstrated that we can move from a fossil fuel-driven economy to one driven totally by renewable energy sources (largely solar and wind) in a cost-effective way using only technologies that are commercially available today. The major part of the transition can be made within the next 15 years, largely negating the need for shale gas, with a complete transition possible by 2050. A critical part of these plans is to use modern, efficient technologies such as heat pumps and electric vehicles, which greatly reduce the overall use of energy. The cost of the transition is less than the cost currently paid for death and illness related to air pollution from using fossil fuels.[54] The costs of renewable energy today are equal to or lower than those from using fossil fuels, when the external costs to health and the climate are considered.

In June 2015, six of the largest oil and gas companies in Europe including BP and Shell called for a carbon tax as a way to slow global warming.[56] An editorial in the *New York Times* endorsed this idea,[56] and indeed, a carbon tax is perhaps the best way to equalize the playing field for renewable energy technologies. The International Monetary Fund estimates that subsidies to fossil fuels globally are in the range of $5 trillion per year, with much of this due to the effects of global warming and consequences on human health.[57] A carbon tax would help rectify these subsidies and help promote renewable energy. However, the editorial in the *Times* made a fundamental error by ignoring methane emissions when they wrote "this tax would reduce demand for high-carbon emission fuels and increase demand for lower emission fuels like natural gas".[56]

Any carbon tax should recognize the two faces of carbon: the two major greenhouse gases, carbon dioxide and methane, are both carbon gases. Both of these carbon gases are critically important, and the 2013 IPCC synthesis report tells us that the effects of global methane being emitted today matches the consequences of carbon dioxide emissions as drivers of global warming.[23] The modes of interaction with the planetary climate system are dramatically different, though. The climate is slow to respond to changes in carbon dioxide emissions, and so immediate reductions in emissions would take 30–40 years before having an influence on slowing warming, but the emissions have a warming effect on the climate that will persist for hundreds of years.[23,46,47] The climate responds quickly to changes in methane emissions, and reducing methane emissions is essential for slowing climate change over the coming 30–40 years; however, the methane remains in the atmosphere for little more than 1 decade, and methane emissions have no lasting influence on the Earth's climate systems in future centuries, unless global warming over the coming decades leads to fundamental thresholds and changes in the climate.[12,23,46,47]

A carbon tax that adequately addresses the immediacy of global climate change must include both carbon gases. Methane emissions should be taxed using the best available information on methane emissions. And the tax on methane should adequately reflect the importance of methane in current global warming and its influence in global warming over the critically important next few decades. Taxing methane emissions at 86 times the tax for carbon dioxide emissions, using the 20-year GWP from the most recent IPCC synthesis report,[23] would accomplish this.

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Disclosure

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Sustainable Energy Options

Excerpted from the writings of Mark Z. Jacobson

Rather than debating whether hydraulic fracturing for natural gas development can ever be made safe, we should instead be focusing on how to convert to a truly safe and sustainable energy system, including an unqualified commitment to energy efficiencies and conservation measures. Such a system would be comprised of wind, water, and solar (WWS) power, and would be cheaper than our current fossil fuel system over the long term.

Mark Z. Jacobson, a professor of Civil and Environmental Engineering at Stanford University, has extensively studied the ability to convert to a sustainable, renewable energy system. Excerpts and conclusions from his publications are set out in this paper.

Converting to Sustainable Energy Options Can Power and Benefit Our Nation

Jacobson has developed plans for conversion for individual states, the entire United States, and the world. In his research, Jacobson found that the greatest barriers to this conversion are not "technical or even economic" but are instead "social and political."[1]

> The plans contemplate all new energy powered with WWS by 2020, about 80-85% of existing energy replaced by 2030, and 100% replaced by 2050. Electrification plus modest efficiency measures would reduce each state's end-use power demand by a mean of 37.6% with ~85% of this due to electrification and ~15% due to end-use energy efficiency improvements. Remaining 2050 all-purpose end-use U.S. power demand would be met with ~31% onshore wind, ~19% offshore wind, ~29.6% utility-scale photovoltaics (PV), ~8.6% rooftop PV, ~7.5% concentrated solar power (CSP), ~1.3% geothermal power, ~0.37% wave power, ~0.13% tidal power, and ~2.5% hydroelectric power. Over the U.S. as a whole, converting would provide ~5 million 40-year construction jobs and ~2.4 million 40-year operation jobs for the energy facilities alone, the combination of which would outweigh the ~3.9 million jobs lost. Converting would also eliminate ~62,000 (19,000-116,000) of today's U.S. air pollution premature mortalities/year and avoid ~$510 (158-1,155) billion/year in today's U.S. health costs, equivalent to ~3.15 (0.98-7.13) percent of the 2012 U.S. gross domestic product. Converting would further eliminate ~$730 billion/year in 2050 global warming costs due to U.S. emissions. The health cost savings to the U.S. plus the climate cost savings to the world due to U.S. emission reductions would equal the cost of installing a 100% WWS U.S. system within ~11.0 (7.3-15.4) years.[2]

Conversion to a 100% WWS energy infrastructure would eliminate energy-related air pollution mortality and morbidity, and the associated health costs. For example, a world conversion to a WWS system would eliminate "2.5-3 million annual air pollution deaths."[3]

> The conversion to WWS should stabilize energy prices since fuel costs would be zero. On the other hand, because the fuel costs of fossil fuels rise over time, a WWS infrastructure in 2050 would save the average U.S. consumer $4,500/person/year compared with the 2050 energy cost of fossil fuels to perform the same work. Health and climate cost savings due to WWS would be another $3,100/person/year benefit, giving a total cost savings in 2050 of $7,600/person/year due to WWS.
>
> The new footprint over land required for converting the U.S. to WWS for all purposes is equivalent to ~0.44% of the U.S. land area, mostly in deserts and barren land, before accounting for land gained from eliminating the current energy infrastructure. The spacing area between wind turbines, which can be used for multiple purposes, including farmland, ranchland, grazing land, or open space, is equivalent to 1.7% of U.S. land area. Grid reliability can be maintained in multiple ways. The greatest barriers to a conversion are neither technical nor economic. They are social and political. Thus, effective polices are needed to ensure a

1 Delucchi and Jacobson, 2011. Providing all global energy with wind, water, and solar power, Part II: Reliability, system and transmission costs, and policies, Energy Policy 39, 1170.

2 Jacobson et al., 2014. 100% Wind, Water, Sunlight (WWS) All-Sector Energy Plans for the 50 United States, July 17, 2014 *Draft*, 1.

3 Jacobson, 2012. Why Natural Gas Warms the Earth More but Causes Less Health Damage Than Coal, so is not a Bridge Fuel nor a Benefit to Climate Change, October 31, 2012 *Draft*, 1.

rapid transition."[4]

Jacobson's roadmaps for states to convert to WWS detail anticipated infrastructure changes.

> In brief, [conversion] requires or results in the following changes:
>
> (1) Replace fossil-fuel electric power generators with wind tur- bines, solar photovoltaic (PV) plants and rooftop systems, concentrated solar power (CSP) plants, solar hot water heater systems, geothermal power plants, a few additional hydro-electric power plants, and a small number of wave and tidal devices.
>
> (2) Replace all fossil-fuel combustion for transportation, heating and cooling, and industrial processes with electricity, hydrogen fuel cells, and a limited amount of hydrogen combustion. Battery-electric vehicles (BEVs), hydrogen fuel cell vehicles (HFCVs), and BEV–HFCV hybrids…will replace all combustion-based passenger vehicles, trucks, buses, non-road machines, and locomotives sold...Long-distance trucks will be primarily BEV-HFCV hybrids and HFCVs. Ships…will similarly run on hydrogen fuel cells and electricity. Today, hydrogen-fuel-cell ships, tractors, forklifts, buses, passenger vehicles, and trucks already exist, and electric vehicles, ferries, and non-road machinery also exist. Electricity-powered air- and ground-source heat pumps, heat exchangers, and backup electric resistance heaters will replace natural gas and oil for home heating and air conditioning. Air- and ground-source heat pump water heaters powered by electricity and solar hot water preheaters will provide hot water for homes. High-temperatures for industrial processes will be obtained with electricity and hydrogen combustion. Petroleum products may still be used for lubrication and plastics as necessary, but such products will be produced using WWS power for process energy.
>
> (3) Reduce energy demand beyond the reductions described under (2) through energy efficiency measures. Such measures include retrofitting residential, commercial, institutional, and government buildings with better insulation, improving the energy-out/energy-in efficiency of end uses with more efficient lighting and the use of heat-exchange and filtration systems; increasing public transit and telecommuting, designing future city infrastructure to facilitate greater use of clean-energy transport; and designing new buildings to use solar energy with more daylighting, solar hot water heating, seasonal energy storage, and improved passive solar heating in winter and cooling in summer.
>
> (4) Boost economic activity by implementing the measures above. Increase jobs in the manufacturing and installation industries and in the development of new and more efficient technologies. Reduce social costs by reducing health-related mortality and morbidity and reducing environmental damage to lakes, streams, rivers, forests, buildings, and statues resulting from air and water pollution. Reduce social costs by slowing the increase in global warming and its impacts on coastlines, agriculture, fishing, heat stress, severe weather, and air pollution (which otherwise increases with increasing temperatures). Reduce long-term macroeconomic costs by eliminating exposure to future rises in fossil fuel prices.
>
> (5) The plan anticipates that the fraction of new electric power generators as WWS will increase starting today such that, by 2020, all new generators will be WWS generators. Existing conventional generators will be phased out over time, but by no later than 2050. Similarly, BEVs and HFCVs should be nearly the only new vehicles…sold…by 2020. The growth of electric vehicles will be accompanied by a growth of electric charging stations in residences, commercial parking spaces, service stations, and highway rest stops.
>
> (6) All new heating and cooling technologies installed by 2020 should be WWS technologies and existing technologies should be replaced over time, but by no later than 2050.
>
> (7) To ensure reliability of the electric power grids, several methods should be used to match renewable energy supply with demand and to smooth out the variability of WWS resources. These include (A) combining geographically-dispersed WWS resources as a bundled set of resources rather than as separate resources and using hydroelectric power to fill remaining gaps; (B) using demand-response grid management to shift times of demand to match better with the timing of WWS power supply; (C)

4 Jacobson et al., 2014. 100% Wind, Water, Sunlight (WWS) All-Sector Energy Plans for the 50 United States, July 17, 2014 *Draft*, 1-2.

over- sizing WWS peak generation capacity to minimize the times when available WWS power is less than demand and to provide power to produce heat for air and water and hydrogen for transportation and heating when WWS power exceeds demand; (D) integrating weather forecasts into system operation to reduce reserve requirements; (E) storing energy in thermal storage media, batteries or other storage media at the site of generation or use; and (F) storing energy in electric-vehicle batteries for later extraction (vehicle-to-grid)."[5]

Why Wind, Water and Solar Are the Best Technology Options to Fuel Our Healthy Future

Jacobson's state roadmaps rely on technologies that will reduce air and water pollution and global warming impacts.

> The WWS energy technologies chosen…exist and were ranked the highest among several proposed energy options for addressing pollution and public health, global warming, and energy security (Jacobson, 2009). That analysis used a combination of 11 criteria (carbon dioxide equivalent emissions, air-pollution mortality and morbidity, resource abundance, footprint on the ground, spacing required, water consumption, effects on wildlife, thermal pollution, water, chemical pollution/radioactive waste, energy supply disruption, and normal operating reliability) to evaluate each technology. Mined natural gas and liquid biofuels are excluded from the…plan for the reasons given below.[6]

Natural gas was excluded from Jacobson's analysis

> for several reasons. The mining, transport, and use of conventional natural gas for electric power results in at least 60–80 times more carbon-equivalent emissions and air pollution mortality per unit electric power generated than does wind energy over a 100-year time frame. Over the 10–30 year time frame, natural gas is a greater warming agent relative to all WWS technologies and a danger to the Arctic sea ice due to its leaked methane and black carbon-flaring emissions…Natural gas mining, transport, and use also produce carbon monoxide, ammonia, nitrogen oxides, and organic gases. Although natural gas emits less carbon dioxide per unit electric power than coal, two factors cause natural gas to increase global warming relative to coal: higher methane emissions and less sulfur dioxide emissions per unit energy than coal…[N]atural gas is not a near-term 'low' greenhouse-gas alternative, in absolute terms or relative to coal. Moreover, it does not provide a unique or special path to renewable energy, and as a result, it is not bridge fuel and is not a useful component of a sustainable energy plan.
>
> Rather than use natural gas in the short term, [Jacobson et al.,] propose[s] to move to a WWS-power system immediately, on a worldwide scale, because the Arctic sea ice may disappear in 20–30 years unless global warming is abated (e.g., Pappas, 2012). Reducing sea ice uncovers the low-albedo Arctic Ocean surface, accelerating global warming in a positive feedback. Above a certain temperature, a tipping point is expected to occur, accelerating the loss to complete elimination (Winton, 2006). Once the ice is gone, regenerating it may be difficult because the Arctic Ocean will reach a new stable equilibrium (Winton, 2006). The only potential method of saving the Arctic sea ice is to eliminate emissions of short-lived global warming agents, including methane (from natural gas leakage and anaerobic respiration) and particulate black carbon (from natural gas flaring and diesel, jet fuel, kerosene burning, and biofuel burning)."[7]

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Converting to Sustainable Energy Is Feasible

Jacobson has documented that we have the sustainable energy capacity necessary to power the United States.

5 Jacobson et al., 2013. Examining the feasibility of converting New York State's all-purpose energy infrastructure to one using wind, water, and sunlight, Energy Policy 57, 586.

6 For reasons why nuclear power and coal with carbon capture are also excluded, see Jacobson and Delucchi (2011).

7 Jacobson et al., 2013. Examining the feasibility of converting New York State's all-purpose energy infrastructure to one using wind, water, and sunlight, Energy Policy 57, 586-587.

The United States has more wind, solar, geothermal, and hydroelectric resources than is needed to supply the country's energy for all purposes in 2050. In this section, U.S. wind, solar, geothermal, hydroelectric, tidal, and wave resources are examined.

Wind

…Results suggest that the U.S. mean onshore capacity factor may be 30.5% and offshore, 37.3%. Locations of strong onshore wind resources include the Great Plains, northern parts of the northeast, and many areas in the west. Weak wind regimes include the southeast and the westernmost part of the west coast continent. Strong offshore wind resources occur off the east coast north of South Carolina and the Great Lakes. Very good offshore wind resources also occur offshore the west coast and offshore the southeast and gulf coasts…[T]he 2050 clean-energy plans require 1.7% of U.S. onshore land and 0.88% of U.S. onshore-equivalent land area sited offshore for wind-turbine spacing to power 50% of all-purpose 2050 U.S. energy. The mean capacity factor for onshore wind needed is 35.2% and that for offshore wind is 42.5%. Figure 1 suggests that much more land and ocean areas with these respective capacity factors or higher are available than are needed for the plans.

Solar

…The best solar resources in the U.S. are broadly in the Southwest, followed by the Southeast, the Northwest, then the Northeast. The land area in 2050 required for non-rooftop solar under the plan here is equivalent to ~0.41% of U.S. land area, which is a very small percent of area relative to the area of strong solar resources available in Figure 2 and in other solar resource analyses. As such, we do not believe there is a limitation in solar resources available for implementing the 50 state plans proposed …

Geothermal

The U.S. has significant traditional geothermal resources (volcanos, geysers, and hot springs) as well as heat stored in the ground due to heat conduction from the interior of the Earth and solar radiation absorbed by the ground. In terms of traditional geothermal, the U.S. has an identified resource of 9.057 GW[8] deliverable power distributed over 13 states, undiscovered resources of 30.033 GW deliverable power, and enhanced recovery resources of 517.8 GW deliverable power (USGS, 2008). As of April, 2013, 3.386 GW of geothermal capacity had been installed in the U.S. and another 5.15-5.523 GW was under development (GES, 2013).

States with identified geothermal resources (and the percent of resource available in each state) include Colorado (0.33%), Hawaii (2.0%), Idaho (3.68%), Montana (0.65%), Nevada (15.36%), New Mexico (1.88%), Oregon (5.96%), Utah (2.03%), Washington State (0.25%), Wyoming (0.43%), Alaska (7.47%), Arizona (0.29%), and California (59.67%). All states have the ability to extract heat from the ground for heat pumps. However, such energy would not be used to generate electricity; instead it would be used directly for heat, thereby reducing electric power demand for heat although electricity would still be needed to run heat pumps…

Hydroelectric

Under the plan proposed here, conventional hydro will supply 47.26 GW of delivered power, or 2.46% (Table 1) of U.S. 2050 total end-use power demand for all purposes. Thus, 2010 U.S. plus Canadian delivered hydropower (34.8 GW) already provides 73.6% of the U.S. 2050 delivered hydropower power goal. The plan here calls for very few new hydroelectric dams. Thus, the additional 12.5 GW of delivered hydro would be obtained by increasing the capacity factor of existing dams to an average of 53.1%. Existing dams currently provide less than their maximum capacity due to an oversupply of energy available from other sources and multiple priorities affecting water use…

Tidal

Tidal (or ocean current) is proposed to comprise about 0.13% of U.S. total power in 2050 (Table 1). The U.S. currently has the potential to generate 50.8 GW (445 TWh/yr)[9] of delivered power from tidal streams (Georgia Tech Research Corporation, 2011). States with the great-

8 GW or gigawatt. One GW is equal to one billion watts or 1,000 megawatts (MW).

9 TWh, or terawatt hour. One TW is equal to one trillion watts.

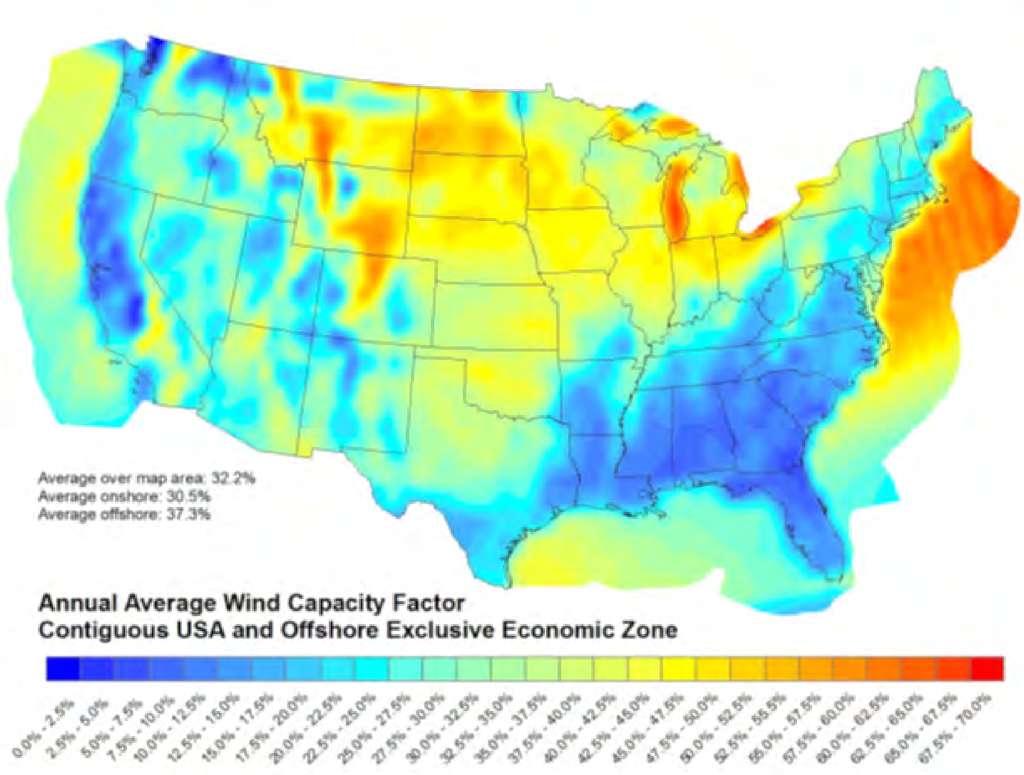

Figure 1. Modeled 2006 annually averaged capacity factor for 5 MW RePower wind turbines (126-m diameter rotor) at 100-m hub height above the topographical surface in the contiguous United States. The model used was GATOR-GCMOM (Jacobson et al., 2007; Jacobson, 2010), which was nested for one year from the global to regional scale with resolution on the regional scale of 0.6 degrees W-E x 0.5 degrees S-N.

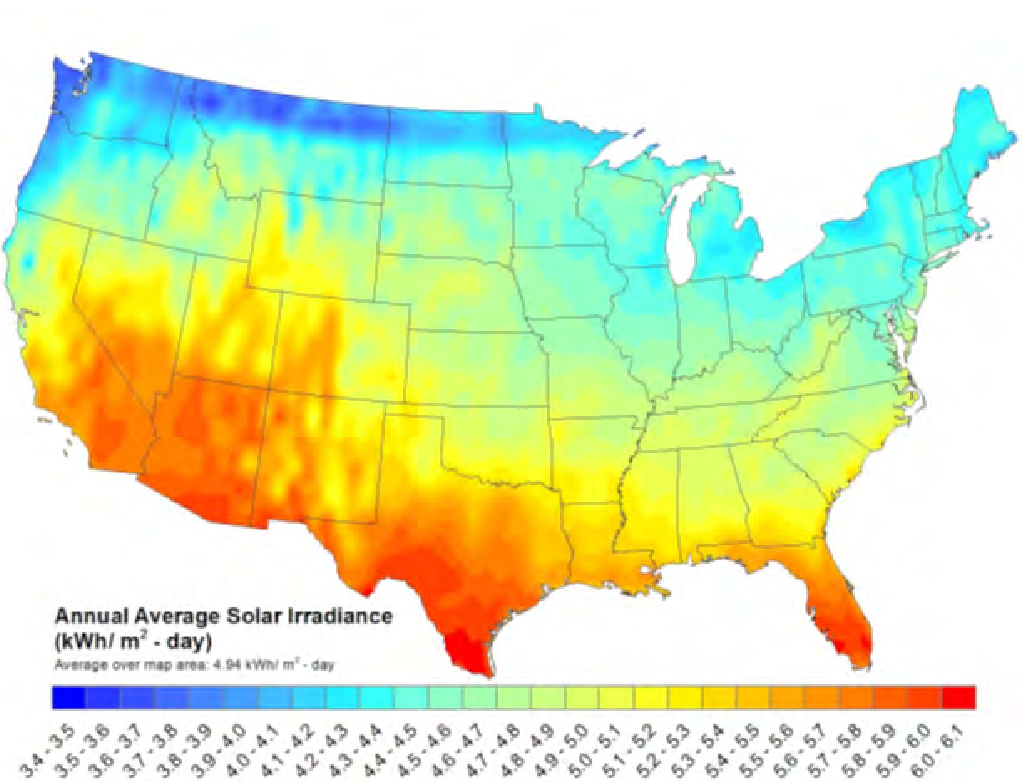

Figure 2. Modeled 2013 annual downward direct plus diffuse solar radiation at the surface (kWh/m2/day) available to photovoltaics in the contiguous United States. The model used was GATOR-GCMOM (Jacobson et al., 2007; Jacobson, 2010), which simulates clouds, aerosols gases, weather, radiation fields, and variations in surface albedo over time. The model was nested from the global to regional scale with resolution on the regional scale relatively coarse (0.6 deg W-E x 0.5 deg S-N).

Energy Technology	Rated power of one plant or device (MW)	Percent of 2050 power Demand met by plant/device	Nameplate capacity of existing plus new plants or devices (MW)	Percent of nameplate capacity already installed 2013	Number of new plants or devices needed for U.S.	Percent of U.S. land area for footprint of new plants / devices[A]	Percent of U.S. land area for spacing of new plants / devices
Onshore wind	5	30.98	1,818,769	3.36	351,547	0.00005	1.7057
Offshore wind	5	18.99	904,726	0.00	180,945	0.00002	0.8779
Wave device	0.75	0.37	33,657	0.00	44,876	0.00026	0.0122
Geothermal plant	100	1.29	28,935	8.32	265	0.00099	0.0000
Hydroelectric plant	1300	2.46	92,816	95.92	4	0.02701	0.0000
Tidal turbine	1	0.13	10,687	0.00	10,687	0.00003	0.0004
Res. roof PV	0.005	4.73	641,416	0.55	127,573,149	0.05208	0.0000
Com/gov roof PV	0.1	3.89	495,593	0.36	4,938,184	0.04032	0.0000
Solar PV plant[B]	50	29.62	2,923,981	0.06	58,444	0.23859	0.0000
Utility CSP plant	100	7.54	833,012	0.00	8,330	0.17275	0.0000
Total		100.00	7,783,592	2.05	0	0.53	2.60
Total new land[C]						0.44	1.71

A Total land area for each state is given in Jacobson, M.Z., G. Bazouin, and M.A. Delucchi, 2014a. Spreadsheets of calculations for this study. http://web.stanford.edu/group/efmh/jacobson/Articles/I/WWS-50-USState-plans.html.

B The solar PV panels used for this calculation are Sun Power E20 panels. The capacity factors used for residential and commercial/government rooftop solar production estimates are given in Jacobson et al. (2014a) for each state. For utility solar PV plants, nominal "spacing" between panels is included in the plant footprint area. The capacity factors assumed for utility PV are given in Jacobson et al. (2014a).

C The footprint area requiring new land is equal to the footprint area for new onshore wind, geothermal, hydroelectric, and utility solar PV. Offshore wind, wave and tidal are in water, and so do not require new land. The footprint area for rooftop solar PV does not entail new land because the rooftops already exist and are not used for other purposes (that might be displaced by rooftop PV). Only onshore wind entails new land for spacing area. The other energy sources either are in water or on rooftops, or do not use additional land for spacing. Note that the spacing area for onshore wind can be used for multiple purposes, such as open space, agriculture, grazing, etc.

Table 1. Number, capacity, footprint area, and spacing area of WWS power plants or devices needed to provide the U.S. total annually-averaged end-use power demand for all purposes in 2050, accounting for transmission, distribution, and array losses. Individual tables for each state and their derivation are given in Jacobson et al. (2014a).

…Short- and moderate distance transmission and distribution losses for offshore wind and all other energy sources treated here were assumed to be 5-10%. Since each state's plan is self-contained, extra-long distance transmission was assumed not necessary. However, If it were needed, losses from it would be 1.4-6% per 1000 km plus 1.3-1.8% in the station equipment (Delucchi and Jacobson, 2011).

est potential offshore tidal power include Alaska (47.4 GW), Washington State (683 MW), Maine (675 MW), South Carolina (388 MW), New York (280 MW), Georgia (219 MW), California (204 MW), New Jersey (192 MW), Florida (166 MW), Delaware (165 MW), Virginia (133 MW), Massachusetts (66 MW), North Carolina (66 MW), Oregon (48 MW), Maryland (35 MW), Rhode Island (16 MW), Alabama (7 MW), Texas (6 MW), Louisiana (2 MW). The available power in Maine, for example, is distributed over 15 tidal streams. The present state plans call for extracting just 2.5 GW of delivered power, which would require an installed capacity of 10.7 GW of tidal turbines.

Wave

Wave power is also proposed to comprise 0.37%, or about 7.1 GW, of the U.S. total end-use power demand in 2050 (Table 1). The U.S. has a recoverable delivered power potential (after accounting for array losses) of 135.8 GW (1,190 TWh) along its continental shelf edge (EPRA, 2011). This includes 28.5 GW of recoverable power along the West Coast, 18.3 GW along the East Coast, 6.8 GW along the Gulf of Mexico, 70.8 GW along Alaska's coast, 9.1 GW along Hawaii's coast, and 2.3 GW along Puerto Rico's coast. Thus, all states border the oceans have wave power potential. The available supply is almost 20 times the delivered power needed under this plan."

…Short- and moderate distance transmission and distribution losses for offshore wind and all other energy sources treated here were as-

> sumed to be 5-10%. Since each state's plan is self-contained, extra-long distance transmission was assumed not necessary. However, If it were needed, losses from it would be 1.4-6% per 1000 km plus 1.3-1.8% in the station equipment (Delucchi and Jacobson, 2011).[10]

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Sustainable Energy is Reliable

Jacobson has determined that WWS can provide the power when and where it is needed.

> An important concern to address in a clean -energy economy is whether electric power demand can be met with WWS supply on a minutely, daily, and seasonal basis…Several studies have examined whether up to 100% penetrations of WWS resources could be used reliably to match power with demand (e.g., Jacobson and Delucchi, 2009; Mason et al., 2010; Hart and Jacobson, 2011, 2012; Connolly et al., 2011; Elliston et al., 2012; NREL (NationalRenewableEnergyLaboratory), 2012; Rasmussen et al., 2012; Budischak et al.,2013). Using hourly load and resource data and accounting for the intermittency of wind and solar, both Hart and Jacobson (2011) and Budischak et al. (2013) found that up to 99.8% of delivered electricity could be produced carbon-free with WWS resources over multiple years…Eliminating remaining carbon emission is challenging but can be accomplished in several ways. These include using demand response and demand management, which will be facilitated by the growth of electric vehicles; oversizing the grid and using the excess power generated to produce district heat through heat pumps and thermal stores and hydrogen for other sectors of the energy economy (e.g. heat for buildings, high-temperature processes, and fuel-cell vehicles); using concentrated solar power storage to provide solar power at night; and storing excess energy at the site of generation with pumped hydroelectric power, compressed air (e.g. in underground caverns or turbine nacelles), flywheels, battery storage packs, or batteries in electric vehicles (Kempton and Tomic, 2005). Oversizing the peak capacity of wind and solar installation to exceed peak inflexible power demand can reduce the time that available WWS power supply is below demand, thereby reducing the need for other measures to meet demand. The additional energy available when WWS generation exceeds demand can be used to produce hydrogen (a storage fuel) by electrolysis for heating processes and transportation and to provide district heating. Hydrogen must be produced in any case as part of the WWS solution. Oversizing and using excess energy for hydrogen and district heating would also eliminate the current practice of shutting down (curtailing) wind and solar resources when they produce more energy than the grid can accommodate. Denmark currently uses excess wind energy for district heating using heat pumps and thermal stores (e.g., Elsman, 2009).[11]

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10 Jacobson et al., 2014. 100% Wind, Water, Sunlight (WWS) All-Sector Energy Plans for the 50 United States, July 17, 2014 *Draft*, 10-17.

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Sustainable Energy Is Cost Effecient

The cost of sustainable energy will continue to decrease over time. By comparison, conventional fuel costs are expected to rise over time, making sustainable energy the better near term and long term choice based on cost.

> With a 100% WWS market penetration proposed for 2050, significant cost reductions are expected not only due to anticipated technology improvements and the zero fuel cost of WWS resources, but also due to less expensive manufacturing and streamlined project deployment from increased economies of scale. On the other hand, private electricity costs of conventional fuels are expected to continue to rise.
>
> Costs of onshore wind and hydroelectric power are expected to remain low through 2030. The cost of wind-generated electricity has declined recently due to the rapid decline in turbine prices and improvements in technology leading to increased net capacity factors (e.g. increases in average hub height and rotor diameter). National costs of solar PV are expected to fall to 4.5-10 cents/kWh by 2030, with the low-end reduction for utility-scale solar and the high end for residential. With this expected price reduction, solar PV is expected to be competitive with other energy sources throughout the U.S. by significantly before 2030.
>
> Due to the nascent state of the wave and tidal industries (the first commercial power projects have just now been deployed in the United States), it is difficult to make accurate cost estimates. Roughly 50 different tidal devices are in the proof-of-concept or prototype development stage, but large-scale deployment costs have yet to be demonstrated. Although current wave power-generating technologies appear to be expensive, they might follow a learning curve similar to that of the wind power industry. Industry analyses point toward a target annualized cost of 4-11 U.S. ¢/kWh for wave and 5-7 ¢/kWh for tidal power (Asmus and Gauntlett, 2012), although a greater understanding of costs will become available once systems in the field have been in operation for a few years.
>
> …[M]any future wind and solar farms may be far from population centers, requiring long-distance transmission. For long-distance transmission, high-voltage direct-current (HVDC) lines are used because they result in lower transmission line losses per unit distance than alternating-current (AC) lines (Table 1, footnote). The cost of extra-long-distance HVDC transmission on land (1,200-2,000 km) ranges from 0.3-3 U.S. cents/kWh, with a median estimate of ~1 U.S. cent/kWh (Delucchi and Jacobson, 2011). A system with up to 25% undersea HVDC transmission would increase the additional long-distance transmission cost by less than 20%. Transmission needs and costs can be reduced by considering that decreasing transmission capacity among interconnected wind farms by 20% reduces aggregate power by only 1.6% (Archer and Jacobson, 2007).
>
> … [E]ven with extra-long-distance HVDC transmission, the costs of hydroelectric and wind power are already cost competitive with fossil electricity sources. In fact, a state by-state examination of fractional electricity generation by wind versus cost of electricity by state provides the following results. From January-July 2013, two states (South Dakota and Iowa) generated nearly 28% of their electric power from wind. Nine states generated more than 13% from wind (South Dakota, Iowa, Kansas, Minnesota, North Dakota, Oklahoma, Idaho, Colorado, and Oregon). The tenth state, Texas, generated 9.3% of its electricity from wind (EIA, 2013a). The average increase in residential electricity price from 2003-2013 in the 10 states with the highest fraction of their electricity from wind was 3 ¢/kWh. The price increase during the same period in all other 40 states was 4 ¢/kWh. The price increase in Hawaii during the same period

was 19.9 ¢/kWh. This result suggests that states that invested more in wind saw less of a price increase than states that invested less in wind, contrary to the perception that the addition of an intermittent renewable energy source causes an average increase in electricity price.[12]

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Sustainable Energy Options Avoid Expensive Air Pollution Costs and the Damage it Does to Our Health and Lives

Jacobson has also considered the considerable human health implications of converting to WWS.

> *The top-down approach to estimate air-pollution mortality in the U.S.* The premature human mortality rate in the U.S. due to cardiovascular disease, respiratory disease, and complications from asthma due to air pollution has been estimated conservatively by several sources to be at least 50,000-100,000 per year. In Braga et al. (2000), the U.S. air pollution mortality rate was estimated at about 3% of all deaths. The all-cause death rate in the U.S. is about 833 deaths per 100,000 people and the U.S. population in 2012 was 313.9 million. This suggests a present-day air pollution mortality rate in the U.S. of ~78,000/year. Similarly, from Jacobson (2010), the U.S. death rate due to ozone and particulate matter was calculated with a three-dimensional air pollution-weather model to be 50,000-100,000 per year. These results are consistent with those of McCubbin and Delucchi (1999), who estimated 80,000 to 137,000 due to all anthropogenic air pollution in the U.S. in 1990, when air pollution levels were higher than today.
>
> *The bottom-up approach to estimate air-pollution mortality in the U.S.* This approach involves combining measured countywide or regional concentrations of particulate matter ($PM_{2.5}$) and ozone (O_3) with a relative risk as a function of concentration and with population by county. From these three pieces of information, low, medium, and high estimates of mortality due to $PM_{2.5}$ and O_3 pollution are calculated with a health-effects equation (e.g., Jacobson, 2010)…The medium values for the U.S. for $PM_{2.5}$ were ~48,000 premature mortalities/yr…and for O_3 were ~14,000 premature mortalities/yr, with a range of 7,000-21,000/yr. Thus, overall, the bottom-up approach gives ~62,000 (19,000-116,000) premature mortalities/year for $PM_{2.5}$ plus O_3. The top-down estimate (50,000–100,000), from Jacobson (2010), falls within the bottom-up range.
>
> …[T]he total social cost [of fossil fuel-based energy] due to air pollution mortality, morbidity, lost productivity, and visibility degradation in the U.S. today is conservatively estimated from the ~62,000 (19,000-116,000) premature mortalities/yr to be $510 (158-1,155) billion/yr (using an average of $8.2 million/mortality for the low and medium numbers of mortalities and $10 million/mortality for the high number). Eliminating these costs today represents a savings equivalent to ~3.15 (0.98-7.13)% of the 2012 U.S. gross domestic product.
>
> Energy-related greenhouse gas emissions from the U.S. cause climate-related damage to the world… Ackerman et al. (2008) estimated global warming damage costs (in 2006 U.S. dollars) to the U.S. alone due to world emissions of greenhouse gases and warming aerosol particles of $271 billion/yr in 2025, $506 billion/yr in 2050, $961 billion/yr in 2075, and $1.9 trillion/yr in 2100. That analysis accounted for severe storm and hurricane damage, real estate loss, energy-sector costs, and water costs. The largest of these costs was water costs. It did not account for increases in mortality and illness due to increased heat stress, influenza, malaria, and air pollution or increases in forest-fire incidence, and as a result it probably underestimated the true cost.
>
> …[C]onverting the U.S. to WWS would avoid $510 (158-1,155) billion/year in air pollution

12 Jacobson et al., 2014. 100% Wind, Water, Sunlight (WWS) All-Sector Energy Plans for the 50 United States, July 17, 2014 *Draft*, 24-27.

health costs to the U.S. and ~$730 billion/yr in global-warming damage costs worldwide by 2050. The U.S.-mean installed capital cost of the electric power system proposed here, weighted by the proposed installed capacity of each generator, is approximately $1.8 million/MW. Thus, for new nameplate capacity, summed over all generators, of 7.63 TW (Table 1), the total capital cost of a U.S. WWS system is ~ $13.7 trillion. As such, the health-cost savings alone to the U.S. due to converting to WWS may equal the installation cost of WWS generators within 27 (12-87) years. The health-cost savings to the U.S. plus the climate-cost savings to the world may equal the generator cost within 11 (7.3-15.4) years.

…[M]odels predict the creation of ~4.95 million 40-year construction jobs and ~2.4 million 40-year operation and maintenance jobs for the WWS generators proposed. The shift to WWS will simultaneously result in the loss of ~3.88 million in the current fossil-based electricity generation, petroleum refining, and uranium production industries in the U.S. Thus, a net of ~3.48 million 40-year jobs will be created in the U.S. The direct and indirect earnings from WWS amount to $271 billion/year during the construction stage and $152 billion/yr for operation. The annual earnings lost from fossil-fuel industries total ~$233 billion/yr giving a net gain in annual earnings of ~$190 billion/yr. These numbers are not meant to be a precise forecast, but rather an indication of the economic effect WWS electricity generation may have on the U.S. The actual job and revenue impacts are subject to various uncertainties associated with progress in technology, projects scale and policies. Overall, the positive socio-economic impacts of WWS resource electricity implementation are expected to exceed significantly the negative impacts."[13]

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A Sustainable Energy Future is Achievable

Sustainable energy to fuel our future is within our grasp. To get the health, environment and economic benefits of sustainable energy and leave behind the damage of shale gas and continued use of fossil fuels, we just need to take the steps to make it happen.

> Manpower, materials, and energy resources do not constrain the development of WWS power; the obstacles to realizing this transformation are primarily social and political, not technological.[14] With clear direction in the form of broad-based policies and relatively small social changes "it may be possible for a 25% conversion in 10-15 years, 85% in 20-30 years, and 100% by 2050."[15]
>
> Least-cost energy system optimization studies and practical implementation considerations will determine the most efficient design and operation of the energy system… Several methods exist to match renewable energy supply with demand and to smooth out the variability of WWS resources" and to reduce costs associated with the transition.[16]

In the United States, approximately 40% of the total annual carbon dioxide emissions are associated with the generation of electricity.[17] Implementation of a WWS energy system will essentially "eliminate the costs related to these emissions such as energy-related global warming; air, soil, and water pollution; and energy insecurity.[18]

13 Jacobson et al., 2014. 100% Wind, Water, Sunlight (WWS) All-Sector Energy Plans for the 50 United States, July 17, 2014 *Draft*, 36.

14 Delucchi and Jacobson, 2011. Providing all global energy with wind, water, and solar power, Part II: Reliability, system and transmission costs, and policies, Energy Policy 39, 1170.

15 Delucchi and Jacobson, 2011. Providing all global energy with wind, water, and solar power, Part II: Reliability, system and transmission costs, and policies, Energy Policy 39, 1179.

16 Jacobson, et al., 2014. A 100% Wind, Water, Solar (WWS) All-Sector Energy Plan for Washington State, July 14, 2014 *Draft*, 44.

17 Hart and Jacobson, 2011, A Monte Carlo approach to generator portfolio planning and carbon emissions assessments of systems with large penetrations of variable renewables, Energy Policy 36, 2278, citing Energy Information Administration. Annual energy outlook 2009, table a18, http://www.eia.doe.gov/oiaf/aeo/pdf/appendixes.pdf; 2009.

18 Jacobson, et al., 2014. A 100% Wind, Water, Solar (WWS) All-Sector Energy Plan for Washington State, July 14, 2014 *Draft*, 46.

Testimony of Mark Szybist
House Democratic Policy Committee
Harrisburg, March 21, 2016

Chairman Vitali, Honorable Members of the Committee: good morning, and thank you for the invitation to testify today on the question of natural gas incentives in Pennsylvania.

My name is Mark Szybist; I am an attorney by training, and I work as a Senior Program Advocate for the Natural Resources Defense Council. NRDC is a national environmental organization with more than 90,000 members and online activists in Pennsylvania, and offices in New York, Washington, D.C., Chicago, Santa Monica, San Francisco, Montana, and Beijing. I am based in NRDC's Washington, D.C. office, but my work focuses on Pennsylvania environmental issues, especially implementation of the Clean Power Plan.

The question of today's hearing is whether Pennsylvania should incentive natural gas. My testimony will address this question as it applies to the Clean Power Plan, the federal initiative to reduce carbon pollution from power plants. In terms of the Clean Power Plan, I would state the question as follows: whether the Commonwealth should incentivize new natural gas power plants by exempting those plants from its State Plan implementing the Clean Power Plan. My answer to this question is: no. Pennsylvania should not incentive new gas plants. Instead, it should cover those plants in its State Plan.

The Clean Power Plan is an example of a kind of lawmaking that lawyers call cooperative federalism, in which the federal government and state governments work together to address problems that are too complex for either to address alone. In the case of the Clean Power Plan, the EPA has established a series of carbon pollution reduction targets for the states. These targets will be phased in over time, and the states have an extraordinary range of tools to meet them – expanding consumer-side energy efficiency in homes, factories, and government buildings; generating more electricity from zero-emitting sources like the wind and the sun; utilizing the full capacity of existing but underutilized natural gas plants; burning coal more efficiently at coal plants; and so on.

Several coal companies and other parties, including 27 states, have sued the EPA over the Clean Power Plan. (Sixteen other states, and many generators, business groups, and environmental organizations, have also intervened on the side of the EPA; Pennsylvania is one of three states that is not participating in the lawsuit). The opponents' claims will be decided by the federal Court of Appeals for the District of Columbia after oral arguments in June. Meanwhile, last month the U.S. Supreme Court issued a "stay" order that prohibits the EPA from enforcing the Clean Power Plan until the litigation is over. During the stay, states can continue working on their state plans, and Governor Wolf's administration has wisely committed to doing so. As DEP Secretary Quigley pointed out to the House Appropriations Committee a couple weeks ago, continuing work on the State Plan is the prudent course for Pennsylvania. On the one hand, given the way that cheap, oversupplied natural gas and other factors are transforming its power sector, Pennsylvania needs to do this work anyway. On the other hand, failing to plan would leave the state flat-footed if the Clean Power Plan is ultimately upheld – and NRDC is confident that it will be.

For the purposes of the Clean Power Plan, a new gas power plant is a plant that started construction after January 8, 2014. One of the decisions that states have to make in implementing the Clean Power Plan is whether to include new plants in their State Plans – and thereby make them compete against existing plants on an equal footing – or to leave them out and thereby give them a competitive advantage. Inclusion and exclusion are both options for states because existing power plants and new power plants are covered under two different sections of the Clean Air Act.

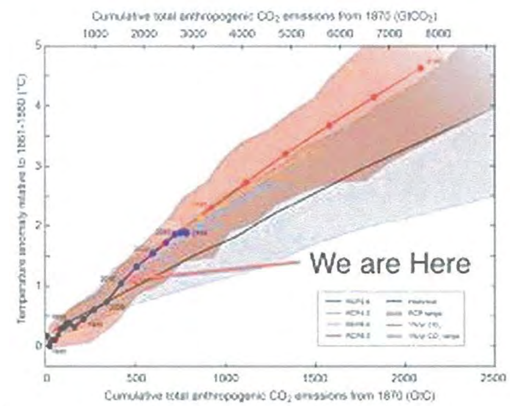
If Pennsylvania's State Plan covers new power plants, all fossil-fuel plants of 25 megawatts (MW) or more will be covered by a reasonable, growth-based cap on carbon pollution. This cap will not only cut carbon pollution; it will also cut emissions of harmful co-pollutants like sulfur dioxides and particulate matter; incentivize the use of energy efficiency to lower both emissions and electricity bills; and allow Pennsylvania's economy to prosper. Based on comments that generators and other stakeholders made during the DEP's listening sessions on the Clean Power Plan last fall, the Commonwealth is likely to choose is a mass-based compliance approach in which power plants have to buy carbon "allowances" to cover their pollution. In practical terms, covering new as well as existing power plants would mean that *all* coal and gas power plants have to buy allowances to cover the carbon pollution they emit, and all are subject to the growth-based cap. If this sounds like common sense, it is. It will ensure a level playing field for existing plants and new plants, and ensure that pollution reductions from existing plants are not compromised by huge pollution increases from new plants.

By contrast, if Pennsylvania leaves new gas power plants out of the state plan, so that only plants built before 2014 would have to stay under the cap and buy carbon allowances, it would create an incentive for new power plants. New plants could operate without carbon pollution limits and carbon pricing, and this would give them a built-in, competitive advantage over existing plants. In this kind of distorted market, we would likely see the premature closure of existing gas plants and the unnecessary construction of new plants, with the construction costs passed on to electricity ratepayers. We would see pollution "leak" to new plants from the existing plants that are covered by the state cap. The new plants would have to be supplied by new pipelines, and the extra gas they burned would be produced by more hydraulic fracturing. A greater number of coal plants would probably retire.

Right now, there are at least five new natural gas power plants in the Commonwealth that are either under construction or recently finished construction – in Jessup, Lackawanna County (1,500 MW); Shamokin Dam, Snyder County (1,224 MW); Clinton Township, Lycoming County (825 MW); Asylum Township, Bradford County (825 MW); and Salem Township, Luzerne County (1,029 MW). The combined planned capacity for these plants is more than 5,000 MW. In addition, Talen Energy has announced that it will convert its Brunner Island coal-fired power plant to fire gas as well as coal. Other new gas plants have been proposed in Clinton County and Lawrence County.

What the construction of these new power plants tells us is that Pennsylvania does not need incentives for new natural gas power plants. Those plants are being built because Pennsylvania is sitting on top of the most productive shale gas formations in the United States, natural gas is oversupplied and cheap (not to mention already heavily incentivized, on both the federal and the state level), and neither of these things will change any time soon. What Pennsylvania ought to incentivize is energy efficiency, our lowest-cost energy resource (for instance, by improving its building codes and removing the arbitrary limits on efficiency in Act 129) and zero-emitting renewable energy from the wind and the sun. Because of the potential health benefits, job benefits, and electricity bill benefits – as well as climate impacts – expanding clean energy now makes sense for the Commonwealth with or without the Clean Power Plan, and will help Pennsylvania meet its carbon reduction targets when the time comes to do so.

How to set National GHG Emissions Reduction Target After the 2015 Paris Climate Agreement



Donald A. Brown

Scholar In Residence and Professor

Widener University School Of Law

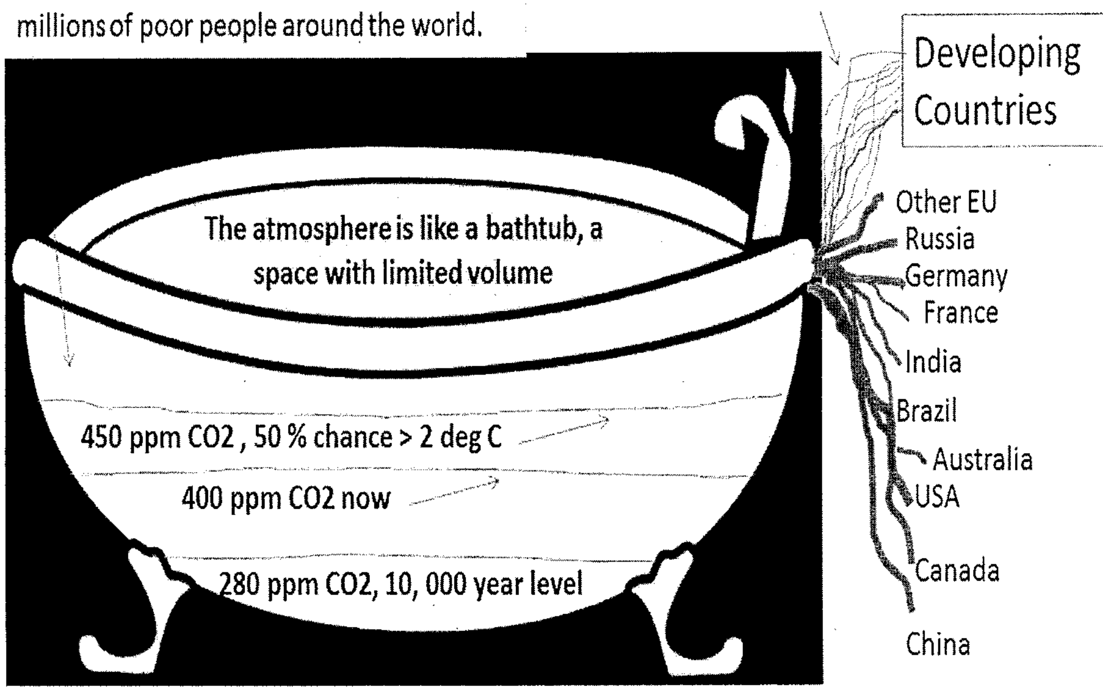
Major Positive Developments in Paris

PARIS2015 UN CLIMATE CHANGE CONFERENCE COP21·CMP11

- 186 nations made commitments to reduce ghg emissions, far short of 2° C goal
- Nations agreed to limit the increase in global average temperatures to "well below 2° C" and to "pursue efforts" to limit temperature increase to 1.5 ° C.
- The Paris Agreement, **GHG emissions must be no greater than sinks by the second half of this century**

The Justice Question: What levels of GHGs will be permitted in the bathtub given that the higher the levels--the greater the harms to those countries and millions of poor people that have done little to fill the bathtub and given some levels of warming are an existential threat to millions of poor people around the world.

The Equity Question: Who gets to fill the rest of the atmospheric bathtub given limited remaining space to limit atmospheric GHG concentrations to safe levels, different historical and per capita emissions that have filled the bathtub to current levels, and the needs of poor countries to grow economically.



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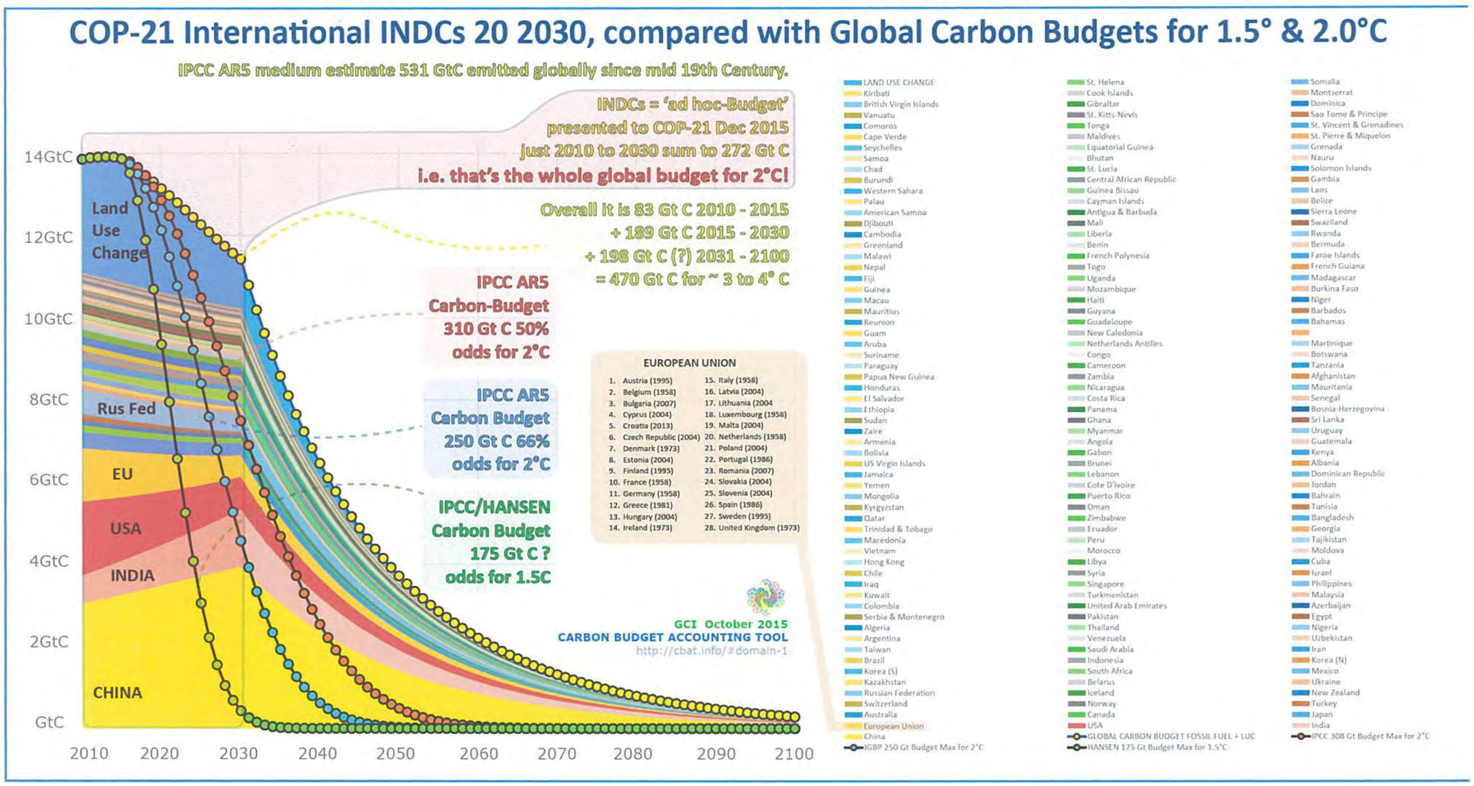

COP-21 International INDCs 20 2030, compared with Global Carbon Budgets for 1.5° & 2.0°C
IPCC AR5 medium estimate 531 GtC emitted globally since mid 19th Century.
INDCs = 'ad hoc-Budget'
presented to COP-21 Dec 2015
just 2010 to 2030 sum to 272 Gt C
i.e. that's the whole global budget for 2°C!
Overall it is 83 Gt C 2010 - 2015
+ 189 Gt C 2015 - 2030
+ 198 Gt C (?) 2031 - 2100
= 470 Gt C for ~ 3 to 4° C
IPCC AR5
Carbon-Budget
310 Gt C 50%
odds for 2°C
IPCC AR5
Carbon Budget
250 Gt C 66%
odds for 2°C
IPCC/HANSEN
Carbon Budget
175 Gt C ?
odds for 1.5C
EUROPEAN UNION
1. Austria (1995)
2. Belgium (1958)
3. Bulgaria (2007)
4. Cyprus (2004)
5. Croatia (2013)
6. Czech Republic (2004)
7. Denmark (1973)
8. Estonia (2004)
9. Finland (1995)
10. France (1958)
11. Germany (1958)
12. Greece (1981)
13. Hungary (2004)
14. Ireland (1973)
15. Italy (1958)
16. Latvia (2004)
17. Lithuania (2004
18. Luxembourg (1958)
19. Malta (2004)
20. Netherlands (1958)
21. Poland (2004)
22. Portugal (1986)
23. Romania (2007)
24. Slovakia (2004)
25. Slovenia (2004)
26. Spain (1986)
27. Sweden (1995)
28. United Kingdom (1973)
GCI October 2015
CARBON BUDGET ACCOUNTING TOOL
http://cbat.info/#domain-1
14GtC
12GtC
10GtC
8GtC
6GtC
4GtC
2GtC
GtC
2010
2020
2030
2040
2050
2060
2070
2080
2090
2100
Land
Use
Change
Rus Fed
EU
USA
INDIA
CHINA
IGBP 250 Gt Budget Max for 2°C
GLOBAL CARBON BUDGET FOSSIL FUEL + LUC
HANSEN 175 Gt Budget Max for 1.5°C
IPCC 308 Gt Budget Max for 2°C

pg 28 2015 UNEP EMMISSIONS Gap Report

Box 2.1: The global carbon dioxide (CO_2) budget, non-CO_2 GHGs and the link to global warming

Limiting warming to any desired level requires a cap on total, cumulative anthropogenic CO_2 emissions. Working Group I of the IPCC (IPCC, 2013) showed that global mean temperature increases are almost directly proportional to cumulative carbon dioxide emissions since the pre-industrial period. This leads to the important conclusion that there is a maximum amount of carbon dioxide emissions, or a CO_2 budget, that can be discharged to the atmosphere over time if society wishes to stay within a 2°C or other global warming limit. The IPCC indicated that to limit warming to below 2°C with a 'likely chance' (that is >66% chance) by the end of the century, about 1 000 $GtCO_2$ of CO_2 emissions remained 'in the budget' from 2011 onward* (IPCC, 2014b; Knutti and Rogelj, 2015). To keep CO_2 emissions within such a budget allowance, annual global CO_2 emissions have to become zero at some point during the 21st century. This is a geophysical requirement that applies regardless of the budget level chosen. For non-CO_2 GHGs with a shorter lifetime in the atmosphere, such as methane, the levels of emissions that are emitted per year are more important than the cumulative amount**. Reducing their annual emissions is also important to limit global mean temperature increase to low levels. Table 2.1 indicates the year of global annual emissions becoming net zero for each of the pathways considered.

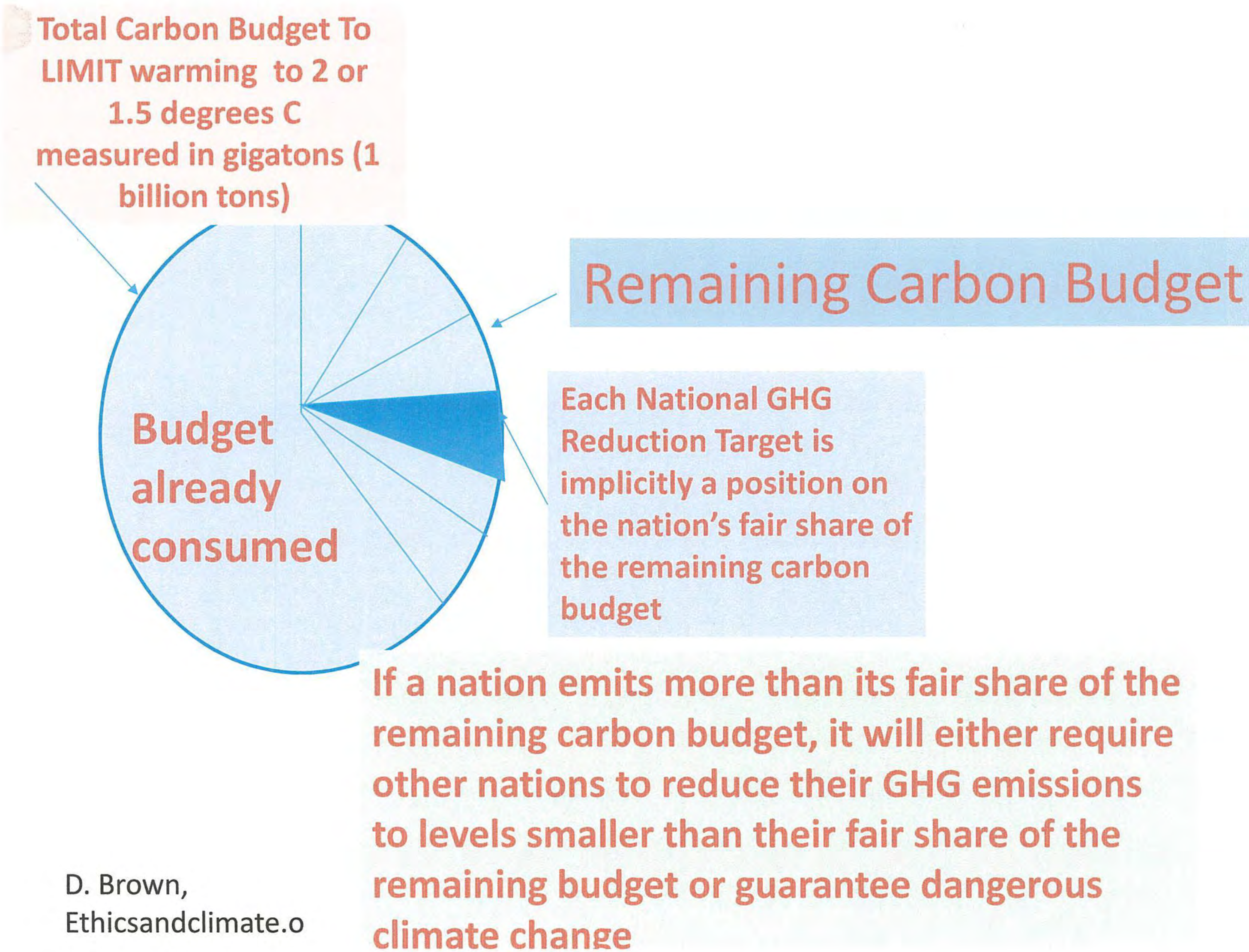
* This number is accompanied by an uncertainty range, which depends on the concurrent mitigation of non-CO_2 GHGs.
** This is approximately true, as for non-CO_2 GHGs that stay in the atmosphere for quite a while (for example, N_2O has an atmospheric lifetime of 121 years) there is also a more limited cumulative effect. See, for example, Smith *et al.* (2012).

Table 2.1: Overview of pathway characteristics of 1.5°C and 2°C scenarios based on a re-analysis of the IPCC AR5 Scenario Database and a recent study on 1.5°C scenarios[15].
All scenarios have prescribed 2020 emissions consistent with the GHG pledges made by Parties in Cancun in 2010, and hence do not represent least-cost emission levels until then. All available scenarios with limited action until 2020 rely on net negative CO_2 emissions from energy and industry during the 21st century. Most scenarios with such specifications were contributed to the IPCC AR5 Scenario Database by the LIMITS intercomparison project[16]. Note that this table provides data for limiting warming below 1.5°C and 2°C in 2100. Further information is provided in the Tables of Annex A (available online)

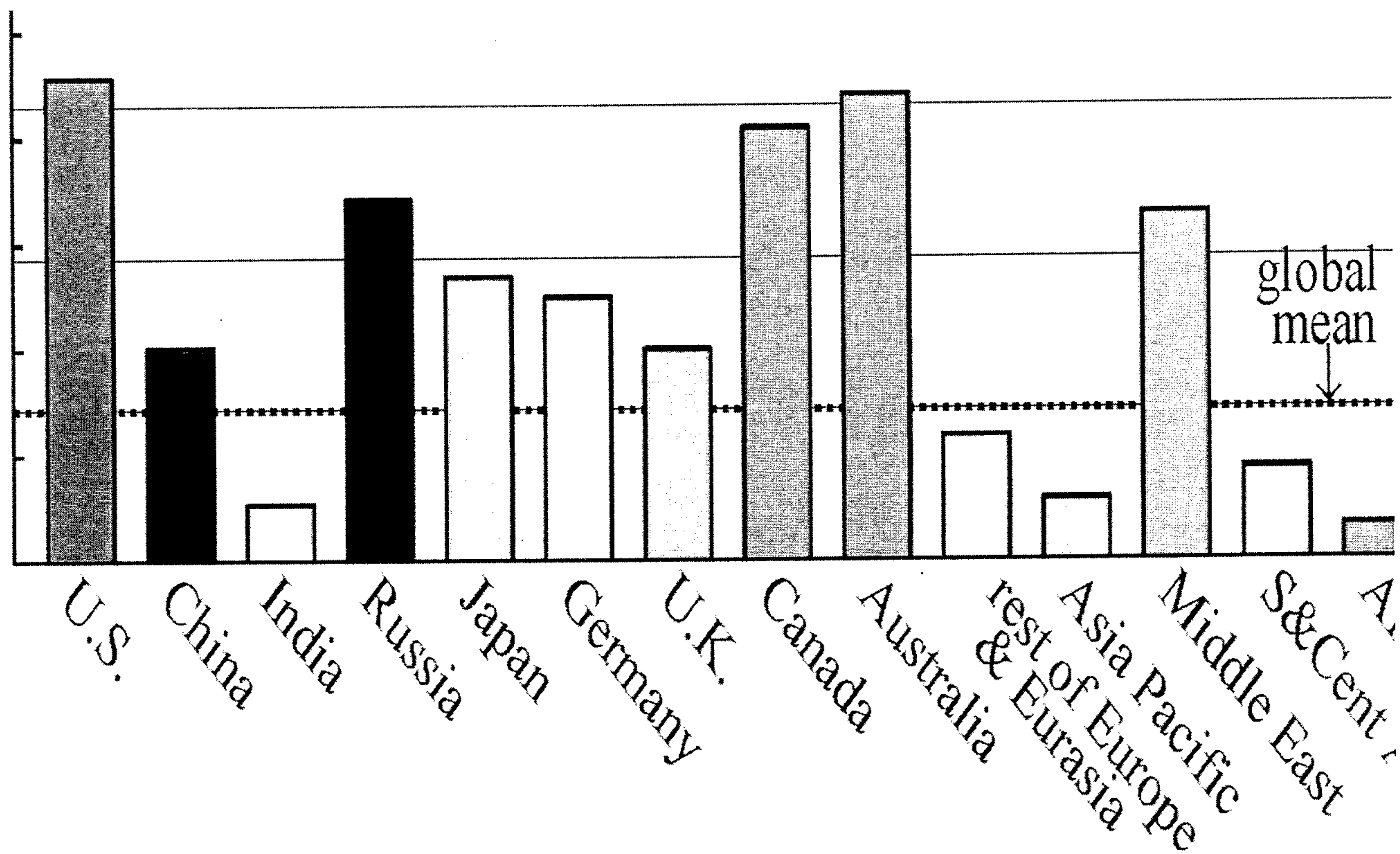
Limiting warming in 2100 (allowing for overshoot)					
1.5°C (>50% in 2100)	Pathways limiting warming to below 1.5°C by 2100 with >50% chance Limited action until 2020 and least-cost mitigation afterwards				
Number of available scenarios: 6; Number of contributing modelling frameworks: 2 Year of global annual emissions becoming net zero† for: Kyoto-GHGs: **(2060-2080)**; total CO_2 (including LULUCF): **(2045-2050)**; CO_2 from energy and industry: **(2045-2055)**					
	Annual emissions of global total greenhouse gases [$GtCO_2e$/yr]				
Year	2020	2025	2030	2050	2100
median*	**56**	**47**	**39**	**8**	**-5**
range and spread**	53(-/-)56	46(-/-)48	37(-/-)40	4(-/-)14	-5(-/-)-3
2°C (>66% in 2100)	Pathways limiting warming to below 2°C by 2100 with >66% chance Limited action until 2020 and least-cost mitigation afterwards				
Number of available scenarios: 10; Number of contributing modelling frameworks: 4 Year of global annual emissions becoming net zero† for: Kyoto-GHGs: **2085 (2080-2090)**; total CO_2 (including LULUCF): **2070 (2060-2075)**; CO_2 from energy and industry: **2070 (2060-2075)**					
	Annual emissions of global total greenhouse gases [GtCO2e/yr]				
Year	2020	2025	2030	2050	2100
median*	**52**	**48**	**42**	**23**	**-3**
range and spread**	49(49/53)55	44(46/50)53	29(31/44)44	17(18/27)29	-11(-9/-1)0
2°C (50-66% in 2100)	Pathways limiting warming to below 2°C by 2100 with 50-66% chance Limited action until 2020 and least-cost mitigation afterwards				
Number of available scenarios: 4; Number of contributing modelling frameworks: 2 Year of global annual emissions becoming net zero† for: Kyoto-GHGs: **(2095-2095)**; total CO_2 (including LULUCF): **(2065-2070)**; CO_2 emissions from energy and industry: **(2070-2080)**					
	Annual emissions of global total greenhouse gases [$GtCO_2e$/yr]				
Year	2020	2025	2030	2050	2100
median*	**53**	**50**	**47**	**28**	**-1**
range and spread**	50(-/-)55	49(-/-)51	46(-/-)48	27(-/-)29	-2(-/-)-1

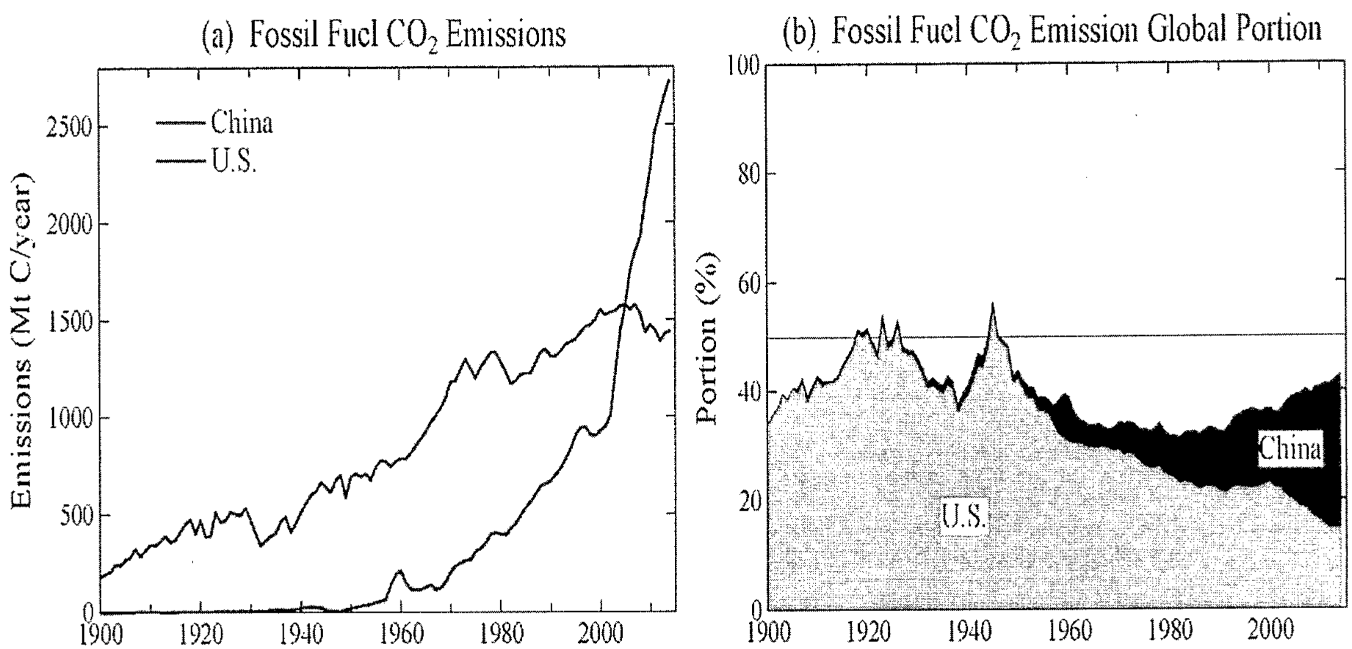
† Rounded to nearest 5 years. Explanation of format: 'median (20th percentile – 80th percentile)' – for example, '2085 (2080-2090)'; no median is provided if fewer than 10 scenarios are available '(minimum–maximum)' – for example, '(2060-2080)'.
* Rounded to the nearest 1 $GtCO_2e$/yr .
** Rounded to the nearest 1 $GtCO_2e$/yr. Explanation of format: 'minimum value (20th percentile/80th percentile) maximum value' – for example, '44(46/50)53'. No percentiles are provided if fewer than 10 scenarios are available – for example, '46(-/-)48'.

15 See Rogelj *et al.* (2015a)

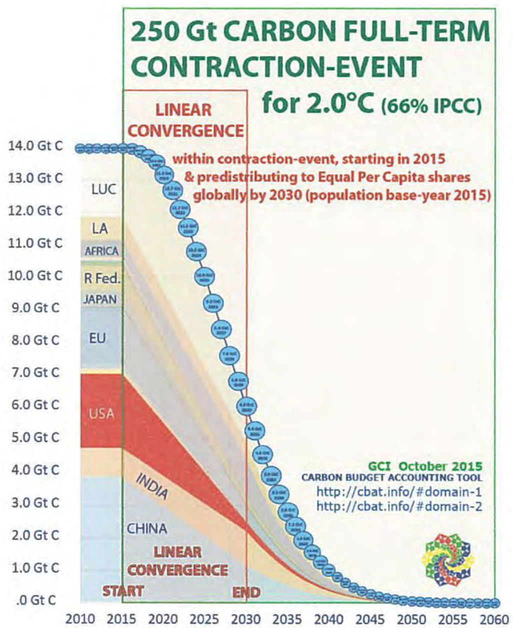


D. Brown,
Ethicsandclimate.o

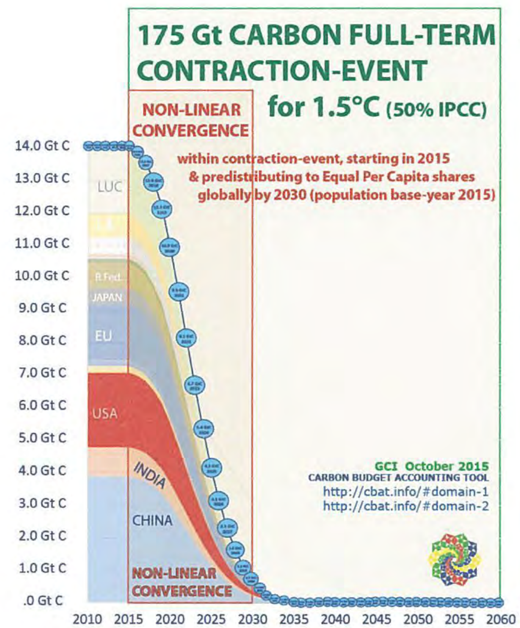

global mean
U.S.
China
India
Russia
Japan
Germany
U.K.
Canada
Australia
rest of Europe & Eurasia
Asia Pacific
Middle East
S&Cent


(a) Fossil Fuel CO_2 Emissions
China
U.S.
Emissions (Mt C/year)
0
500
1000
1500
2000
2500
1900
1920
1940
1960
1980
2000
(b) Fossil Fuel CO_2 Emission Global Portion
Portion (%)
0
20
40
60
80
100
U.S.
China
1900
1920
1940
1960
1980
2000

Emissions Reductions with contraction to equal per capita emissions in 2030



250 GtC Global	
YEAR	US
2010	2.3 Gt C
2011	2.3 Gt C
2012	2.3 Gt C
2013	2.3 Gt C
2014	2.3 Gt C
2015	2.3 Gt C
2016	2.1 Gt C
2017	2.0 Gt C
2018	1.9 Gt C
2019	1.7 Gt C
2020	1.6 Gt C
2021	1.5 Gt C
2022	1.3 Gt C
2023	1.2 Gt C
2024	1.1 Gt C
2025	.9 Gt C
2026	.8 Gt C
2027	.7 Gt C
2028	.5 Gt C
2029	.4 Gt C
2030	.3 Gt C
2031	.2 Gt C
2032	.2 Gt C
2033	.2 Gt C
2034	.1 Gt C
2035	.1 Gt C
2036	.1 Gt C
2037	.1 Gt C
2038	.1 Gt C
2039	.1 Gt C
2040	.0 Gt C
2041	.0 Gt C
2042	.0 Gt C
2043	.0 Gt C
2044	.0 Gt C
2045	.0 Gt C
2046	.0 Gt C
2047	.0 Gt C
2048	.0 Gt C
2049	.0 Gt C
2050	.0 Gt C
2051	.0 Gt C
2052	.0 Gt C
2053	.0 Gt C
2054	.0 Gt C
2055	.0 Gt C
2056	.0 Gt C
2057	.0 Gt C
2058	.0 Gt C
2059	.0 Gt C
2060	.0 Gt C
TOTAL	33.1 Gt C



175 GtC Global	
YEAR	US
2010	2.3 Gt C
2011	2.3 Gt C
2012	2.3 Gt C
2013	2.3 Gt C
2014	2.3 Gt C
2015	2.3 Gt C
2016	2.2 Gt C
2017	2.2 Gt C
2018	2.1 Gt C
2019	2.0 Gt C
2020	1.8 Gt C
2021	1.5 Gt C
2022	1.3 Gt C
2023	1.1 Gt C
2024	.9 Gt C
2025	.7 Gt C
2026	.5 Gt C
2027	.4 Gt C
2028	.3 Gt C
2029	.2 Gt C
2030	.1 Gt C
2031	.1 Gt C
2032	.0 Gt C
2033	.0 Gt C
2034	.0 Gt C
2035	.0 Gt C
2036	.0 Gt C
2037	.0 Gt C
2038	.0 Gt C
2039	.0 Gt C
2040	.0 Gt C
2041	.0 Gt C
2042	.0 Gt C
2043	.0 Gt C
2044	.0 Gt C
2045	.0 Gt C
2046	.0 Gt C
2047	.0 Gt C
2048	.0 Gt C
2049	.0 Gt C
2050	.0 Gt C
2051	.0 Gt C
2052	.0 Gt C
2053	.0 Gt C
2054	.0 Gt C
2055	.0 Gt C
2056	.0 Gt C
2057	.0 Gt C
2058	.0 Gt C
2059	.0 Gt C
2060	.0 Gt C
TOTAL	31.0 Gt C

What Should The US and Pa GHG Emissions ReductionTarget Be?

Carbon Neutral As Soon As Possible But No Later Than 2040.

This is based on converging on equal per capita shares after 2030 and achieving global reductions necessary to limit warming to 1.5 degrees. According to UNEP, the electricity and energy sector for the entire world must be carbon neutral between 2045 and 2050.

What questions should be asked of proponents of continued use of natural gas on the record.

1. How is the United States and Pennsylvania going to assure that carbon emissions are no greater than carbon sinks by no later then 2040 if governments continue to rely on natural gas?
2. Do proponents of natural gas agree that the US and Pennsylvania must as quickly as possible replace fossil fuel with non-fossil fuel to limit warming to non-dangerous levels?
3. Will proponents of continued increase use of natural gas work with the State to replace fossil fuel with non-fossil fuel as quickly as possible?

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The '2°C capital stock' for electricity generation: Committed cumulative carbon emissions from the electricity generation sector and the transition to a green economy

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HIGHLIGHTS

- Defines '2°C capital stock' as infrastructure that gives a 50% chance of 2°C warming.
- The '2°C capital stock' for electricity generation will be reached by 2017 on current trends.
- New electricity generation assets globally must then be zero carbon to avoid stranding, CCS or CDR.
- Risk of stranded assets is relevant to investors and policy makers.

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ABSTRACT

This paper defines the '2°C capital stock' as the global stock of infrastructure which, if operated to the end of its normal economic life, implies global mean temperature increases of 2°C or more (with 50% probability). Using IPCC carbon budgets and the IPCC's AR5 scenario database, and assuming future emissions from other sectors are compatible with a 2°C pathway, we calculate that the 2°C capital stock for electricity will be reached by 2017 based on current trends. In other words, even under the very optimistic assumption that other sectors reduce emissions in line with a 2°C target, no new emitting electricity infrastructure can be built after 2017 for this target to be met, unless other electricity infrastructure is retired early or retrofitted with carbon capture technologies. Policymakers and investors should question the economics of new long-lived energy infrastructure involving positive net emissions.

1. Introduction

The human population has grown over 4-fold from 1.65 billion in 1900 to over 7 billion today [1,2]. Over a similar period, world average per capita output has increased almost 6-fold from ~\$1300 in 1900 to ~\$7600 in 2008 real GDP in 1990 US dollars [3]. This remarkable achievement has been accompanied by significant increases in pressure on the natural environment, and it is accordingly suggested that the current geological era be termed the 'Anthropocene' [4]. Humans may now be confronting 'planetary boundaries' [5]. Environmental concerns have been presented in the past, coupled with calls to arrest economic growth [6–8]. So far, price signals have triggered demand efficiencies, substitution, new supplies and new technologies that have moderated concerns about resource scarcity [9]. However, accurate price signals are absent for climate change and other natural capital such as biodiversity and fisheries. The trends are highly adverse, particularly on climate change [10,11]. Electricity generation (and heating) currently contributes approximately 25% of global anthropogenic greenhouse gas emissions, the main driver of observed climate change [12]. A global transition to clean electricity generation is therefore anticipated [13] and necessary to curtail future climate impacts. How rapid does this transition need to be for reasonable odds of limiting temperature increases to safe levels?

There are two critical inertias associated with addressing climate change that create two stock problems. First, built infrastructure in the energy sector is characterised by long lifetimes. In the EU, for example, approximately 29% of thermal power plant

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capacity is over 30 years old and 61% over 20 years old [14]; today's energy infrastructure even includes assets constructed over 50 years ago.[1] Energy sector investments made today are likely to be operating and emitting carbon dioxide (CO_2) for decades into the future. Building on Davis et al. [15], Davis and Socolow [16] [DS] advance a methodology for estimating these future emissions from energy sector assets, which we refer to as 'committed cumulative carbon emissions' (CCCE). An implication of this inertia for policy-makers is that greater focus should be upon investments in long-lived infrastructure, such as coal mines, oil and gas fields and power plants, than upon the operation of existing assets.

Second, the climate system has its own inertia. CO_2 emissions remain resident in the atmosphere for centuries and it is the *stock* of atmospheric CO_2 that affects temperatures, rather than the *flow* of emissions in any given year [17]. Many of the expected economic damages from climate change depend on peak warming, and peak warming is a function of cumulative carbon emissions ('CCE') (e.g. [18,19]). In recent years some policy makers have acknowledged the existence and implications of carbon budgets (e.g. [20]). Nevertheless, it remains common practice for policy-makers to focus on annual CO_2 emission reduction targets – such as reducing emissions by 40% by 2030 [21] – which are only indirectly relevant to the core objective of limiting the cumulative stock of carbon in the atmosphere.

This paper introduces the concept of a '2°C capital stock' for the electricity sector by combining DS's concept of CCCE with Allen et al.'s concept of a cumulative carbon budget. We define the '2°C capital stock' as the stock of infrastructure that implies future emissions consistent with a 50% probability of a peak global mean temperature increase of 2°C or less. By making use of integrated assessment model (IAM) scenarios of energy system transitions, we calculate the date at which the installed electricity infrastructure reaches the 2°C capital stock.

The implications for energy policy of this concept are significant. Once the 2°C capital stock for the electricity sector has been reached, all new additions to the stock of generating infrastructure need to be net zero emissions to meet the 2°C target with 50% probability, without subsequent large-scale deployment of carbon capture technologies[2] or without the premature stranding of energy sector assets.

Our core result is that for a 50% probability of limiting warming to 2°C, assuming other sectors play their part, *no new investment in fossil electricity infrastructure (without carbon capture) is feasible from 2017 at the latest*, unless energy policy leads to early stranding of polluting assets or large scale carbon capture deployment. If other sectors remain on business as usual rather than a 2°C consistent pathway, even a stranding (i.e. premature retirement) of the entire global fossil fuel electricity generating capital stock today would not be sufficient to provide a 50% probability of limiting increases to 2°C. The paper highlights a set of choices for policy-makers: they can either (a) ensure that all new electricity generation investment is zero carbon from 2017, or (b) make major investments in retrofitting carbon capture technologies, which is at present expensive and uncertain to deliver at cost and at scale, (c) be prepared to strand substantial parts of the built fossil energy infrastructure, (d) invest heavily in negative emissions technologies, or (e) abandon the 2°C stabilisation goal and accept the substantial risks of dangerous climate change and the knock-on impacts [11].

This paper builds upon earlier research on committed emissions. Davis et al. [15] calculated committed cumulative emissions from combustion of fossil fuels by existing infrastructure between 2010 and 2060 and find that the capital stock in 2010 entailed a commitment to a warming around 1.3°C above the pre-industrial era. Guivarch and Hallegatte [23] build upon these results by including non-CO_2 greenhouse gases and inertia in transportation infrastructure to conclude that future climate policies need to consider existing polluting infrastructure if the 2°C stabilisation goal is to be met. Lecocq and Shalizi [24] conclude that mitigation policy should be targeted towards countries where long-lived infrastructure is being built at a rapid rate. Bertram et al. [25] find that under less stringent near-term policies, most of the near-term emissions come from additional coal-powered generation capacity and conclude that significant coal capacity would have to be retired in the future to meet warming targets. Johnson et al. [26] find that the timing and rate of the complete phase-out of coal-based electricity generation without CCS will depend mostly on the strength of near-term climate policies. They conclude that an effective strategy for reducing stranded capacity is to minimize new construction of coal capacity (without CCS) in the first place. Finally and perhaps most notably, the International Energy Agency reports in its 2012 World Energy Outlook that "...infrastructure in existence in 2017 and expected to continue to operate through to 2035 would emit all the cumulative emissions allowed in the 450 Scenario" ([27]; p. 265). This paper goes beyond the IEA in that we not only use the full variety of models and scenarios from the Intergovernmental Panel on Climate Change (IPCC), we also extend the analysis to 2100, present results for 1.5°C and 3°C carbon budgets, and further test the sensitivity of the results for the 2°C capital stock to a range of different assumptions and scenarios. Results of the analysis in this paper reinforce these previous findings.

The problems created by 'committed' emissions are also related to the concept of 'carbon lock-in', which is defined as "the tendency for certain carbon-intensive technological systems to persist over time, 'locking out' lower-carbon alternatives" [28]. For example, Unruh [29] explored how the barriers to the scale-up of low carbon alternatives created path-dependent increasing returns to scale in the fossil energy sector. Kalkuhl et al. [30] show that market imperfections may trigger lasting dominance of one technology over another for several decades, even if that other technology is more efficient.

Our paper adds to the existing body of literature and extends the existing research by adding future emissions from all sectors as projected in the IPCC 5th Assessment Report [IPCC AR5] scenarios. Focusing on long-lived committed CO_2 emissions, we calculate not only the remaining carbon budgets in 2014 for the polluting electricity generating capital stock but also the year in which the remaining budget will be exhausted. This paper assesses the impact of different levels of mitigation ambition in other sectors across the economy and the simplicity of our approach allows us to identify some of the key features that matter for the lock-in of polluting electricity generating infrastructure.

The paper is structured as follows. Section 2 sets out the data sources employed in the analysis and the methodologies used to analyse the data. Section 3 discusses the results and sensitivities of our analysis. Finally, Section 4 examines the policy choices and the implications for policymakers and investors.

2. Methods

To assess when the capital stock consistent with a 50% chance of limiting global warming to 2°C is reached, three elements are

[1] E.g. the 'Alpena Huron 07' subcritical coal generator in Alpena, MI (online since 1955 – 60 years) or the 'Anan 1' subcritical oil generator in Anan City, Japan (online since 1963 – 52 years) which are both still in operation according to the June 2015 version of the Platts WEPP database.

[2] Carbon capture technology in this context could include new or retrofitted electricity sector carbon-capture-and-storage (CCS) as well as technologies that remove CO_2 from the ambient air, commonly referred to as carbon dioxide removal (CDR) technologies [22].

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required: (1) total cumulative carbon budgets consistent with the latest climate science for multiple peak warming thresholds and at different probabilities; (2) historical and projected committed future cumulative emissions from electricity generation and (3) projections for future emissions from all sectors.

The following subsections detail our methods in each of these areas. Section 2.1 details estimates of the carbon budget for different peak warming and probability threshold combinations. Section 2.2 describes assumptions for the evolution of the committed cumulative emissions from the electricity generation capital stock. Section 2.3 describes scenarios for the future realised emissions from different sectors.

2.1. Remaining carbon budget and treatment of short-lived climate pollutants

The analysis in the current paper is solely focused on long-lived CO_2 emissions. While the emissions of short-lived climate pollutants (SLCPs), notably methane and black carbon, also provide a radiative forcing on the climate system, long-term temperature stabilization (over the timescale of centuries) is largely a function of the cumulative stock of long-lived greenhouse gases (GHGs), predominantly CO_2, when global net emissions of long-lived gases fall to zero [17]. The contribution of SLCPs to peak warming is a function of their rate of emission at the time when net emissions of long-lived GHGs reach zero [31]. If emissions of SLCPs were then stopped completely, their contribution to long-term irreversible warming would eventually decay to zero, unlike CO_2, from which warming persists for centuries. Due to the essentially irreversible impact of CO_2 emissions on the climate system, we focus our analysis on the risk of locking in irreversible temperature change via committed future cumulative emissions of CO_2 from infrastructure being built over the next few decades. When thinking about temperature changes at specific times over the 21st century, SLCP-induced warming will have an important role to play and the impact of different SLCP mitigation choices needs to be fully considered alongside CO_2 [32].

Estimates of cumulative CO_2 emission budgets depend on the magnitude of peak warming and probability of restricting warming to beneath this value (due to uncertainty in the physical climate response) being considered. We take estimates for multiple peak warming thresholds at multiple probabilities from Table 2.2 of the IPCC 5th Assessment Synthesis Report [33], summarised in Table 1. These carbon budgets assume a contribution to peak warming from SLCPs consistent with the RCP8.5 high emissions scenario [34]. The probability thresholds given here correspond to percentiles of the CMIP5 Earth System Model distribution and are not equivalent to the calibrated likelihood statements of IPCC Working Group 1 [35] as those calibrated likelihood statements also assess uncertainty not captured by the models. To calculate historical emissions, we use 2011 cumulative emissions from IPCC AR5 WG1 (515GtC) updated with emissions data for 2011–2013 from the Global Carbon Budget 2014 [36].

For our analysis we focus mainly on a budget to achieve $\leqslant 2°C$ peak warming with a 50% probability. For peak warming of 2°C the remaining budget is 322GtC (1184GtCO$_2$). The budget varies between 77GtC (284GtCO$_2$) for <1.5°C (66% probability) and 853GtC (3134GtCO$_2$) for <3°C (33% probability).

Table 1
2011 and 2014 remaining cumulative carbon budgets for different peak warming and probability thresholds. Data and information are taken from Table 2.2 of [33] with cumulative emissions between 2011 and 2013 calculated from Le Quéré et al. [36].

	Warming[b]	Likelihood[c] (%)	Budget (CCE)[d] in 2011	Emitted (CCE) 2011–2013	Budget (CCE)[d] in 2014
[GtCO$_2$]	<1.5°	66	400	116	284
		50	550	116	434
		33	850	116	734
	<2.0°	66	1000	116	884
		50	1300	116	1184
		33	1500	116	1384
	<3.0°	66	2400	116	2284
		50	2800	116	2684
		33	3250	116	3134
[GtC][a]	<1.5°	66	109	32	77
		50	150	32	118
		33	231	32	200
	<2.0°	66	272	32	241
		50	354	32	322
		33	408	32	377
	<3.0°	66	653	32	622
		50	762	32	731
		33	885	32	853

[a] Conversion factor: 1GtC = 3.664GtCO$_2$.
[b] Warming due to CO_2 and non-CO_2 drivers. Temperature values are given relative to the 1861–1880 period.
[c] Fractions of scenario simulations meeting the warming objective with that amount of CCE.
[d] CCE at the time the temperature threshold is exceeded that are required for 66%, 50%, and 33% of the simulations assuming non-CO_2 forcing follows the RCP8.5 scenario (similar emissions are implied by the other RCP scenarios). For the most scenario–threshold combinations, emissions and warming continue after the threshold is exceeded. Nevertheless, because of the cumulative nature of the CO_2 emissions these figures provide an indication of the cumulative CO_2 emissions implied by simulations under RCP-like scenarios. Values are rounded to the nearest 50.

2.2. The CCCE of electricity infrastructure

Using emission intensity and generation data from 2009 (CARMA database; see www.carma.org), DS analyse the currently existing polluting electricity infrastructure and find that *new* fossil fuel power plants (i.e. oil, coal, and gas) built in 2012 will alone cumulatively emit approximately 5.2GtC if their average lifetime is 40 years. The corresponding estimate of 'committed' emissions from *all* fossil fuel power plants operating in 2012 is 84GtC.[3]

DS not only analyse the currently existing capital stock of polluting electricity infrastructure, but also how this capital stock has developed in the past. New coal-fired power plants continue to be built, and "more have been built in the past decade than in any previous decade."[4] According to their calculations, "worldwide, an average of 89 gigawatts per year (GWyr^{-1}) of new coal generating capacity was added between 2010 and 2012, 23GWyr^{-1} more than in the 2000–2009 time period and 56GWyr^{-1} more than in the 1990–1999 time period."[5] Overall they conclude that the world's committed emissions from electricity infrastructure have grown by approximately 4% p.a. over the last decade.

Much of that accelerated growth over the past decade comes from the renaissance of coal (described e.g. by Steckel et al. [37]) and given the current pipeline of planned coal-fired power stations, our central scenario assumes a continuation of 4% p.a. growth in committed cumulative emissions from the electricity capital stock in the coming decades. We examine sensitivities to this growth rate in the range 0–7% p.a. An exponential growth pathway of committed cumulative emissions is likely to be unrealistic in the long run. However, given planned investments over the next decade and the limited time remaining until the 2°C capital

[3] According to DS and depending on the assumed average lifetime of energy infrastructure, committed emissions in 2012 vary from 26.8GtC (20 years lifetime) up to 157.5GtC (60 years lifetime).
[4] Davis and Socolow [16], p.1.
[5] Ibid.

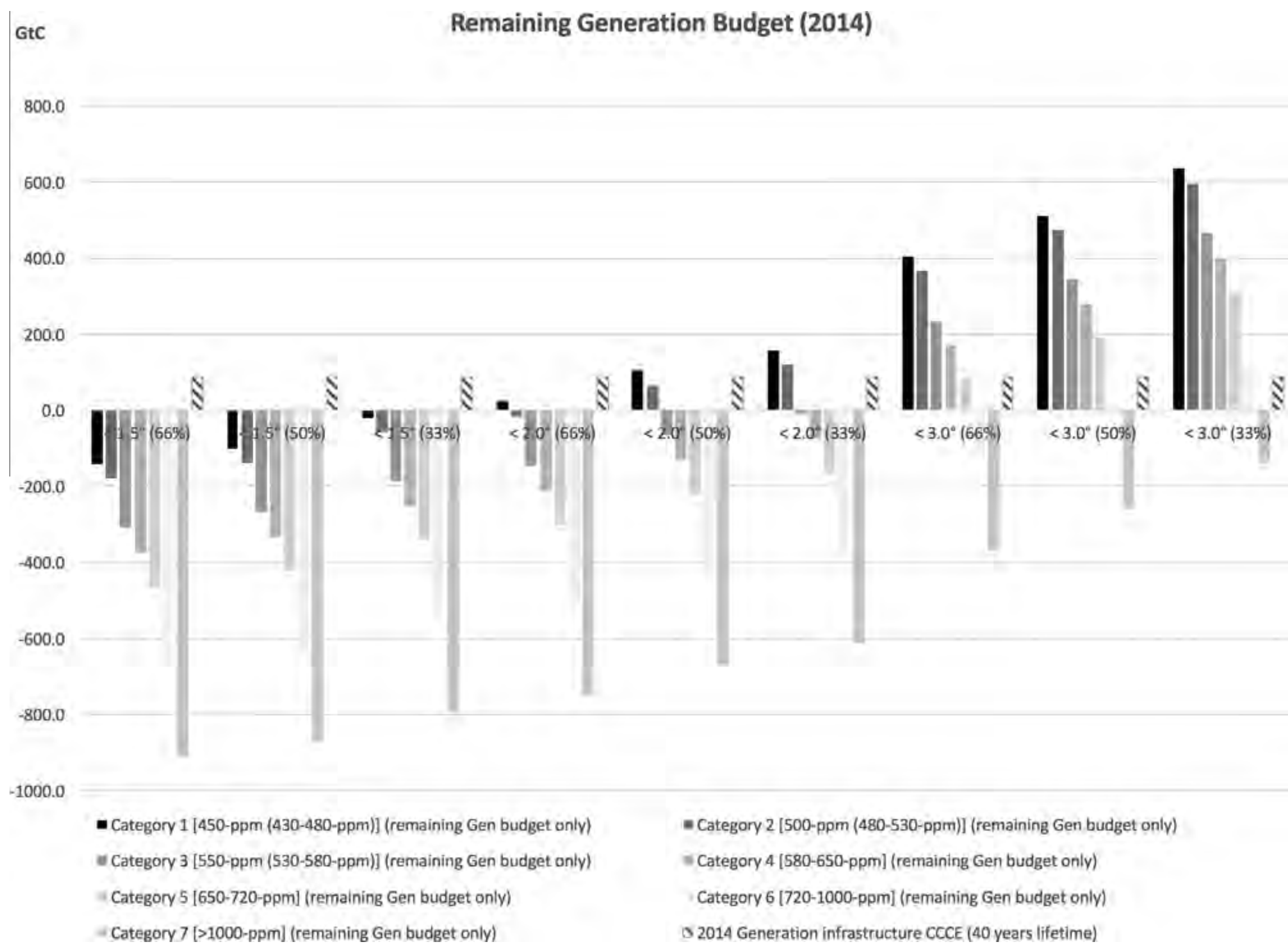

Fig. 1. Remaining 2014 carbon budget for electricity generation, for different peak warming magnitudes and probabilities, decomposed by groupings of emissions pathways (denoted by scenario 2100 concentrations). The 2014 CCCE from electricity generation infrastructure (40 years lifetime) is shown by the hatched bar for each case.

stock is reached, these growth assumptions remain broadly plausible in the relatively short timeframes under consideration.

2.3. Future realised emissions

The electricity sector is not the only source of CO_2 emissions within the economy. Industry, land-use, transport and other non-electricity sectors also contribute to global emissions. Given an overall cumulative emissions budget, cumulative emissions across the century from other sectors reduce the cumulative emissions that can be emitted from the electricity sector.

For ranges of possible scenarios of cumulative emissions from other sectors, we use the IAM database compiled for IPCC AR5 WG3.[6] IAM scenarios aim to find a cost-optimal energy system transition to meet a goal for CO_2-equivalent (incorporating the impacts of some non-CO_2 climate forcing agents) atmospheric concentrations in 2100, given certain constraints on policy action and technological availability [38]. IAMs are highly idealised and often assume globally coordinated policy action that can start immediately. These emission scenarios are not harmonised – in other words, different scenarios have different assumed histories over 2005–2015 that can be different to the actual historical emissions. However, the spread of different scenarios gives a range of futures for 21st century cumulative emissions from sectors other than electricity generation under varying degrees of climate policy ambition.

In these scenarios, the emission pathways in the different sectors are highly connected to each other. Thus, in any given scenario, the budget remaining for electricity generation emissions (after accounting for emissions from the other sectors) is itself a function of the electricity generation emissions assumed in that scenario. The endogenous nature of the power sector increases the complexity of comparative scenario analysis. In order to explore the year in which the 2°C electricity generation capital stock is reached under different assumptions, we consider different (exogenous) rates of growth in future emissions from the electricity generation, holding other features of the scenarios constant. Results are reported below in our sensitivity analyses. It is also notable that in many scenarios, emissions from non-electricity sectors have not reached zero in 2100, our cut-off year. As we do not account for post-2100 emissions from these sectors, our calculations for the remaining emissions budget for electricity generation is likely to be an overestimate.

Scenarios can be grouped by their 2100 CO_2-eq atmospheric concentration [41]. Scenarios with 2100 concentrations in the range 430–480-ppm correspond to an IPCC assessed *likely* (>66%) probability of warming in the 21st century remaining beneath 2°C, when assessed under representative climate response uncertainty [12]. 480–530-ppm scenarios correspond to >50% probability (when concentrations do not overshoot 530-ppm) and to <50% probability when overshoots do occur. All other scenario groupings for higher 2100 concentrations are consistent with successively less likely probabilities of limiting warming to beneath 2°C.

We use these scenarios for estimates of emissions from sectors other than electricity generation across the century but also for estimates of *realised* electricity generation emissions over time. In the near-term, there are very small differences between

[6] Found at https://tntcat.iiasa.ac.at/AR5DB/dsd?Action=htmlpage&page=about.

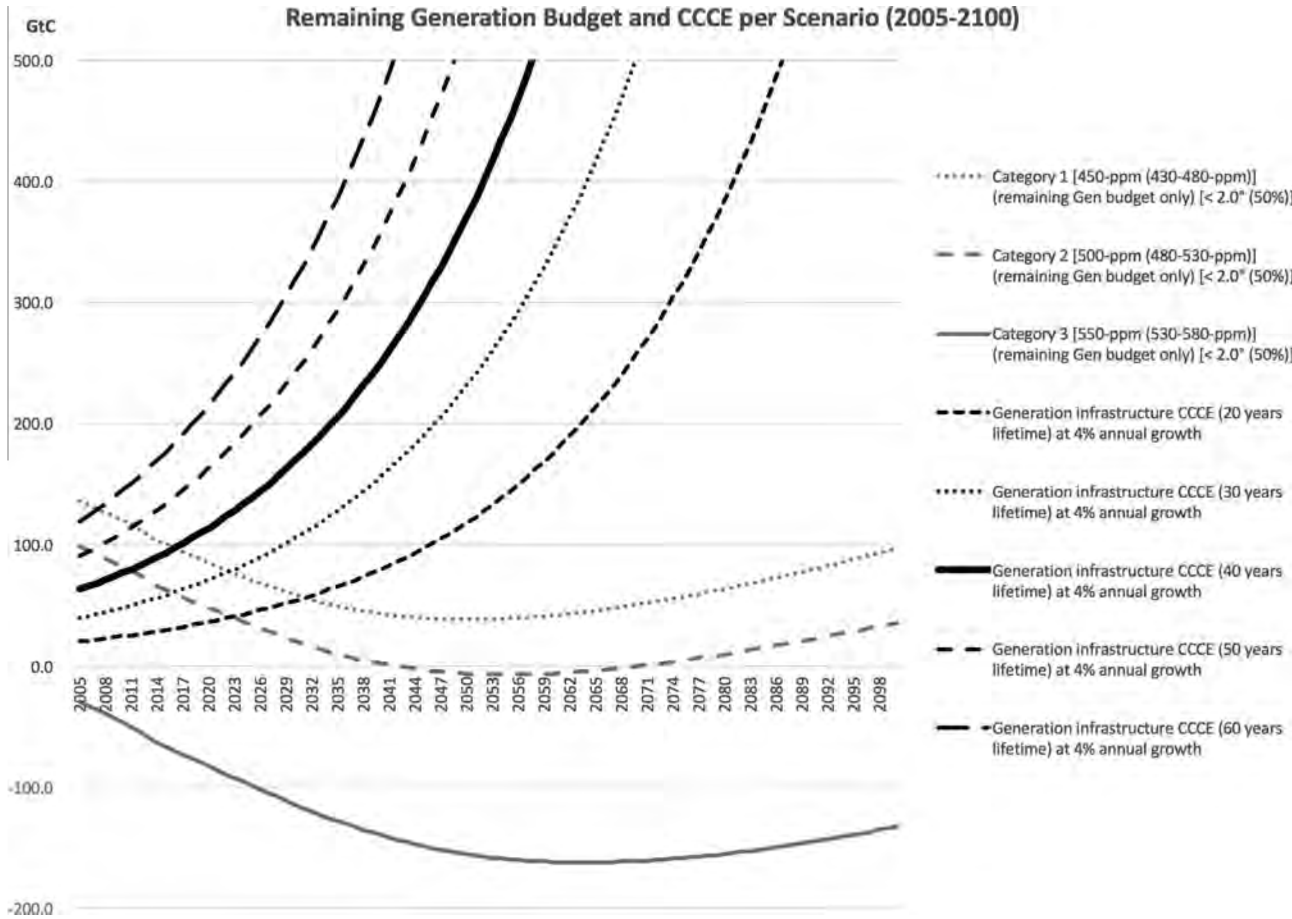

Fig. 2. Future development of CCCE from electricity infrastructure (assuming different lifetimes and a 4% growth p.a.) and remaining generation budget for 430–580-ppm pathways, 2005–2100, assuming a ⩽2°C (50% probability) overall budget.

scenarios in the degree to which realised emissions reduce the size of the remaining carbon budget. This is despite likely significant differences in electricity sector investments and partially reflects the inertia of realised emissions to previously locked-in emissions. However, a useful area for further work would be to enable the committed cumulative emissions to be calculated directly from the reported IAM output for a given emission scenario, in order to more precisely capture the relationship between growth in committed and realised emissions in electricity generation and other sectors.

3. Results

3.1. Remaining electricity sector cumulative emissions budget in 2014

Using the scenarios described in Section 2.3, it is possible to assess the present-day (2014) remaining carbon budgets for electricity generation, dependent on the level of ambition of future mitigation in non-electricity sectors. As shown in Fig. 1, if future emissions from all sectors follow the mean of the 430–480-ppm scenarios, and today's electricity infrastructure has an average lifetime of 40 years, by 2014 we were already committed to 87% (or 136% for 480–530-ppm non-electricity pathways) of the remaining 2014–2100 electricity generation budget for a 2°C peak warming target with 50% probability through existing infrastructure. For a ⩽2°C goal (33% probability), more than half (57%) (or 75% for 480–530-ppm) of the remaining electricity generation budget has already been committed. Mean transition pathways in the non-electricity sectors that are less ambitious than the 430–480 ppm and 480–530 ppm groupings are likely to entail that the 2°C electricity capital stock has already been reached. Too much carbon emitting electricity capital stock has already been installed to be consistent with a peak warming goal more ambitious than 2°C with 66% probability, irrespective of the non-electricity emissions pathway.

3.2. Commitment year for 2°C (50% probability) electricity infrastructure capital stock

Assuming committed cumulative emissions from the electricity sector continue to increase at 4% p.a. (following DS and Tidball et al. [40]) the date at which the electricity sector 2°C capital stock can be calculated, dependent on the alternative futures of realised emissions. As shown by the solid black line in Fig. 2, if all other emissions follow a mean scenario consistent with overall 2100 430–480-ppm concentrations, we will have built the electricity generating capital stock consistent with a ⩽2°C (50% probability) budget, by 2017. Such a scenario implies very significant mitigation action in all sectors, and even if this could be realised, all new electricity capital would have be to zero carbon by 2017, or rely on future carbon capture technology in order to remain consistent with an overall ⩽2°C (50% probability) budget.

If emissions from other sectors are only slightly higher, following a 480–530-ppm path instead of a 430–480-ppm path, the 2°C electricity capital stock was installed in 2011. If realised emissions in all sectors follow pathways consistent with concentrations above 530-ppm, new electricity generating assets needed to be

Table 2
Year in which generation budget is committed (assuming 40 years lifetime and 4% growth p.a.) for mean realised emissions scenario groupings and peak warming budgets (bold years are future years, after 2015).

Lifetime of capital stock 40 years at 4% annual growth					Year of budget commitment (2006–2100)[e]						
	Warming[a]	Likelihood[b] (%)	Budget (CCE)[c] in 2014	Committed CCE[d] in 2014	Cat. 1 450-ppm (430–480-ppm)	Cat. 2 500-ppm (480–530-ppm)	Cat. 3 550-ppm (530–580-ppm)	Cat. 4 580–650-ppm	Cat. 5 650–720-ppm	Cat. 6 720–1000-ppm	Cat. 7 >1000-ppm
[GtC]	<1.5°	66	77	90	<2006	<2006	<2006	<2006	<2006	<2006	<2006
		50	118	90	<2006	<2006	<2006	<2006	<2006	<2006	<2006
		33	200	90	<2006	<2006	<2006	<2006	<2006	<2006	<2006
	<2.0°	66	241	90	<2006	<2006	<2006	<2006	<2006	<2006	<2006
		50	322	90	**2017**	2011	<2006	<2006	<2006	<2006	<2006
		33	377	90	**2024**	**2019**	<2006	<2006	<2006	<2006	<2006
	<3.0°	66	622	90	**2048**	**2045**	**2032**	**2025**	2013	<2006	<2006
		50	731	90	**2055**	**2053**	**2042**	**2036**	**2027**	<2006	<2006
		33	853	90	**2062**	**2059**	**2051**	**2045**	**2038**	**2017**	<2006

[a] Warming due to CO_2 and non-CO_2 drivers. Temperature values are given relative to the 1861–1880 period.
[b] Fractions of scenario simulations meeting the warming objective with that amount of CCE.
[c] CCE at the time the temperature threshold is exceeded that are required for 66%, 50%, and 33% of the simulations assuming non-CO_2 forcing follows the RCP8.5 scenario (similar emissions are implied by the other RCP scenarios). For the most scenario–threshold combinations, emissions and warming continue after the threshold is exceeded. Nevertheless, because of the cumulative nature of the CO_2 emissions these figures provide an indication of the cumulative CO_2 emissions implied by simulations under RCP-like scenarios.
[d] Only electricity generation capital stock based on Davis and Socolov [3]: CCCE of 307GtCO_2 (84GtC) in 2012 growing by 4% p.a. (assuming a 40 year lifetime).
[e] Year of budget commitment is the year in which enough electricity generation capital stock is built to consume remaining budget for only electricity generation.

zero carbon long ago to meet the 2°C (50% probability) target (see Table 2). These findings are largely consistent with existing integrated assessment literature (reviewed e.g. in Krey [39]) examining the question of delayed action on climate change mitigation. If electricity sector mitigation is delayed, the 2°C target will be hard to achieve due to the locked in emissions from the existing energy infrastructure.

As shown in Table 2, even in the most stringent IPCC scenarios we have already committed to more electricity generation emissions with today's infrastructure than any scenario contains which would give us a realistic chance to 1.5°C global warming. Meeting a 1.5°C target without CCS or asset stranding would have required that all additions to the electricity sector were zero carbon from 2006 onwards, at the latest.

3.3. Sensitivity of results

The year at which the 2°C electricity capital stock is reached depends on a number of assumptions. The assumptions for future cumulative carbon emissions from non-electricity sectors have a significant effect on the remaining budget for electricity, and hence upon the point in time at which committed emissions from the electricity sector imply temperature increases of 2°C. While we use the different IPCC scenarios and models to cover a wide range of possible non-electricity sector emissions in our approach, this section tests the sensitivity of our results towards other relevant assumptions. In particular, we test the sensitivity of our results towards: (1) the assumed lifetime of polluting electricity-generating infrastructure; (2) the annual growth rate of CCCE; (3) the influence of CCS in later decades of this century on the remaining carbon budgets; and (4) the variance of emissions pathways within a certain IPCC ppm range.

3.3.1. Lifetime of polluting capital stock

Fig. 2 shows the development of CCCE from the electricity sector under different assumed plant lifetimes. For all realised emissions pathways a reduction (or increase) of the mean lifetime of power plants has significant impact on the commitment year.

If, for example, the average economic lifetime of existing and future fossil-fuelled power plants could be reduced from 40 to 30 years, the commitment year for the 2°C (50% probability) capital stock would be between 2016 (480–530-ppm pathways) and 2023 (430–480-ppm pathways) instead of 2011–2017. Table 3 shows an overview of commitment years under the 30 years lifetime assumption for all budgets and scenarios. Given that historically the average economically useful life of electricity generating infrastructure is 40 years [40,16], this would imply stranding assets 10 years before the end of their useful life.

When generating capacity is prematurely retired, the type of replacement plant is highly relevant. Coal to gas substitution may not, for instance, reduce CCCE. As discussed further below, if coal-fired generation capacity is replaced immediately by new CCGTs with 40-year lifetimes, CCCE may actually be higher than if the coal-fired plant were instead replaced later, at the end of its economic life, with zero carbon generation.

3.3.2. Different growth rates of polluting capital stock

Fig. 3 shows the development of CCCE of generation capital stock under different growth assumptions. Given the short time until the expected commitment year, only dramatic reductions of the annual growth rate of CCCE can have a meaningful impact. In the analysed scenarios of 430–530-ppm pathways, a small reduction in the growth rate has an insignificant impact on the commitment year. If, for example, the annual growth rate of existing and future generation CCCE could be reduced from 4% to 3% p.a., the relevant years for the 2°C (50% probability) capital stock remain

Table 3
As for Table 2 but assuming a 30 year mean lifetime of existing electricity sector generation stock (bold years are future years, after 2015).

Lifetime of capital stock 30 years at 4% annual growth					Year of budget commitment (2006–2100)[e]						
	Warming[a]	Likelihood[b] (%)	Budget (CCE)[c] in 2014	Committed CCE[d] in 2014	Cat. 1 450-ppm (430–480-ppm)	Cat. 2 500-ppm (480–530-ppm)	Cat. 3 550-ppm (530–580-ppm)	Cat. 4 580–650-ppm	Cat. 5 650–720-ppm	Cat. 6 720–1000-ppm	Cat. 7 >1000-ppm
[GtC]	<1.5°	66	77	56	<2006	<2006	<2006	<2006	<2006	<2006	<2006
		50	118	56	<2006	<2006	<2006	<2006	<2006	<2006	<2006
		33	200	56	<2006	<2006	<2006	<2006	<2006	<2006	<2006
	<2.0°	66	241	56	2009	<2006	<2006	<2006	<2006	<2006	<2006
		50	322	56	**2023**	**2016**	<2006	<2006	<2006	<2006	<2006
		33	377	56	**2032**	**2026**	<2006	<2006	<2006	<2006	<2006
	<3.0°	66	622	56	**2060**	**2056**	**2041**	**2032**	**2019**	<2006	<2006
		50	731	56	**2068**	**2065**	**2053**	**2045**	**2034**	<2006	<2006
		33	853	56	**2074**	**2072**	**2062**	**2056**	**2046**	**2023**	<2006

[a] Warming due to CO_2 and non-CO_2 drivers. Temperature values are given relative to the 1861–1880 period.
[b] Fractions of scenario simulations meeting the warming objective with that amount of CCE.
[c] CCE at the time the temperature threshold is exceeded that are required for 66%, 50%, and 33% of the simulations assuming non-CO_2 forcing follows the RCP8.5 scenario (similar emissions are implied by the other RCP scenarios). For the most scenario–threshold combinations, emissions and warming continue after the threshold is exceeded. Nevertheless, because of the cumulative nature of the CO_2 emissions these figures provide an indication of the cumulative CO_2 emissions implied by simulations under RCP-like scenarios.
[d] Only electricity generation capital stock based on Davis and Socolov [16]: CCCE of 307GtCO_2 (84GtC) in 2012 growing by 4% p.a. (assuming a 30 year lifetime).
[e] Year of budget commitment is the year in which enough electricity generation capital stock is built to consume remaining budget for only electricity generation.

as before, namely between 2011 (480–530-ppm pathways) and 2017 (430–480-ppm pathways). Table 4 shows an overview of commitment years under the 3% p.a. growth assumption for all budgets and scenarios.

This insensitivity is due to the large already existing commitments from the energy sector compared to the ⩽2°C (50% probability) budget (87%, see Fig. 1). Even a significant structural change in future investments in this capital stock would, without a premature shut-down of polluting capacity, only marginally affect the relevant 'cut-off' year. For instance, under the assumption of a 7% p.a. growth rate, the commitment year is only slightly earlier. Under the assumption of 0% annual growth of CCCE (i.e. new investment in polluting generation capacity only replaces retiring capacity), the remaining generation budget is still used up in the early 2020s (see Table 8).

3.3.3. Sensitivity to carbon capture technology assumptions

Assuming realised emissions from all sectors consistent with 430–480 ppm scenarios, new generating infrastructure has to be net zero carbon by 2017. This finding does not imply that no new fossil generation investment is possible from 2017 onwards. It implies that any new committed fossil emissions from 2017 must be eliminated by incorporating carbon capture, offset by retrofitting carbon capture for existing infrastructure or by carbon dioxide removal (CDR) technologies to remove the same amount of cumulative carbon from the atmosphere as the newly built infrastructure will emit over its lifetime.

IPCC scenarios that assume more carbon capture tend to involve greater near-term emissions (precisely because the capture technologies operate in the future). This implies a *lower* available near-term budget for electricity generation, which moves the date of the 2°C capital stock (with assumed CCS in the future) earlier in time. Carbon capture deployment is particular prevalent in the 430–530-ppm groupings.

Table 5 shows the calculations under the assumption that CCS has no significant impact to 2100. In scenarios in which no CCS is deployed new power plants must be net zero several years later (2019–2029). This is explained by the fact that a 430–530-ppm consistent pathway without CCS (which primarily affects the electricity sector) requires stronger and faster decarbonisation in sectors other than electricity generation. As a consequence, there is a larger share of cumulative carbon budget available for electricity generation, which hence has more time before reaching the 2°C capital stock.

Similarly, in scenarios in which significant CCS is deployed, we find that the 'cut-off' date moves closer to the present (Table 6). Assuming that CCS will capture most of the emissions from generating infrastructure in future decades of this century would require committed emissions to stop growing by 2010 (480–530-ppm pathways) and by 2016 (430–480-ppm). Scenarios that assume that most of the electricity sector emissions will be captured in later decades of the century allow for a slower decarbonisation of other sectors and hence leave less generation budget to the electricity sector today.

In nearly all 430–530-ppm scenarios, CCS plays an important role. Only 7 scenarios from the 430 to 480-ppm pathways assume no CCS between 2005 and 2100 (108 scenarios assume CCS) and only 21 scenarios assume no CCS in the 480–530-ppm pathways (254 scenarios assume CCS), raising the question about the plausibility of reaching a ⩽2°C (50% probability) goal without significant CCS deployment.

3.3.4. Sensitivity to non-electricity emission pathways

In our approach, we use simple averages of the emissions of all IPCC scenario-model combinations within a certain ppm range (e.g. 430–480-ppm). However, within this range the emission pathways

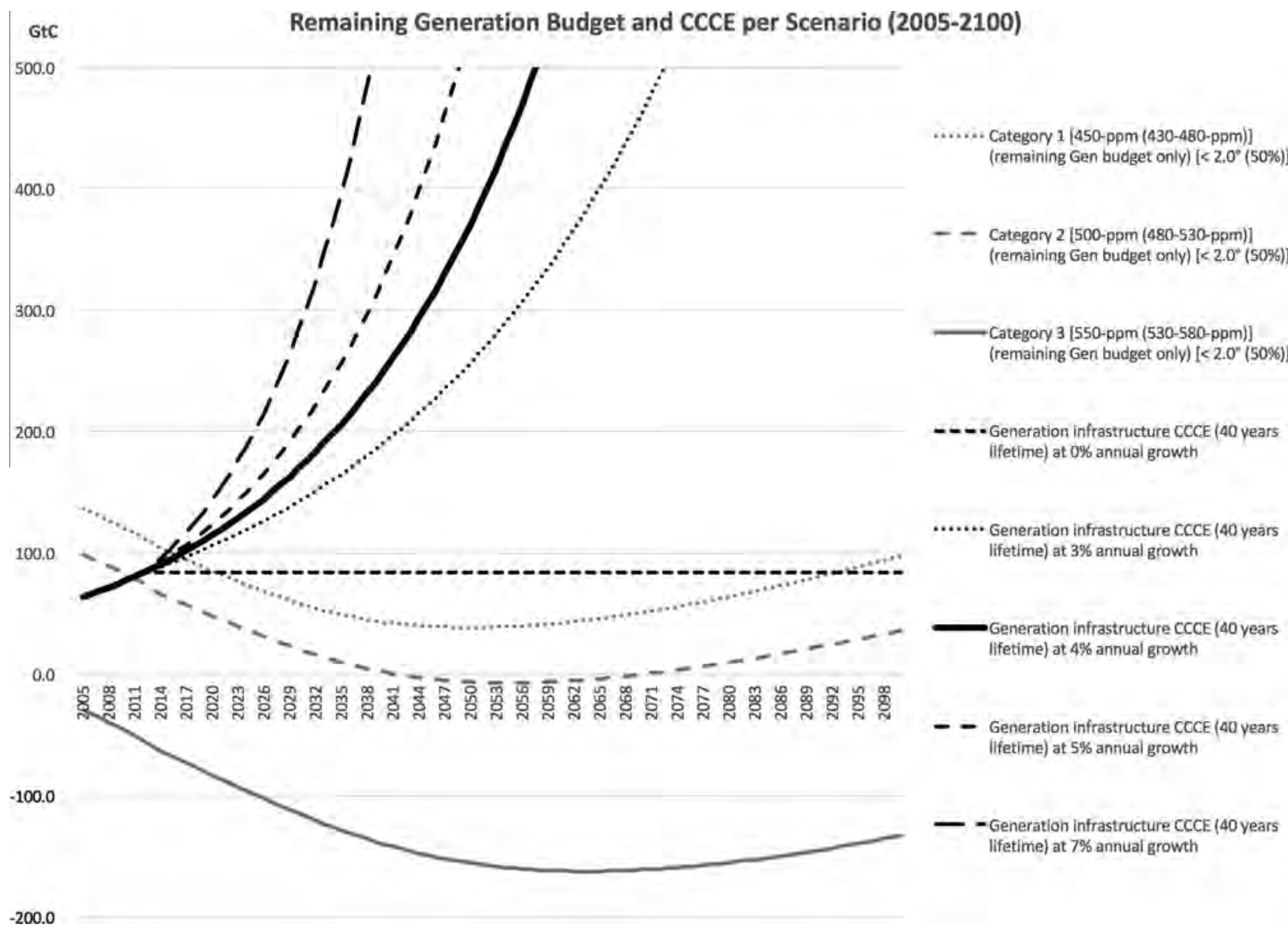

Fig. 3. As for Fig. 2 but for different post-2012 rates of increase in committed cumulative emissions (CCCE) for the electricity sector.

of the combinations can be significantly different from each other. We also test the sensitivity of our results to different emission pathways within the 430–480-ppm and the 480–530-ppm ranges.

For each ppm range, we report the average and median values of each relevant set of scenarios along with the scenario with the maximum and minimum *cumulative 2005–2100 carbon emissions* from the electricity sector. The "max" scenario hence assumes the emissions trajectory of the model-scenario-combination with the highest possible electricity-sector emissions within the respective ppm range[7] (relatively lower non-electricity-sector emissions) and the "min" scenario the trajectory of the combination with the lowest electricity-sector emissions[8] (relatively higher non-electricity-sector emissions).

Table 7 shows that the differences between the "max" and "min" values. Assuming, for example, that non-electricity sector emissions follow a pathway with relatively steep decarbonisation over the next decades ("max" scenario) would leave until 2024 (430–480-ppm scenarios) or 2023 (480–530-ppm scenarios) to completely decarbonise new electricity sector investments (for the 2°C (50% probability) target). Assuming that non-electricity sector emissions follow a pathway with relatively high emissions ("min" scenario) would imply that we already reached the date from which on new electricity sector investments would have been required to be net zero in 2006 or before to stay within the 2°C (50% probability) budget.

3.3.5. Combined sensitivities to emission pathways and CCCE growth rates

We also briefly consider sensitivities to combinations of the assumed CCCE growth rate and the variance in emission pathways. Specifically, we test the sensitivity of the year in which we will have committed to 2°C (50% probability) warming given annual CCCE growth rates of 0–7% in combination with different possible pathways ("min", "max", "median", "average") within the 430–480-ppm and the 480–530-ppm categories.

We find that, assuming extremely low growth rates of CCCE (0–2% p.a.) and emission pathways for non-electricity sectors at the low boundary of possible pathways, the commitment year can be pushed to the late 2020s or even early 2030s. Assuming more likely growth rates of CCCE close to the average growth rates over the past decade of 3–6%, and the same very optimistic non-electricity sector emission pathways the commitment year comes closer to today (2021–2025). Assuming non-electricity sector emissions at the upper boundary of possible 430–480-ppm and 480–530-ppm pathways the annual growth rate of CCCE does not matter as we would have already committed to 2°C in 2006 or before.

4. Discussion

4.1. Policy choices

Nation states affirmed the target to limit warming to below 2°C in 2011 at COP 17 in Durban, and again in 2015 at COP 21 in Paris. The main finding of this paper, however, is that the '2°C capital

[7] MERGE-ETL_2011 + AMPERE2-450-LimSW-HST for the 430–480-ppm range and GCAM 3.0 + EMF27-550-EERE for the 480–530-ppm range.

[8] MERGE_EMF27 + EMF27-450-FullTech for the 430–480-ppm rage and IMACLIM v1.1 + AMPERE2-450-NucOff-LST for the 480–530-ppm range.

Table 4
As for Table 4 but assuming a 3% p.a. growth rate of CCCE from 2012 on (bold years are future years, after 2015).

Lifetime of capital stock 40 years at 3% annual growth					Year of budget commitment (2006–2100)[e]						
	Warming[a]	Likelihood[b] (%)	Budget (CCE)[c] in 2014	Committed CCE[d] in 2014	Cat. 1 450-ppm (430–480-ppm)	Cat. 2 500-ppm (480–530-ppm)	Cat. 3 550-ppm (530–580-ppm)	Cat. 4 580–650-ppm	Cat. 5 650–720-ppm	Cat. 6 720–1000-ppm	Cat. 7 >1000-ppm
[GtC]	<1.5°	66	77	89	<2006	<2006	<2006	<2006	<2006	<2006	<2006
		50	118	89	<2006	<2006	<2006	<2006	<2006	<2006	<2006
		33	200	89	<2006	<2006	<2006	<2006	<2006	<2006	<2006
	<2.0°	66	241	89	<2006	<2006	<2006	<2006	<2006	<2006	<2006
		50	322	89	**2017**	2011	<2006	<2006	<2006	<2006	<2006
		33	377	89	**2026**	**2020**	<2006	<2006	<2006	<2006	<2006
	<3.0°	66	622	89	**2060**	**2055**	**2036**	**2027**	2013	<2006	<2006
		50	731	89	**2070**	**2066**	**2050**	**2041**	**2029**	<2006	<2006
		33	853	89	**2079**	**2075**	**2063**	**2054**	**2043**	**2017**	<2006

[a] Warming due to CO_2 and non-CO_2 drivers. Temperature values are given relative to the 1861–1880 period.
[b] Fractions of scenario simulations meeting the warming objective with that amount of CCE.
[c] CCE at the time the temperature threshold is exceeded that are required for 66%, 50%, and 33% of the simulations assuming non-CO_2 forcing follows the RCP8.5 scenario (similar emissions are implied by the other RCP scenarios). For the most scenario–threshold combinations, emissions and warming continue after the threshold is exceeded. Nevertheless, because of the cumulative nature of the CO_2 emissions these figures provide an indication of the cumulative CO_2 emissions implied by simulations under RCP-like scenarios.
[d] Only electricity generation capital stock based on Davis and Socolov [16]: CCCE of 307GtCO_2 (84GtC) in 2012 growing by 3% p.a. after 2012. (assuming a 40 year lifetime).
[e] Year of budget commitment is the year in which enough electricity generation capital stock is built to consume remaining budget for only electricity generation.

Table 5
As for Table 4 but only scenarios that don't use CCS in the next century are included in the grouping means (bold years are future years, after 2015).

Lifetime of capital stock 40 years at 4% annual growth					Year of budget commitment (2006–2100)[e] Without CCS						
	Warming[a]	Likelihood[b] (%)	Budget (CCE)[c] in 2014	Committed CCE[d] in 2014	Cat. 1 450-ppm (430–480-ppm)	Cat. 2 500-ppm (480–530-ppm)	Cat. 3 550-ppm (530–580-ppm)	Cat. 4 580–650-ppm	Cat. 5 650–720-ppm	Cat. 6 720–1000-ppm	Cat. 7 >1000-ppm
[GtC]	<1.5°	66	77	90	<2006	<2006	<2006	<2006	<2006	<2006	<2006
		50	118	90	<2006	<2006	<2006	<2006	<2006	<2006	<2006
		33	200	90	2012	<2006	<2006	<2006	<2006	<2006	<2006
	<2.0°	66	241	90	**2017**	2008	<2006	<2006	<2006	<2006	<2006
		50	322	90	**2029**	**2019**	<2006	<2006	<2006	<2006	<2006
		33	377	90	**2035**	**2027**	2007	<2006	<2006	<2006	<2006
	<3.0°	66	622	90	**2054**	**2050**	**2038**	**2030**	<2006	<2006	<2006
		50	731	90	**2060**	**2056**	**2047**	**2039**	<2006	<2006	<2006
		33	853	90	**2065**	**2062**	**2054**	**2048**	**2021**	**2019**	<2006

[a] Warming due to CO_2 and non-CO_2 drivers. Temperature values are given relative to the 1861–1880 period.
[b] Fractions of scenario simulations meeting the warming objective with that amount of CCE.
[c] CCE at the time the temperature threshold is exceeded that are required for 66%, 50%, and 33% of the simulations assuming non-CO_2 forcing follows the RCP8.5 scenario (similar emissions are implied by the other RCP scenarios). For the most scenario–threshold combinations, emissions and warming continue after the threshold is exceeded. Nevertheless, because of the cumulative nature of the CO_2 emissions these figures provide an indication of the cumulative CO_2 emissions implied by simulations under RCP-like scenarios.
[d] Only electricity generation capital stock based on Davis and Socolov [16]: CCCE of 307GtCO_2 (84GtC) in 2012 growing by 4% p.a. (assuming a 40 year lifetime).
[e] Year of budget commitment is the year in which enough electricity generation capital stock is built to consume remaining budget for only electricity generation.

Table 6
As for Table 5 but only scenarios that use CCS in the next century are included in the grouping means (bold years are future years, after 2015).

Lifetime of capital stock 40 years at 4% annual growth					Year of budget commitment (2006–2100)[e] With CCS						
	Warming[a]	Likelihood[b] (%)	Budget (CCE)[c] in 2014	Committed CCE[d] in 2014	Cat. 1	Cat. 2	Cat. 3	Cat. 4	Cat. 5	Cat. 6	Cat. 7
					450-ppm (430–480-ppm)	500-ppm (480–530-ppm)	550-ppm (530–580-ppm)	580–650-ppm	650–720-ppm	720–1000-ppm	>1000-ppm
[GtC]	<1.5°	66	77	90	<2006	<2006	<2006	<2006	<2006	<2006	<2006
		50	118	90	<2006	<2006	<2006	<2006	<2006	<2006	<2006
		33	200	90	<2006	<2006	<2006	<2006	<2006	<2006	<2006
	<2.0°	66	241	90	<2006	<2006	<2006	<2006	<2006	<2006	<2006
		50	322	90	**2016**	2010	<2006	<2006	<2006	<2006	<2006
		33	377	90	**2023**	**2018**	<2006	<2006	<2006	<2006	<2006
	<3.0°	66	622	90	**2048**	**2044**	**2031**	**2024**	2013	<2006	<2006
		50	731	90	**2055**	**2052**	**2041**	**2035**	**2026**	<2006	<2006
		33	853	90	**2061**	**2059**	**2050**	**2045**	**2037**	**2015**	<2006

[a] Warming due to CO_2 and non-CO_2 drivers. Temperature values are given relative to the 1861–1880 period.
[b] Fractions of scenario simulations meeting the warming objective with that amount of CCE.
[c] CCE at the time the temperature threshold is exceeded that are required for 66%, 50%, and 33% of the simulations assuming non-CO_2 forcing follows the RCP8.5 scenario (similar emissions are implied by the other RCP scenarios). For the most scenario–threshold combinations, emissions and warming continue after the threshold is exceeded. Nevertheless, because of the cumulative nature of the CO_2 emissions these figures provide an indication of the cumulative CO_2 emissions implied by simulations under RCP-like scenarios.
[d] Only electricity generation capital stock based on Davis and Socolov [16]: CCCE of 307GtCO$_2$ (84GtC) in 2012 growing by 4% p.a. (assuming a 40 year lifetime).
[e] Year of budget commitment is the year in which enough electricity generation capital stock is built to consume remaining budget for only electricity generation.

stock' for the global electricity generation sector will be reached in 2017. Even this finding assumes emissions from other sectors shift onto a 2°C consistent pathway, which may well be optimistic. In short, the energy system is now at risk of undermining climate stability, perhaps the most important aspect of our natural capital and a key asset of a 'green economy'.

Our findings raise several fundamental questions, discussed in Section 4.3 below, but they also raise immediate and significant implications for the electricity sector. Logically, achieving the necessary transformation of the global electricity generation sector is going to require some combination of the following four options:

(1) New electricity generation assets are 100% zero carbon as soon as possible.
(2) Existing fossil assets are retrofitted with carbon capture.
(3) Existing fossil assets are stranded early, replaced by zero carbon assets.
(4) CDR technologies are used to hold temperatures below 2°C.

The most cost-effective combination of these four options will depend strongly upon the rates of decline in the costs of the relevant technologies, including nuclear, renewables including hydro, carbon capture, associated grid balancing technologies (including storage) and negative emission technologies. We briefly consider the four options in turn before examining the policy interventions that could support them.

First, numerous studies document the rapid cost declines of renewable energy [42–44], the feasibility of large scale deployment of zero emissions technologies including renewables, biomass, hydro, and nuclear [43,45,46], the overall modest macroeconomic costs such a program would entail [43,47,48], and the significant co-benefits of widespread zero carbon deployment [49,50]. Challenges remain, both on cost and grid integration [51,52], but large-scale deployment of zero carbon electricity appears inevitable; the question is not if but how fast.

Second, significant carbon capture deployment seems essential to enable existing or soon to be created carbon-emitting infrastructure to be retrofitted in order to reduce committed cumulative emissions (especially if mitigation in other sectors turns out harder than expected). Whilst CCS technologies are amongst the most expensive mitigation options available today, nearly all 2°C consistent pathways depend on significant CCS deployment in order to provide net negative emission capabilities, and excluding CCS technologies increases the modelled cost of meeting 2°C by around 2.5 times [12,38].

Third, new fossil assets deployed after reaching the 2°C capital stock could be retired early and replaced by zero carbon assets. While this is unlikely to economically superior to investing in zero carbon assets in the first place, there may be some value in delay; the costs of zero carbon technologies are declining rapidly and on average remain more expensive than fossil fuels. However, recent research shows that the cost declines are significantly attributable to increases in cumulative production volumes of zero carbon technologies [53], thus delay may significantly slow such price declines. Thus earlier action to shift to investments in zero emissions new capital stock may not only avoid later stranding of assets, but also accelerate the decline in costs of zero emissions technologies.

Finally, given the current trajectory of the global energy system and timeframes required to shift all new global energy investment to zero carbon, the probability of overshooting the 2°C capital stock is significant. Increased investments in CDR technologies might help mitigate such overshoot and to minimize asset stranding. However, given the current costs and technical challenges with widespread CCS deployment [54] it would not be prudent to rely

Table 7
Year in which generation budget is committed (assuming 40 years lifetime and 4% growth p.a.) for mean, median, min, and max electricity emission pathways in 2 different scenario groupings and peak warming budgets (bold years are future years, after 2015).

Lifetime of capital stock 40 years at 4% annual growth					Year of budget commitment (2006–2100)[e]							
	Warming[a]	Likelihood[b] (%)	Budget (CCE)[c] in 2014	Committed CCE[d] in 2014	450-ppm (430–480-ppm)				500-ppm (480–530-ppm)			
					Average	Median	Min	Max	Average	Median	Min	Max
[GtC]	<1.5°	66	77	90	<2006	<2006	<2006	<2006	<2006	<2006	<2006	<2006
		50	118	90	<2006	<2006	<2006	<2006	<2006	<2006	<2006	<2006
		33	200	90	<2006	<2006	<2006	2008	<2006	<2006	<2006	2007
	<2.0°	66	241	90	<2006	<2006	<2006	2014	<2006	<2006	<2006	2013
		50	322	90	**2017**	**2016**	2006	**2024**	2011	2013	<2006	**2023**
		33	377	90	**2024**	**2024**	2014	**2029**	**2019**	**2021**	<2006	**2029**
	<3.0°	66	622	90	**2048**	**2049**	**2043**	**2048**	**2045**	**2046**	**2031**	**2048**
		50	731	90	**2055**	**2056**	**2052**	**2055**	**2053**	**2054**	**2041**	**2054**
		33	853	90	**2062**	**2062**	**2059**	**2061**	**2059**	**2060**	**2051**	**2060**

[a] Warming due to CO_2 and non-CO_2 drivers. Temperature values are given relative to the 1861–1880 period.
[b] Fractions of scenario simulations meeting the warming objective with that amount of CCE.
[c] CCE at the time the temperature threshold is exceeded that are required for 66%, 50%, and 33% of the simulations assuming non-CO_2 forcing follows the RCP8.5 scenario (similar emissions are implied by the other RCP scenarios). For the most scenario–threshold combinations, emissions and warming continue after the threshold is exceeded. Nevertheless, because of the cumulative nature of the CO_2 emissions these figures provide an indication of the cumulative CO_2 emissions implied by simulations under RCP-like scenarios.
[d] Only electricity generation capital stock based on Davis and Socolov [16]: CCCE of 307GtCO$_2$ (84GtC) in 2012 growing by 4% p.a. (assuming a 40 year lifetime).
[e] Year of budget commitment is the year in which enough electricity generation capital stock is built to consume remaining budget for only electricity generation.

Table 8
Year in which generation budget for ⩽2°C (50% probability) is committed (assuming 40 years lifetime and different annual growth rates of CCCE) for mean, median, min, and max realised emissions in 2 different scenario groupings and peak warming budgets (bold years are future years, after 2015).

Annual growth rate of CCCE[a] (%)	Year of budget commitment (2006–2100) for <2°C (50% probability)								
	Cat. 1 450-ppm (430–480-ppm)				Cat. 2 500-ppm (480–530-ppm)				Cat. 3–7 (>530-ppm)
	Average	Median	Min	Max	Average	Median	Min	Max	Average
0	**2021**	**2021**	2006	**2033**	2011	2014	<2006	**2034**	<2006
1	**2019**	**2019**	2006	**2030**	2011	2013	<2006	**2030**	<2006
2	**2018**	**2018**	2006	**2027**	2011	2013	<2006	**2027**	<2006
3	**2017**	**2017**	2006	**2025**	2011	2013	<2006	**2025**	<2006
4	**2017**	**2016**	2006	**2024**	2011	2013	<2006	**2023**	<2006
5	**2016**	**2016**	2006	**2022**	2011	2013	<2006	**2022**	<2006
6	**2016**	**2016**	2006	**2021**	2011	2013	<2006	**2021**	<2006
7	**2015**	**2015**	2006	**2020**	2011	2013	<2006	**2020**	<2006

[a] Assumed annual growth rate of CCCE from 2012; assumed 40 year lifetime of capital stock.

on CDR in later years as an alternative to rapid de-carbonization of the electricity generation system.

4.2. Policy instruments

In the introduction to this paper, we noted that annual CO_2 emission reduction targets only indirectly address the ultimate goal; it is possible to meet short-term flow targets while simultaneously installing new coal-fired power stations that make it economically impossible to meet cumulative emission targets. Better is to directly target cumulative emissions, and better still are policies that are a function of an index of attributable warming. In contrast, targets that are a function of time do not map directly onto cumulative emissions or to the observed climate response.

This distinction becomes relevant in the debate about the virtue of coal to gas substitution, which would reduce near-term emission flows. A stock-based analysis makes clear that coal to gas switching is only worthwhile if it reduces the expected future CCE. This may well be achieved if the fuel switching from coal to gas involves no new construction; existing gas-fired plants are run at a higher load factors, coal-fired plants are run at lower load factors. However, if new capital expenditure on gas is required, the analysis is more complicated. For instance, a 1GW coal-fired power station with emissions intensity of 1tCO$_2$/MWh and a load factor of 70% will emit 6.1MtCO$_2$ per annum.[9] With a residual lifetime of 10 years, expected future cumulative CO_2 emissions are therefore 61MtCO$_2$. Suppose this plant were retired early and replaced by a 1GW combined cycle gas turbine (CCGT) plant with emissions intensity of 0.5tCO$_2$/MWh a load factor of 70%, hence emitting 3.05MtCO$_2$ per annum. With a lifetime of 40 years, expected future cumulative emissions from the CCGT would be 122MtCO$_2$, compared to 61MtCO$_2$ from the coal plant. While annual emissions are cut in half over the first ten years, it is impossible to determine whether such switching reduces emissions unless it is specified what occurs after the coal-fired power station is closed in 10 years. If it would have otherwise been replaced with clean renewable energy, perhaps driven by continuing cost declines, then the strategy of switching from coal to gas will have been counterproductive. More careful analysis is required [55,56].

We now examine policy instruments that are candidates for constraining cumulative emissions to meet a 2°C target. Each

[9] 1GW × 365 days/year × 24h/day × 70% load factor = 6132GWh × 1000 MWh/GWh = 6,132,000 or 6.132 mio. MWh × 1 tCO$_2$/MWh = 6.132 mio. tons of CO_2 per annum.

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instrument incentivises one or more of the four options in Section 4.1.

4.2.1. Carbon prices

Carbon prices support action on all four options. They create incentives for actors to invest in new zero carbon assets, to retrofit (where economically and technically feasible) existing assets with carbon capture, to retire the highest emitting stock earlier and to develop negative emissions technologies. Carbon prices have the benefits of being technologically neutral and create incentives to de-carbonize efficiently. They work simultaneously on the demand and the supply side, increasing the costs to consumers of polluting fossil fuels, and reduce the returns to producers. They may also provide an economic 'double dividend' [57–60] of accelerating the transition to a green economy while simultaneously permitting reform and greater efficiency of the existing tax system, which tends to tax goods rather than bads.

However, the analysis in this paper makes clear that the scale and pace of the energy sector transformation required is dramatic. The level of carbon prices required to deliver, without other interventions, this rapid transformation would be far higher than is politically feasible in most countries, especially when it is considered that current effective net carbon prices may be negative, accounting for fossil fuel subsidies [52]. But this does not mean that carbon prices should be rejected; they should be implemented to the extent politically feasible (whether by a carbon tax or a quantity constraint and trading scheme). Pragmatism requires additional policy instruments.

4.2.2. Cumulative cap and trade

One more novel form of carbon pricing would be a *cumulative* emissions cap and trade system (cf [61]) consistent with estimates of the remaining carbon budget and the energy sector's appropriate share of that budget. This is different to existing cap and trade systems, which largely operate on a period-by-period basis, even if future emissions trajectories are sometimes described decades into the future. A cap on cumulative emissions would provide visibility of the carbon budget across the full lifetime of the assets. If it were credible, it would create incentives for de-carbonization of new capital stock and optimization of the existing portfolio (retrofits and retirements). Unfortunately, however, credibility over many decades is very difficult to achieve in practice, given the nature of changing governments in democratic societies.

4.2.3. Licensing requirements

Rules could be established to (1) require all new power plants to have zero (or close to zero) emissions; and (2) prevent high-emitting plants from being granted life extensions. Licensing rules have the political benefits of simplicity and clarity, and could potentially reduce the political economy challenges of allocating permits either within or between countries [62]. This approach might also reduce the political economy challenges of asset stranding. A more gradual version is to regulate carbon intensity in $kgCO_2/kWh$. China has taken this approach in its 5-year plan, as have several U.S. states [63]. Such rules could have the perverse effect of incentivizing a rush to build high emitting assets before the intensity target ratchets down to zero, but our analysis suggests the target should reach zero faster than the time it takes to plan and consent a new power plant.

4.2.4. Technology-based deployment support

Another approach is to regulate, subsidize, or tax specific energy producing technologies. Examples include:

- Subsidies or other regulations for accelerated renewable deployment (e.g. a feed-in-tariff or renewable portfolio standard).
- Subsidies for nuclear plans.
- Requiring all new coal plants to have CCS.

However, technology-based regulation has significant disadvantages. They tend to be inefficient, and more prone to regulatory capture than broad-based economic instruments. A well-designed ramp down to zero emissions for new electricity generation would be more effective, for it would not support one specific technology over another. For instance, renewable portfolio standards ignore potential contributions from non-renewable zero carbon sources (nuclear, fossil with CCS).

4.2.5. Research and development support

Finally, given that one of the most important variables is the relative cost of clean and dirty technologies, and given that there are well-understood market failures in research and innovation, there is a clear and well-accepted role for government to support clean technology research and development [63]. The surprise is that so little funding, relative for instance to implicit fossil fuel subsidies, is directed towards the brainpower that might actually provide solutions to vital human problems. The recent announcement at the first day of the COP21 of a coalition of countries and private sector investors to invest several billion dollars in clean energy R&D is well grounded in economic and political logic. The initiative is being led by Bill Gates and includes at least 20 countries (e.g. the U.S., France, India and others), which are expected to double the amount of R&D investment for clean energy from $5 to $10 billion over the next five years.

In addition, a policy offering a balance of effectiveness, efficiency, and political tractability may be an agreement that all *new* electricity generation (and any lifetime extensions) be zero carbon by a date in the near future, with countries agreeing their own ramps to that goal (cf [62]). Careful thought would need to go into designing such an agreement to minimize gaming during the transition period, but a zero carbon new build target by a fixed date has the advantages of simplicity and ease of monitoring.

4.3. Broader questions and directions for future research

Our finding that the 2°C capital stock for the global electricity generation will have been built by 2017 is based on the assumption that the transport, industry, land-use, etc. sectors also transition to a 2°C compatible pathway. Further detailed analysis of the committed emissions of these other sectors of the economy is needed. Taking into account the lifetime of transport assets (i.e. ships, trucks, cars, airplanes), industry assets (factories, mines, etc.), and residential assets (buildings, etc.) a closer analysis of the historic and expected development in these sectors would likely suggest that we have already passed the point of a 50% probability of 2°C without negative emissions or asset stranding.

Given the implausibility of all new electricity generation assets being zero carbon from now onwards, the role of both CCS and CDR are brought into focus [12]. How realistic is it to expect the successful large-scale deployment of CCS and CDR technologies? At present, rates of investment and deployment of these technologies are entirely negligible compared to the scale at which they appear to be required. Without major changes in policy or remarkable reductions in cost, both potentially important areas for further research, it does not appear realistic to expect these technologies to be deployed at scale.

If so, the only remaining logical outcomes are either that there is significant early stranding of fossil assets over the coming few decades – perhaps because accelerated cost declines in clean energy make this economically rational – or humanity accepts risks above 50% of exceeding 2°C warming. The implications for risks to investors in fossil fuels are rapidly becoming obvious. Further research is urgently needed on both the technologies, policies and institutions that could bring the costs of clean energy down as quickly as possible. So too is research on managing the process of asset stranding.

Finally, the analysis in this paper also raises a range of broader questions about the sustainability of our energy and economic systems. Existing policies are clearly inadequate to tackle global environmental problems, such as climate change or biodiversity loss. Much greater effort is required to create prices – including carbon prices – and economic incentives to ensure that individuals and corporations protect the natural environment. Carbon and other environmental prices form part of a broader shift in green fiscal policy away from taxing goods (labour) to taxing bads (pollution). Such a tax shift can generate a 'double dividend'. It is certainly time, as the IMF has argued, to cut subsidies for fossil fuel use [64].

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