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Tilting at Windmills: Making a case for reframing electric sector climate policies

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Abstract

Tilting at Windmills: Making a case for reframing electric sector climate policies is a study that evaluates current climate policies through the application of performance metrics reflecting a proportional electric sector emission allocation in a 22 Gt by 2040 two-degree scenario. The study evaluates international electric sector climate policy shortcomings and draws electricity sector climate policy lessons from a case study of California. The study develops the components of an Electricity CO_2 Emission Footprint Pathway Model (E-Path) and applies this analytical framework to US power systems to quantify how increasing anthropogenic CO_2 emission charges can map the least-cost pathway for reducing the 2040 US electricity sector CO_2 emission footprint. The assessment indicates that an efficient US electricity climate policy initiative would increase 2040 real retail electricity prices by around 43 percent, including the 11 percent price increase from internalizing a 125 \$(2014) per metric ton CO_2 emission charge that recirculates around 46 billion (\$2016) revenues per year to consumers. The study concludes with climate policy recommendation that the US lead by example to achieve a global warming solution by phasing-out subsidies and mandates, and phasing-in a CO_2 emission charge that starts out around 40 \$(2014) per metric ton and increases to around 125 \$(2014) per metric ton by 2040.

Preface

Climate policy initiatives are generally viewed in a considerably more positive light than is objectively justified. Because here is the rub: despite over 25 years of climate policy initiatives, the global warming problem is getting worse. The electricity sector currently accounts for one-third of annual anthropogenic CO_2 emissions and was one of the fastest growing sources of GHG emissions over the past 25 years. The bottom line is that an overall solution to the global warming problem requires worldwide actions to significantly reduce greenhouse gas emissions within the next 25 years—including significant and sustained electricity sector CO_2 emission reductions.

Current leading-edge electricity climate policy initiatives are proving inefficient and ineffective. Electricity sector climate policies are failing because policy formulation typically reflect appealing, but unrealistic approaches that fail to confront realistic cost assessments. Instead, these approaches reflect policy formulations based on pathways described in multiple influential studies suggesting that the global electricity sector can do its part to generate the benefits of limiting global warming at little or no cost. From this low-cost perspective, technological innovation is reinforcing the growing political will to address climate change and driving an inevitable transition toward a low carbon future. This low-cost transition involves implementing changes to both demand and supply-side factors. Demand side alterations involve efficiency gains large enough to delink increases in electric consumption from economic growth while generating savings rather than costs. On the supply side, alterations involve shifting electric generation primarily to renewable resources, such as wind and solar technologies that are available at grid parity costs to conventional generating technologies and enabled by battery storage technology breakthroughs paired with smart grid capabilities to reshape electric demand patterns to align with intermittent renewable generation output patterns.

A low-cost pathway to solving the global warming problem is an appealing idea that people want to believe is true. However, the low-cost pathway narrative is at odds with the preferences of electricity consumers, the state of energy end use technologies, the inherent rigidity in fuel input requirements for electricity generation, the electric infrastructure technology turnover rate, the complexity of modern electricity system operations, and the economic trade-offs required to alter the demand and supply-sides of the electricity sector.

Tilting at windmills makes a case for reframing electric sector climate policies based on a realistic assessment of the complexity and cost associated meeting the climate policy challenge in a developed economy electricity sector. However, neither the US nor any other nation can solve the global warming problem on its own. As a result, an effective solution likely requires a developed world economy to lead by example, particularly in the electricity sector, by demonstrating how electricity demand and supply-side alterations can support modern electric intensive lifestyles, while reaching climate policy objectives at a politically acceptable cost.

The divergence of opinion regarding climate policy cost impacts explains some of the current conflict in climate policy formulation. From the low-cost perspective, there is no cost constraint to moving climate policy forward and no concern that doing so could create a competitive disadvantage if other nations do not follow suit. From a perspective that recognizes significant costs, a political challenge exists to move forward with politically acceptable costs, and a significant risk exists that unilateral actions will generate a competitive disadvantage versus other countries that do not follow suit. In addition, costly unilateral action runs the risk of producing a policy failure if the impact of unilateral actions is offset by failures to act elsewhere.

This study outlines how the US could lead the way to solving the electricity climate policy challenge by reframing climate policies to phase-out subsidies and mandates and phase-in a CO_2 emission charge starting out around 40 $(2014) per metric ton and reaching and 125 $(2014) per metric ton by 2040. Such reframing of US electricity climate policy can coordinate the complex mix of demand and supply-side changes that map the least-cost pathway to achieving significant and sustainable reductions in future electricity CO_2 emission footprints.

Acknowledgements

After working four decades as an energy economist, a Senior Fellowship at the Mossavar-Rahmani Center for Business and Government at Harvard University provided me with the opportunity to engage with an exceptional research community to explore why and how reframing electric sector climate policy initiatives could help lead to an effective and efficient approach to addressing the climate change policy challenge. However, this research proposal did not involve a mainstream perspective on climate policy, and special thanks goes to William Hogan, the Raymond Plank Professor of Global Energy Policy at the Kennedy School for his support as my Senior Fellowship sponsor. In addition, Richard Zeckhauser, and John Haigh provided ongoing support for the Senior Fellowship program and offered valuable insights along the way. Scott Leland, Paul Sherman, and Susan Gill facilitated interactions with faculty, senior fellows and students and assisted me in numerous ways. Jason Peuquet and Mounia Mostefaoui provided valuable contributions, along with my IHS Markit research colleague Aaron Marks. Ashley Brown, Louisa Lund and Jo-Anne Mahoney provided helpful engagement with the Harvard Electricity Policy Group. Last, but not least, my wife Aileen supported my application of time and effort to conduct this research. Although I could not have accomplished this research effort without all this help, nevertheless, the research, analysis and interpretations are my views and any oversights are my responsibility.

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Contents

Summary

The global warming problem is getting worse because atmospheric concentrations of CO_2 continue to increase. The global electricity sector is a large and growing source of anthropogenic CO_2 emissions. Reducing global electricity CO_2 emissions is a necessary part of any effective solution. The most economically efficient pathway to achieving climate policy goals involves imposing an appropriate charge on CO_2 emissions while eliminating the distortions of command and control climate policies.

This study develops an electricity CO_2 emission footprint analytical framework to assess the size and timing of electricity sector climate policy initiatives. Current US electricity sector CO_2 emissions are around 13,000 lbs. of CO_2 emissions per capita and over three times the global average. The study develops a "22 Gt by 2040" scenario for limiting the impact of global warming to a two-degree Celsius increase from the global pre-industrial average temperature. The scenario involves reaching the global climate policy goals of 5,500 lbs. CO_2 emissions per capita by 2040 with an electric sector allocation of 2,400 lbs. CO_2 emissions per person per year.

Policy evaluations employing the electricity CO_2 emission footprint metric indicate that leading-edge electric sector climate initiatives, such as California, are proving inefficient and ineffective at closing the gap between electricity CO_2 emission footprints and climate policy goals. A case study indicates the shortcomings reflect climate policy initiatives at odds with the preferences of electricity consumers, the state of technology, the underlying physics, and the economic trade-offs that shape electric power system outcomes.

This study confronts the cost of electric sector CO_2 emission reduction associated with a realistic assessment of the available state of electricity sector technology. An analysis of the least-cost pathway to reducing the US electricity CO_2 emission footprint by 2040 employs the Electricity CO_2 Emission Footprint Pathway Model (E-Path) to analyze the move from the 2040 baseline electricity CO_2 emission footprint to the 2,400 annual lbs. CO_2 emission per capita policy goal. Following the least-cost pathway to reducing the 2040 electricity CO_2 emission footprint involves coordinating a complex mix of demand and supply-side alterations in the US electricity sector. On the demand side, the least-cost pathway involves electric consumption efficiency gains driven primarily by retail electricity price increases along with some expanded ratepayer-funded efficiency programs. On the supply side, the least-cost pathway involves operating significant non-CO_2 emitting hydro and nuclear baseload resources, along with fossil-fueled generation resources dominated by net-load following natural gas-fired technologies that back up and fill in for the minority generation share comprised of intermittent wind and solar resources.

Analysis of least-cost pathway indicates that without game-changing technological breakthroughs, meeting the electricity climate policy challenge is going to be expensive, even allowing for the deployment of potential advanced technologies. The E-Path based cost estimate to meet the US electricity sector climate policy challenge in the potential advanced state of technology case involves an increase in the 2040 average real electricity price increase of about 45 percent from current price levels rather than an increase of only 2 percent in the baseline case where no additional resources are deployed to address climate change.

The retail price impact is a likely political roadblock to formulating and implementing climate policy, even though recycling the CO_2 emission charge—that accounts for 11 of the 45 percent retail price increase—can temper some of the regressive cost impacts and political resistance. In addition, phasing-in climate policy change likely improves the chances of overcoming political roadblocks. Therefore, the climate policy recommendation is to shift away from business-as-usual climate policies and toward the least-cost

pathway by phasing-out the distortions from environmental mandates and subsidies while phasing-in (with periodic review and adjustment) a charge on CO_2 emissions beginning around 40 \$(2014) per metric ton (the mid-range estimates for the social cost of carbon) and reaching around 125 \$(2014) per metric ton (E-PATH potential advanced technology case to reach 2,400 annual lbs. CO_2 emission per capita outcome) by 2040.

Tilting at Windmills: Making a case for reframing electricity sector climate policies

Introduction

A significant and sustained reduction in the carbon dioxide (CO_2) emissions from the world's electricity sector is a necessary part of any solution to the worsening global warming problem. Currently, fossil-fueled electric generation technologies remain a cost-effective way to produce electricity and as a result, the global power sector accounts for close to one-third of global greenhouse gas (GHG) emissions. The one-third increase in global Gross Domestic Product (GDP) per capita over the past quarter century drove a doubling of worldwide electric energy consumption and made the electricity sector one of the fastest growing sources of anthropogenic GHG emissions. Global economic development trends will likely double worldwide electric energy consumption again within the next twenty-five years. Consequently, the political pressure to do more to address climate change in general, and particularly in the electricity sector, will likely increase as the global warming problem worsens in the years ahead.

Solutions to the global warming problem are not materializing. Electric sector climate policy implementations that are most often regarded as leading-edge initiatives are proving inefficient and ineffective. Electric sector climate policy initiatives are failing because approaches are at odds with the preferences of consumers, the state of technology, the underlying physics, and the economic trade-offs that shape electric power system outcomes.

Formulating effective electricity sector climate initiatives requires recognizing that reducing electricity sector GHG emissions across several decades is going to be complex, costly and politically challenging with the expected available state of technology. Research and development will likely produce innovations that advance the state of technology, but without a technological breakthrough, deploying advanced technologies will still involve CO_2 emission reduction costs that are politically challenging. Therefore, a climate formulation challenge exists to confront realistic cost estimates and increase the probability of generating the political will to implement effective solutions by focusing on approaches that minimize the cost of achieving CO_2 emission reductions.

No single electric system can solve the global warming problem on its own. Limiting electricity sector GHG emissions to the levels aligned with climate scientist's assessments of the sensitivity of global temperatures to GHGs in the atmosphere requires complementary worldwide electric sector climate initiatives. As a result, an effective solution likely requires leadership by example. This requires a developed country to demonstrate an appealing example and trigger the complementary and efficient worldwide electric sector climate initiatives required to deliver the electricity sector's contribution to solving the global warming problem. Although the US is withdrawing from the Paris Climate Agreement, the political pressure in the US to address climate change is not going away. Therefore, the US is positioned to lead by example and show the world how an electricity sector can achieve an electricity CO_2 emission profile that aligns with climate policy goals while also supporting the electric intensive lifestyle found in a modern developed economy.

Formulating effective and efficient approaches to addressing the global warming problem in the electricity sector involves four steps:

1. **Define the scale and scope of the problem and the available solution frameworks**—in the global as well as the electricity sector context.

2. **Identify appropriate and measurable goals**—to pace how far and how fast the electricity CO_2 emissions need to be reduced in the decades ahead, and to evaluate climate policy performance.
3. **Learn lessons from past climate policy shortcomings**—leading-edge electricity sector climate initiatives do not provide an example for other power systems to follow. Nevertheless, an examination of the leading-edge climate policy initiatives, such as California, provides lessons to shape effective and efficient climate policy initiatives going forward.
4. **Map out the pathway to an effective and efficient solution**—by analyzing the efficient mix of demand and supply-side alterations in the electricity sector produced by internalizing a CO_2 emission charge.

Chapter 1: The big picture

Scale and Scope of the global warming problem

CO_2 in the atmosphere is part of a complex biogeochemical carbon cycle that sustains life on earth. The pre-industrial carbon cycle involved fluctuations in annual sources and sinks of CO_2 that produced atmospheric concentrations normally ranging from 180 to 280 parts per million (ppm).[1]

Greenhouse gases include CO_2, water vapor, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and hexafluoride. The warming potential of GHGs in the atmosphere varies and GHG measurements are expressed on a carbon dioxide equivalent basis (CO_2e). CO_2 emissions currently account for about 80 percent of annual GHG emissions measured on a CO_2e basis.[2]

Climate scientists provide the mainstream assessment that, with a 95 percent certainty level, human activity is the dominant cause of the increase in the atmospheric concentration of carbon dioxide since 1750 (the industrial era), and that this is the primary cause of observed global warming.[3]

Atmospheric concentrations of CO_2 increased steadily over the industrial era primarily because human activity caused an imbalance in the carbon cycle whereby anthropogenic CO_2 emissions sources persistently exceeded sinks. In the past twenty-five years, the imbalance worsened as annual anthropogenic CO_2e emission sources increased from 30.4 to 44.8 billion metric tonnes ("gigatonnes" or "Gt").

Atmospheric concentrations of CO_2 are now around 400-ppm. Climate scientists estimate that current atmospheric concentrations of CO_2 cause an increase in the average global temperature of 0.6 to 0.9 degree Celsius above pre-industrial levels.[4] The global warming problem is getting worse because, as Figure 1 shows, atmospheric concentrations of CO_2 continue to increase.[5]

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[1] NOAA Earth System Research Laboratory, Carbon Dioxide Information Analysis Center

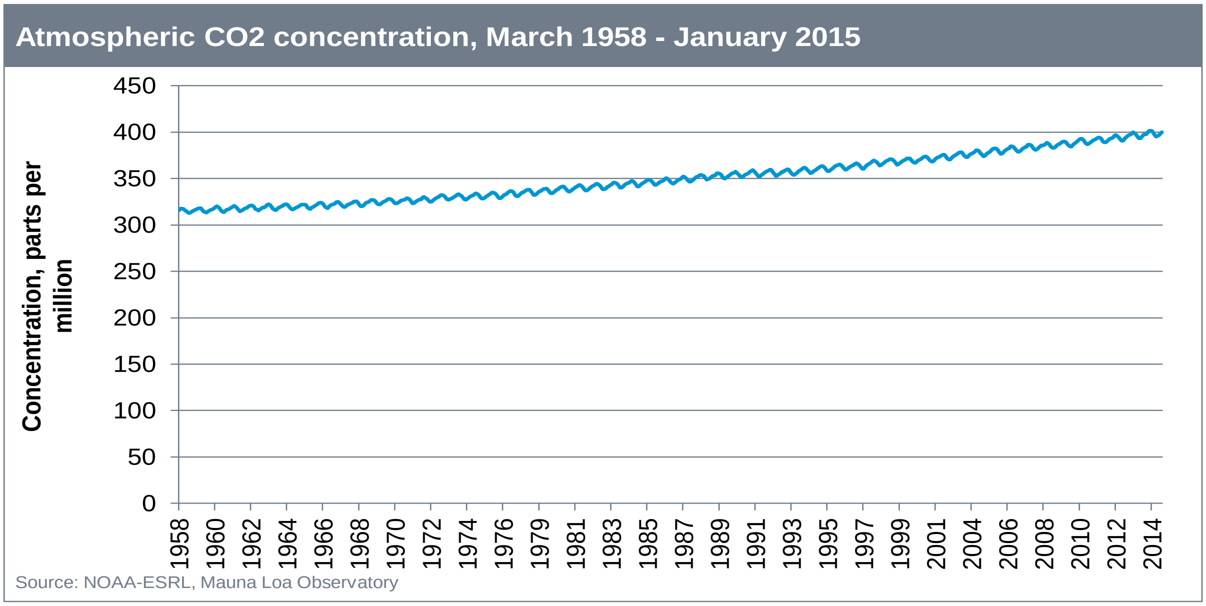
[2] World Resources Institute. *Total GHG emissions excluding land-use change and forestry – 2012*. CAIT – Historical Emissions Data (Countries, U.S. States, UNFCCC). CAIT data browserhttp://www.wri.org/resources/data-sets/cait-historical-emissions-data-countries-us-states-unfccc

[3] IPCC, 2013: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 1535 pp, p v.

[4] Goddard Institute for Space Studies, Surface Temperature Analysis, http://earthobservatory.nase.gov/Features/GlobalWarming/page2.php

[5] Global Earth System Research Laboratory, *Trends in Atmospheric Carbon Dioxide* –Global Monitoring Division. Updated and accessed August 5, 2015. http://www.esrl.noaa.gov/gmd/ccgg/trends/global.html

FIGURE 1



The growing recognition of the potential consequences from increasing average global temperatures generate political pressure to do more to solve the global warming problem. However, the political pressure to address global warming only arose about 25 years ago because, until the mid-1970s, the dominant paradigm of the world's leading climate scientists involved climate change arising from the potential for global cooling rather than global warming.[6] The global cooling hypothesis emerged from climate research focusing on the natural variation present in the earth's climate—especially across timespans measured in hundreds, thousands and even millions of years. The causes of these variations included changes in solar activity, alterations in the shape of the earth's orbit and the wobbling of the earth's rotation about its axis. These types of factors led climate scientists to believe that the earth was in an interglacial period—having emerged from the previous ice age and on the move toward entering another glacial period. These concerns over the threat of eventual global cooling led to climate change stories appearing in the popular press, including the June 1974 issue of Time Magazine and April 1975 issue of Newsweek.[7]

A general awareness of the global warming problem only emerged around thirty years ago when the scientific community concerned with climate change shifted its focus away from global cooling and towards global warming. This paradigm shift owes much to the global cooling skeptics who collected data and tested hypotheses to challenge the dominant paradigm. Within the span of about decade, the development of scientific knowledge concerning the complex and dynamic global climate shifted the mainstream

[6] Science, *When Will the Present Interglacial Period End?* Vol. 178, no. 4057 (1972) pp 190-191.
[7] Time Magazine, *Another Ice Age*, June 24, 1974 and Newsweek, *The Cooling World*, April 28, 1975.

perspective from a future of global cooling to a future of global warming. A milestone in this paradigm shift was the 1988 testimony of NASA scientist James Hansen before the US Congress explaining that global warming was already underway.

The scope of the global warming problem made it clear that addressing climate change required a coordinated worldwide response. No country can solve the global warming problem on its own or for itself because atmospheric GHG emissions are well-mixed in the atmosphere and the emission of CO_2 anywhere in the world has the same impact on the climate everywhere in the world.

Solution Frameworks

The nature of the global warming problem requires a coordinated global solution. Several frameworks exist for formulating climate policy goals, approaches and metrics.

The first framework involves generating an economically efficient outcome by employing a cost versus benefits assessment to equilibrate the marginal cost of CO_2 emission reduction to the marginal benefits. This approach to solving the global warming problem involves imposing an anthropogenic CO_2 emission charge everywhere around the world. The metric employed to set this charge is an estimate of the Social Cost of Carbon (SCC); the economic value of alterations in human health, ecosystems, agriculture, and other facets of life resulting from a marginal change in CO_2 emissions.

Several models exist to provide estimates of the SCC. These models quantify relationships and linkages between socioeconomic factors, CO_2 emissions, climate sensitivity to atmospheric concentrations of CO_2 and net economic damages. William Nordhaus developed and employs the Dynamic Integrated model of Climate and the Economy (DICE) to estimate the balance point between the marginal cost and the marginal benefit of CO_2 emission abatement. His latest assessment involves a policy goal of setting a global CO_2 emission charge of around $40 per ton ($2015) with an escalation rate of 3 percent per year to 2050.[8] The DICE assessment indicates this approach likely results in a 4-degree Celsius increase in average global temperatures from pre-industrial levels around the year 2140.

A comparison of the DICE model results with assessments employing the Climate Framework for Uncertainty, Negotiation and Distribution model (FUND) and the Policy Analysis of the Greenhouse Effect model (PAGE) find significant differences exist in SCC estimates based on model specifications.[9] As a result, current estimates of the social cost of carbon range from 6 to 75 $(2014) per ton.[10] Yet despite uncertainty regarding the optimal CO_2 emission charge, the SCC based policy approach provides a certain conceptual benchmark indicating that an economically efficient solution would involve different CO_2 emission footprints across regions and countries because of the varying locational marginal costs of CO_2 emission abatement options.

A second framework involves equilibrating anthropogenic CO_2 emission sources to sinks to stabilize atmospheric CO_2 concentrations below levels that create dangerous interference with the climate. Analyses employing complex General Circulation Models (GCM) assess the linkage between GHGs and climate change and probable excursions from climate variation tolerances. Since the carbon cycle is complex and dynamic, and many relationships determining the sensitivity of the earth's climate to atmospheric

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[8] William Nordhaus, *Revisiting the Social Cost of Carbon*, www.pnas.org/content/114/7/1518.full, (2016).
[9] Electric Power Research Institute, *Understanding the Social Cost of Carbon: A Technical Assessment Executive Summary*, (2014).
[10] Greenstone, Michael*, Kopitsy, Elizabeth, and Wolvertony, Ann, *Developing a Social Cost of Carbon for US Regulatory Analysis: A Methodology and Interpretation,* http://isites.harvard.edu/fs/docs/icb.topic1186096.files/Session%206/Greenstone%20Developing%20a%20Social%20Cost%20of%20Carbon.pdf

concentrations of CO_2 are uncertain, the GCM simulation outputs are sensitive to inputs and create a range of estimates regarding environmentally responsible anthropogenic CO_2 emission levels and trajectories through time. This framework generated policy approaches involving goals and timetables for CO_2 emission reductions from specified base year levels ranging from the 22 Gt by 2040 scenario developed in this study to the IPCC 2.6 Representative Concentration Pathway scenario involving a goal of net zero anthropogenic GHG emissions by around 2065.[11]

A third framework involves setting limits on global warming temperature increases. Although this framework can establish clear temperature goals, the framework leaves the approaches and metrics unspecified. For example, the Paris Climate Agreement goal is to limit the impact of global warming to less than a 2-degree Celsius increase from pre-industrial average global temperatures.

A fourth framework involves command and control energy sector transformation. The approach involves mandates and subsidies to drive a shift toward a lower carbon state-of-technology in addition to shifting resources to R&D programs to accelerate technological innovation. This approach sets penetration rate and timetable policy goals for selected "clean energy" technologies. For example, California set a policy goal to achieve a 50 percent renewable generation share by 2030.

The four frameworks to formulate solutions to the global warming problem are not inherently contradictory. Setting a global CO_2 emission charge based on a cost benefit approach could conceivably result in the equilibration of anthropogenic CO_2 emission sources and sinks at a level sufficient to stabilize atmospheric concentrations of CO_2 at levels that prevent global temperature increases from exceeding policy goals. In addition, the command and control framework could, in theory, generate the same changes that would arise from economic activity coordinated by a global anthropogenic CO_2 emission charge.

Currently, the four frameworks are misaligned and contradictory. The current SCC policy goals generally produce anthropogenic CO_2 emission levels that are higher than the emission source and sink equilibrium goals, and produce expected average global temperature increases that are higher than the temperature threshold framework goals. Similarly, significant differences exist between the marginal costs of command and control climate based policies across regions, countries, and sectors indicating a divergence to the least-cost pathway to lowering CO_2 emission footprints coordinated by an anthropogenic CO_2 emission charge.

The current misalignment of climate policy frameworks means that implementing current climate policies initiatives will result in future global anthropogenic CO_2 emission reductions costing more than is necessary. Reframing climate policy initiatives in the electricity sector can help to align climate policy frameworks. This study tries to help align frameworks by:

- Employing the anthropogenic CO_2 emission charge approach of the first framework (balancing costs and benefits) to map the least cost pathway to reducing future CO_2 emission footprints.
- Employing emission reduction policy metrics arising from aligning the second framework (equilibrating CO_2 emission sources and sinks) and third framework (limit global temperature increases).
- Provide a policy mix benchmark for the fourth framework (command and control).

[11] IPCC, 2014: Summary for Policymakers, In: Climate Change 2014, Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Edenhofer, O., R. Pichs-Madruga, Y. Sokona, E. Farahani, S. Kadner, K. Seyboth, A. Adler, I. Baum, S. Brunner, P. Eickemeier, B. Kriemann, J. Savolainen, S. Schlömer, C. von Stechow, T. Zwickel and J.C. Minx (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

Reframing climate policy frameworks is important because the evolution of climate policies created misalignments that constitute one of the primary reasons for overall global climate policy underperformance, including the shortfalls in electric sector climate policy initiatives.

Climate policy evolution

The nature and scope of the problem drove the United Nations to respond by forming the Intergovernmental Panel on Climate Change (IPCC) in 1988. The IPCC initiated a series of periodic meetings and published a series of assessments. Toronto hosted one of the earliest international meetings on climate change in 1988, followed by the 1992 UN Conference on Environment and Development in Rio. The Rio meeting set up the United Nations Framework Convention on Climate Change that sought coordinated multi-lateral climate policy formulation to prevent the likelihood that global warming will produce dangerous interference with the global climate system. Subsequent meetings among the parties to the convention focused on climate policy targets and timetables. The first Conference of Parties (COP) meeting was in Berlin during 1995, followed by the 1996 COP2 meeting in Geneva, and the 1997 COP3 meeting in Kyoto. The Kyoto meeting produced the Kyoto Protocol—an international treaty framework to reduce baseline GHG emissions. More COP meetings followed and the COP 16 meeting produced the Cancun Agreement among 196 Parties with the goal of limiting the expected impact of anthropogenic GHG emissions to two degrees Celsius.

The 2-degree Celsius climate target reflects a range of GCM simulations estimating the linkages between anthropogenic CO_2 emissions and the global climate. Since climate analyses are stochastic, climate scientists use language that reflects uncertainty and assert that a greater than 2-degree Celsius increase in the average global temperature from pre-industrial levels ***will likely*** produce dangerous interference with the global climate.[12] Climate scientists also estimate that atmospheric concentrations of CO_2 between 430 to 500 ppm ***are more likely than not*** to limit the expected impact of global warming to 1.5 to two-degrees Celsius relative to pre-industrial levels.[13]

In 2015, the COP 21 meeting produced the Paris Climate Agreement that increased the climate policy ambition of the Cancun Agreement from limiting global warming to an increase of two degrees Celsius, to limiting global warming to an increase "well below" two degrees Celsius. This increase in policy ambition emerged despite two decades of efforts that had failed to halt the increases in atmospheric concentrations of CO_2.

Past policy shortcomings shaped a key attribute of the COP 21 Paris Agreement. Recognition of the failure of the Kyoto Treaty shifted the COP 21 approach away from negotiating binding treaty obligations and toward a new approach relying instead on social pressure to spur political actions that eventually drive GHG emission levels down enough to achieve climate policy targets. Social pressure arises from influencing public opinion in political and economic spheres. Social pressure influences the political agenda, and thus affects election outcomes as well as the formulation and implementation of domestic legislation and regulations. In addition, social pressure drives non-political activities ranging from corporate sustainability actions to shareholder activism initiatives.

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[12] IPCC 2014: *Climate Change 2014: Synthesis Report, Contributions of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Core Writing Team, R.K. Pachauri and L.A. Meyer 9eds.). IPCC, Geneva, Switzerland

[13] IPCC, 2014: Summary for Policymakers, In: Climate Change 2014, Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Edenhofer, O., R. Pichs-Madruga, Y. Sokona, E. Farahani, S. Kadner, K. Seyboth, A. Adler, I. Baum, S. Brunner, P. Eickemeier, B. Kriemann, J. Savolainen, S. Schlömer, C. von Stechow, T. Zwickel and J.C. Minx (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

The interactions of two key elements in the Paris Climate Agreement generate social pressure. First, parties to the agreement publicly pledged Intended Nationally Determined Contributions (INDCs) to GHG emission reductions. Only ten of the 196 nations that are parties to the agreement failed to make voluntary pledges that became the Nationally Determined Contribution (NDC) to alter GHG emissions when the Paris Climate Agreement achieved ratification in October of 2016. Second, countries accepted an obligation to provide information creating transparency in monitoring, reviewing and verifying efforts to achieve their NDC pledges.

The Paris Agreement employs transparency to drive accountability to pledges. Therefore, the rules setting procedural requirements for transparency are perhaps the most important aspect of the Paris Climate Agreement. Compliance with transparency rules will feed an international assessment process scheduled every five years, beginning in 2018, called “stocktakes” to measure and report progress on achieving NDCs and to encourage efforts to ratchet up NDCs.

The Paris Climate Agreement has the potential to generate social pressure when the transparency process makes it clear that some countries are delivering or exceeding their NDC pledges, while others are not. In a globally competitive economy, countries that incur costs to meet their NDCs will likely feel unfairly disadvantaged, and thus are likely to put pressure on countries that do not deliver on their NDCs to redouble their efforts or face consequences, ranging from jawboning to actions such as trade restrictions. Thus, the design of Paris Agreement generates peer pressure and tries to make the international community hold each other accountable for delivering NDCs.

The United Nations notes that even if all countries deliver on their current pledges, expected global GHG emissions will increase from the current 44.8 to 55 Gt CO_2e by 2030.[14] Therefore, the Paris Climate Agreement also employs social pressure to ratchet up NDCs through time by identifying best practices in countries that meet or exceed their NDCs and to generate social pressure on other parties to follow these examples. The bottom line is that the Paris Climate Agreement can only work if some countries lead by example and deliver on a sequence of increasing ambitious NDCs.

The Paris Climate Agreement does not specify the size or timing involved in ratcheting up CO_2 emission reduction commitments for any countries. The Paris Agreement also does not specify an annual anthropogenic CO_2 emission level that aligns with the climate policy goal of stabilizing atmospheric concentration of CO_2 at a level that limits the expected impact of GHG emissions to an increase well below two degrees Celsius from pre-industrial average global temperatures. However, the Paris agreement does specify how to accomplish the climate policy goal. As Figure 2 shows, the Paris Climate Agreement seeks to balance anthropogenic CO_2 emission sources and sinks by the second half of the century to stabilize atmospheric concentrations of GHG at a level that, more likely than not, generates a temperature increase of less than two degrees Celsius from pre-industrial levels.

[14] United Nations Framework Convention on Climate Change/CP/2015/L.9/Rev.1, December 12, 2015

FIGURE 2

The Paris Agreement

"[…]Holding the increase in the global average temperature to well below 2 °C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5 °C above pre-industrial levels, recognizing that this would significantly reduce the risks and impacts of climate change[…]"
-Article 2, Section 1a
"In order to achieve the long-term temperature goal set out in Article 2, Parties aim to reach global peaking of greenhouse gas emissions as soon as possible, recognizing that peaking will take longer for developing country Parties, and to undertake rapid reductions thereafter in accordance with best available science, so as to achieve a balance between anthropogenic emissions by sources and removals by sinks of greenhouse gases in the second half of this century, on the basis of equity, and in the context of sustainable development and efforts to eradicate poverty."
-**Article 4, Section 1**

Paris Climate Agreement based climate policy metrics

The Paris Climate Agreement focuses on balancing overall CO_2 emission sources and sinks in the carbon cycle. Over the past twenty-five years, increases in the annual anthropogenic CO_2 emission sources outpaced increases in the absorption capability of sinks. The resulting cumulative imbalance drove atmospheric concentrations of CO_2 up by 50 ppm to the current level of around 400 ppm. This level is more than 40 percent above average pre-industrial era level.

Anthropogenic CO_2 emissions sources in the carbon cycle increased from 24.3 to 35.7 Gt CO_2 between 1990 and 2015. [15] CO_2 emission sinks in the carbon cycle also increased over the past twenty-five years, due in part, to the increased atmospheric concentrations of CO_2 causing a "greening" effect around the globe.[16] The implication is that the removal rate of atmospheric CO_2 is positively related to the level of atmospheric concentrations.

Climate scientists estimate that CO_2 sinks currently remove about 45 to 60 percent of 36 Gt of annual anthropogenic CO_2 emissions.[17] Achieving the 2-degree Celsius target of 450 ppm atmospheric concentration of CO_2 involves stabilization of

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[15] World Resources Institute, *Total GHG emissions excluding land-use change and forestry – 2012*. CAIT – Historical Emissions Data (Countries, U.S. States, UNFCCC). CAIT data browser, http://www.wri.org/resources/data-sets/cait-historical-emissions-data-countries-us-states-unfccc

[16] The Economist, *Days of the Triffids*, November 12, 2016, pg. 72.
[17] Quere, C.L.E. et al. Global Carbon Budget 2015, Earth Syst. Sci. Data 7, 349-396 (2015).

atmospheric concentrations of CO_2 above the current level of 400 ppm and thus would likely involve carbon sinks toward the higher end of the range of current absorption capabilities. Therefore, if CO_2 emission sinks could remove 60 percent of anthropogenic CO_2 emissions sources, then a reduction from the current 36 Gt level of annual anthropogenic CO_2 emissions to around 22 Gt would equilibrate anthropogenic sources to the absorption capacity of sinks. The implication is that achieving such a balance before atmospheric concentrations of CO_2 reach the 450 to 500 ppm level would stabilize the carbon cycle at a point that, more likely than not, limits the expected impact of global warming to 1.5 to 2.0-degree Celsius increase relative to pre-industrial levels.

This two-degree Celsius scenario target of 22 Gt of anthropogenic CO_2 emissions by 2040 ("22 Gt by 2040") aligns with the more complex climate analysis conducted by Pakala and Socolow showing that anthropogenic carbon emissions of 7 billion tons (CO_2 is 3.67 times the tons of carbon) or 25.7 Gt CO_2 would stabilize the atmospheric concentrations of CO_2 around 500 ppm (+/- 50 Gt).[18]

If current CO_2 emission trends continue, then atmospheric concentrations of CO_2 will exceed the 450-ppm threshold by the year 2040. Therefore, the next 25 years presents an available window of opportunity to reduce anthropogenic CO_2 emission sources to around 22 Gt and equilibrate anthropogenic sources with the capacity of sinks and stabilize atmospheric concentrations of CO_2 at or below the 450 to 500 ppm mark. Therefore, setting a climate policy target to 22 Gt by 2040 aligns with the ambition to equilibrate sources and sinks to limit the expected impact of global warming to a two-degrees Celsius increase from pre-industrial levels.

Climate policy challenge: Closing CO_2 emission footprint gaps within the window of opportunity

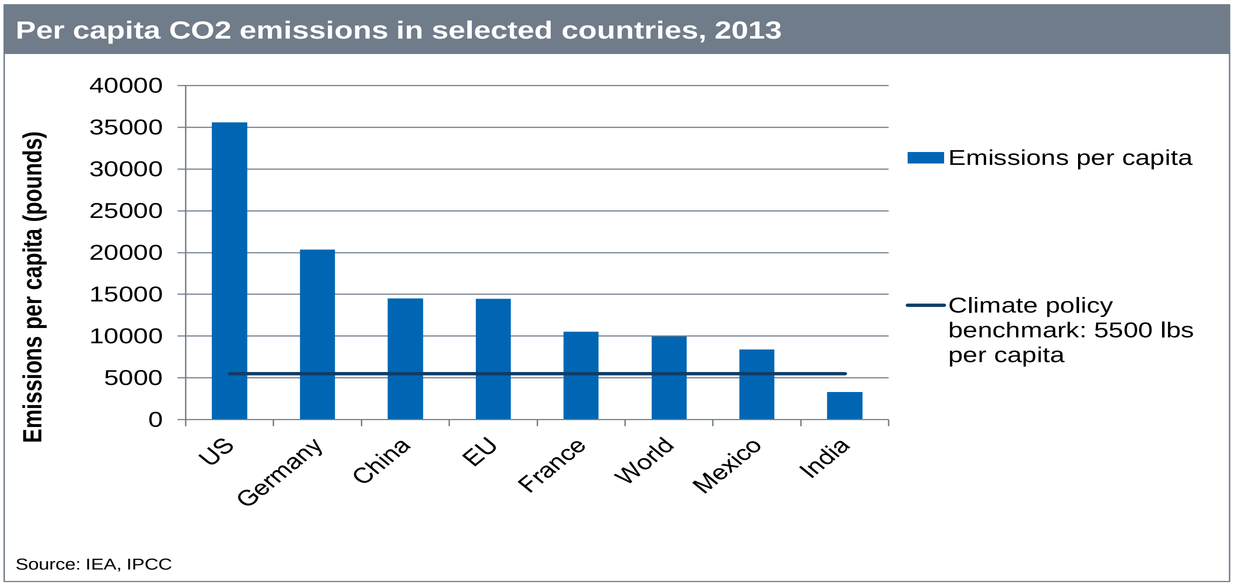
The climate policy challenge involves closing the gap between the world's annual anthropogenic CO_2 emissions and the absorption capability of CO_2 sinks by 2040. However, existing sources of anthropogenic CO_2 emissions are not evenly distributed around the globe. Therefore, the burden of CO_2 emissions reductions are also not evenly distributed among nations with different populations at different stages of economic development.

A starting point to compare and to contrast national climate policy targets involves translating the overall 22 Gt anthropogenic CO_2 emission 2040 goal into a per capita annual CO_2 emission footprint target. The 7.2 billion people currently on earth produce annual anthropogenic CO_2 emissions of 10,933 lbs. per capita. [19] Looking ahead, global population is likely to increase to around 9 billion people by 2040.[20] Therefore, the annual anthropogenic emission target reflecting the 22 Gt target translates into an annual per capita target of around 5,500 pounds of anthropogenic CO_2 emissions.

The annual per capita CO_2 emission footprint target provides insight into how heterogeneous the associated climate policy challenge is among nations. Figure 3 shows per capita CO_2 emissions for selected countries in relation to the policy goal of 5,500 lbs. annual CO_2 emissions per capita.

[18]S. Pacala and R. Socolow, Stabilization Wedges: Solving the Climate Problem for the Next 50 Years with Current Technologies, *Science*, 13 August, 2004.
[19] One metric ton equals 2205 pounds
[20] United Nations Department of Economic and Social Affairs, www.un.org/en/development/desa/news/population/UN-report-world-population-projected-to-reach-9-6 billion-by-2050-html

FIGURE 3



The annual US per capita CO_2 emission footprint puts former US President Barack Obama's climate policy ambitions into perspective. President Obama addressed the 2009 COP 19 meeting in Copenhagen and pledged to the global community that the US would reduce its CO_2 emissions by 80 percent from 1990 levels by 2050. [21] This pledge aligns with the 5,500 annual CO_2 emission policy target because US CO_2 emissions in 1990 were 5.1 Gt and an eighty percent reduction would lower annual CO_2 emissions to just over 1 Gt, and distributing this emission level over a US population that is expected to increase from 323 to 400 million people between now and 2050 yields an emission target of 5,500 lbs. annual CO_2 emissions per capita in 2050.[22] Since current US CO_2 emissions are about the same as the 1990 level, this climate policy ambition involves an 84 percent reduction--from about 35,000 lbs. annual CO_2 emissions per capita--between now and 2050.

President Obama's US climate policy ambition involved a percentage reduction in the annual CO_2 emission per capita footprint that is over twice what would be required for the global average percentage reduction by 2050. This difference is not surprising because with few exceptions, national gaps between CO_2 emissions per capita and the climate policy target of 5,500 lbs. per year reflect the linkages between economic development, primary energy consumption, and CO_2 emissions.

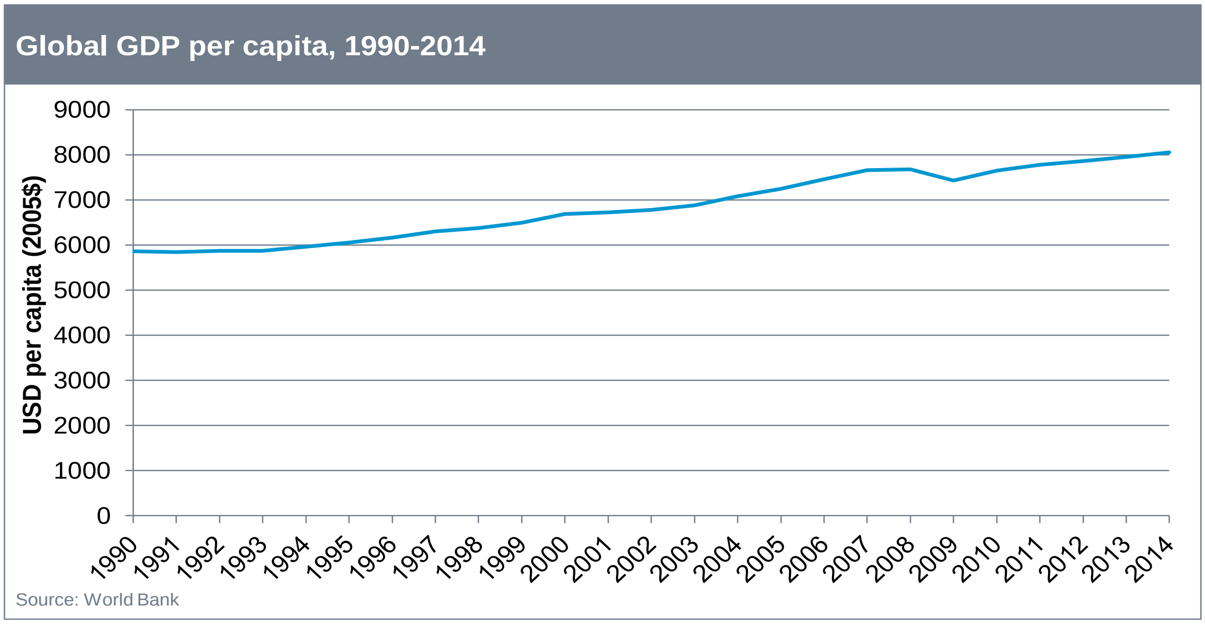
Primary energy consumption linkage to economic development

[21] President Barack Obama, address to the 19th Conference of Parties meeting to the United Nations Framework Agreement on Climate Change, Copenhagen, Denmark, December 18, 2009.

[22] US Census Bureau, Projections of the Size and Composition of US Population: 2014 to 2050, Current Population Reports, March 2015. (http://www.census.gov/content/dam/Census/library/publications/2015/demo/p25-1143.pdf?)

In the past 25 years, economic development drove a one-third increase in global GDP per capita, as shown in Figure 4.

FIGURE 4



National income per capita indicates the level of economic development. Figure 5 shows the positive relationship between national income per capita and primary energy use. The strength of this relationship causes differences in national income per capita to account for almost half of the variation observed from one country to the next in primary energy use per capita. As a result, the lack of a current national gap to the 5,500 CO_2 emission footprint target typically reflects a lack of access to modern energy services.

FIGURE 5

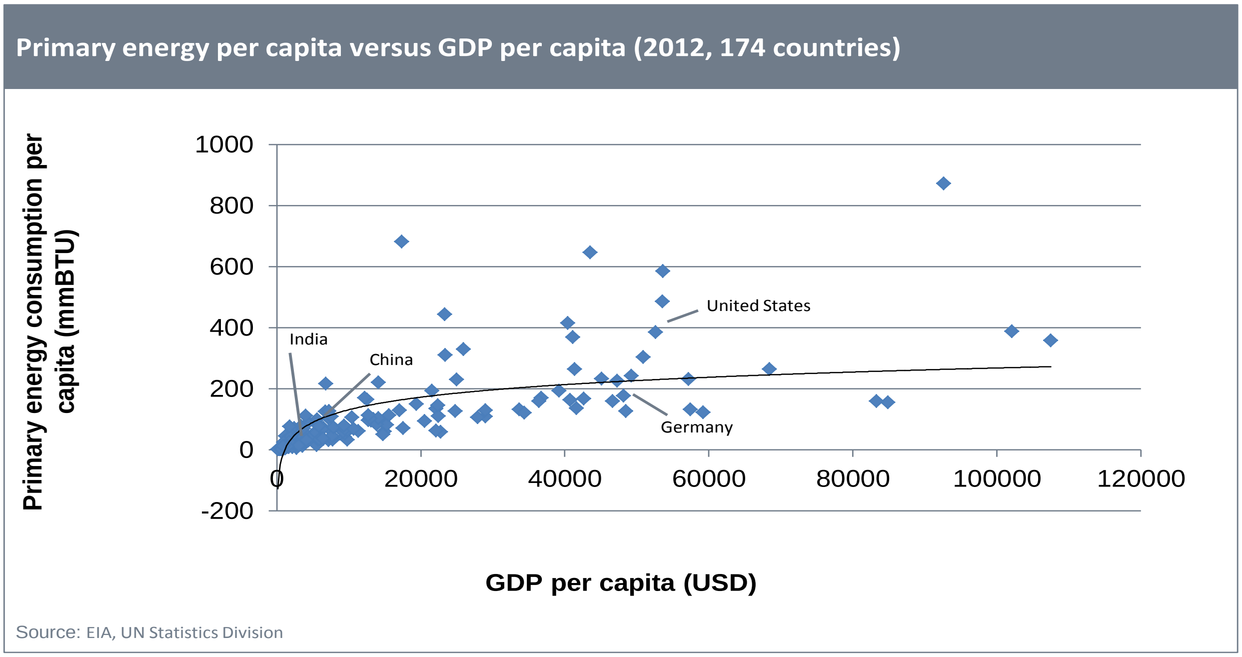


Figure 6 shows a regression that fits a curve to the data shown in Figure 5 to quantify the positive but declining relationship between per capita primary energy consumption and income. The Multiple-R statistic indicates a high degree of correlation between the dependent variable actual values and the values produced by the equation. The F-statistic indicates that the estimated equation provides statistically significant explanatory power because the probability that no relationship exists between the dependent and the independent variables is less than 1 percent. The adjusted R-Square statistic indicates that the correlation between the dependent and independent variable in the estimated equation explains close to half of the observed variation among national energy consumption per capita observations.

FIGURE 6

Primary energy use and GDP per capita						
SUMMARY OUTPUT						
Regression Statistics						
Multiple R	0.686510318					
R Square	0.471296417					
Adjusted R Square	0.46551607					
Standard Error	122.2631143					
Observations	174					
ANOVA						
	df	SS	MS	F	Significance F	
Regression	1	2305254.594	2305254.594	154.2154864	1.0903E-25	
Residual	173	2586050.559	14948.26913			
Total	174	4891305.154				
	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	0					
ln(GDP/capita)	13.02176249	1.048590155	12.41835281	1.00175E-25	10.9520853	15.09143969

This relationship between primary energy use and GDP per capita is consistent with the interpretation that consumers initially place a high priority on increasing energy use relative to increasing the consumption of other goods and services when income gains from economic development provide the purchasing power to afford modest modern lifestyles. However, once energy consumption reaches a level that covers basic energy service necessities, the relative importance of increasing purchases of energy versus other goods and services declines with further gains in purchasing power.

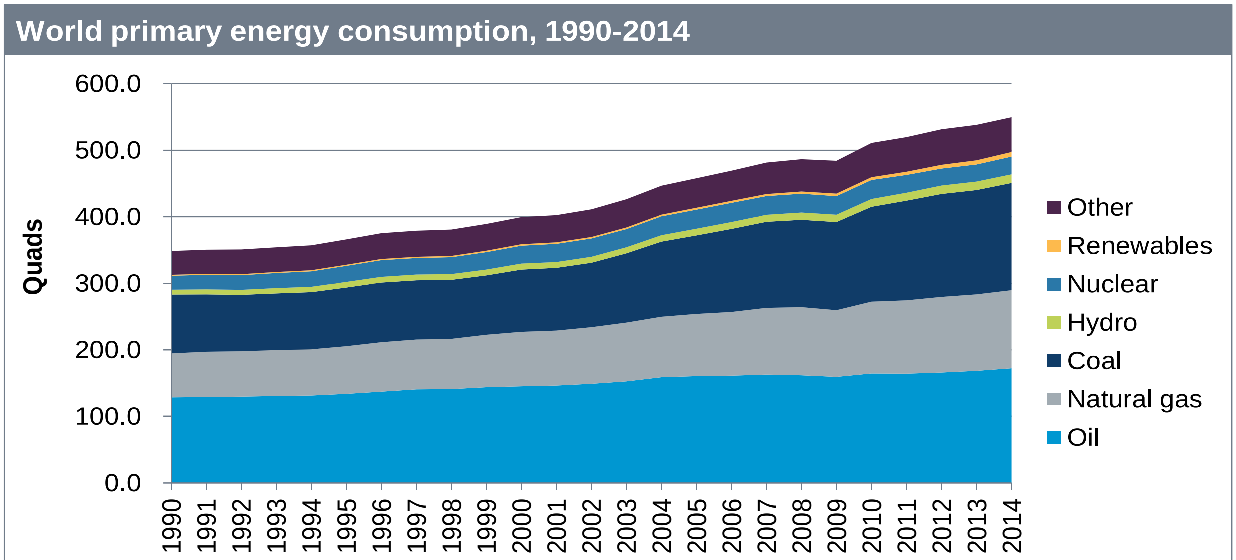
The priority on energy consumption in the early stages of economic development will likely continue because energy is a necessity of a modern lifestyle. As a result, increasing energy use is inherent to achieving important public policy goals. The International Covenant on Economic, Social and Cultural Rights includes access to a minimum amount of energy as a basic human right. [23] Six years ago, the Secretary General of the United Nations set a human rights goal for universal energy access by 2030. And promoting economic development has proven to be an effective way to expand energy access and reduce energy poverty. The 33 percent gains in global GDP per capita from 1990 to 2010 caused a decline from 59 to 47 percent in the share of the global population relying on solid fuels as their primary energy source as well as an increase in the share of the global population with access to electricity from 70 to 83 percent. [24]

The linkage between economic development and greater energy consumption is well-established. In the past 25 years, the one-third increase in global GDP per capita drove a 60 percent increase in primary energy consumption, as shown in Figure 7.

[23] The International Covenant on Economic, Social and Cultural Rights, adopted by the United Nations General Assembly on 16 December 1966 and entered into force on 3 January 1976

[24] International Energy Agency, *Global Tracking Framework*, 2013

FIGURE 7

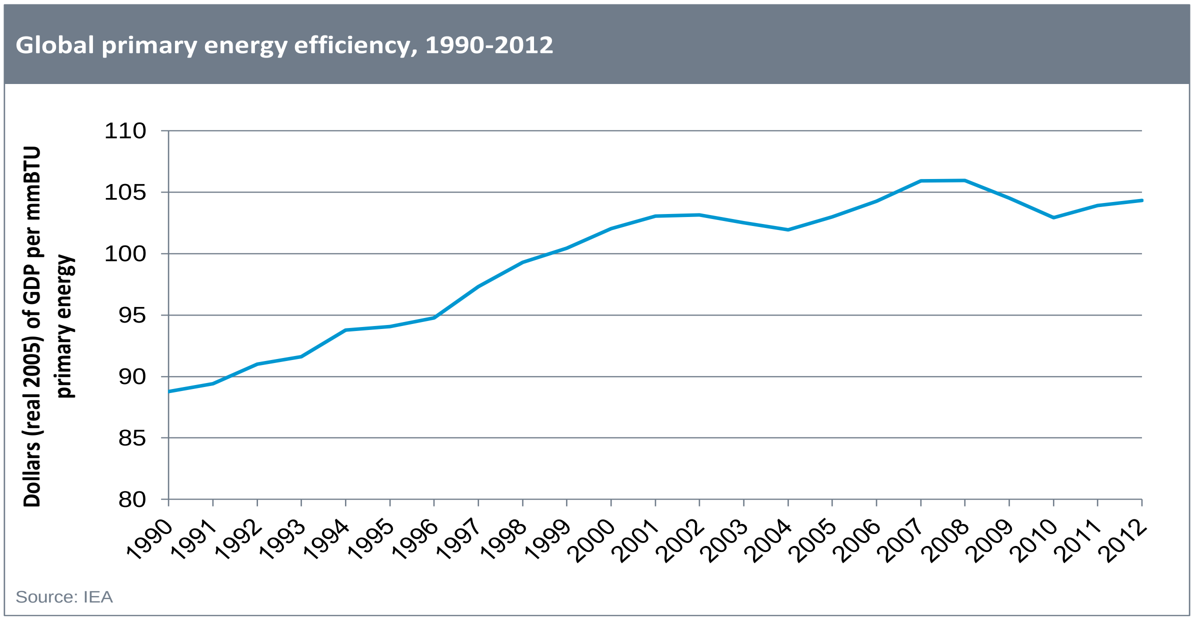


Notes: Renewables include solar, wind, geothermal, and tide/wave/ocean energy. Other includes biofuels, solid waste, biomass, and net trade of electricity and heat.
Source: IEA

Past increases in energy use outpaced increases in economic activity because economic growth in developing economics outpaced developed economies. This linkage is likely to continue if economic development broadens economic well-being in the decades ahead. Most of the world's population lives in developing economics where a one percent gain in income per capita from a starting point equal to the current world average income per capita imply a percentage increase in primary energy use that is over twice the size of a similar one percent increase in income per capita at the current Organization of Economic Cooperation and Development (OECD) developed economy level of economic well-being.

Energy efficiency gains temper but do not de-link economic development from increased primary energy use. Energy efficiency in the production of goods and services is the ratio of energy end use outputs to energy inputs. Therefore, changes in this ratio reflect changes in the energy input requirements of the technologies employed to produce goods and services. Figure 8 shows primary energy efficiency improvements of about 0.8 percent per annum over the past 25 years.

FIGURE 8

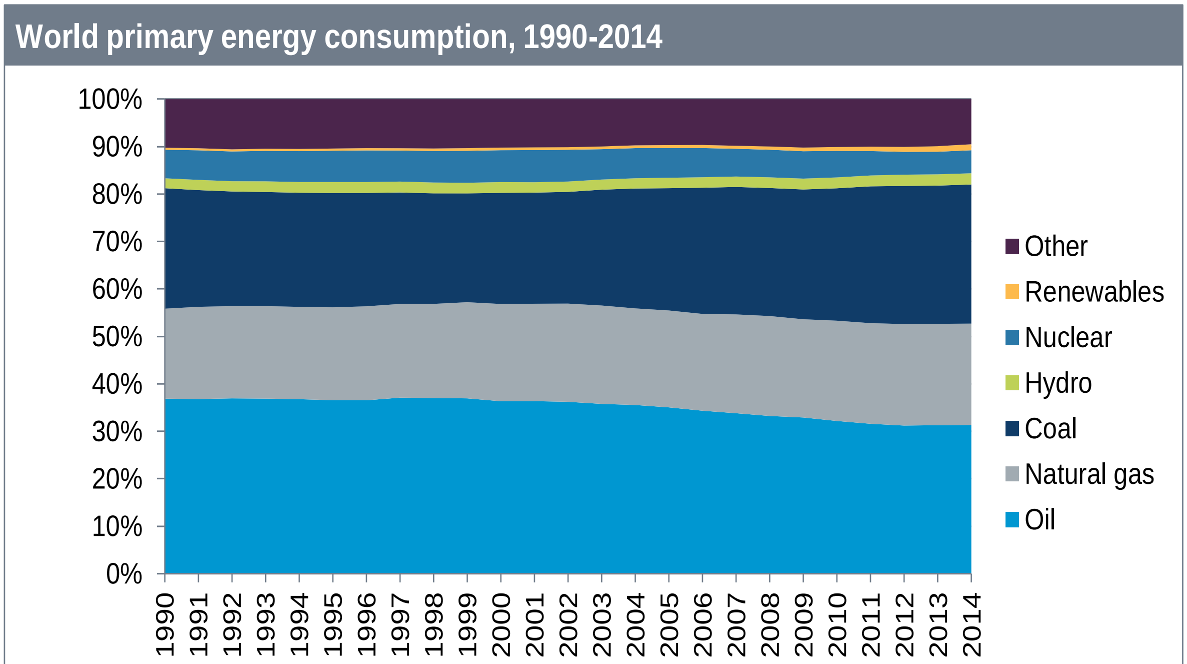


Looking ahead across the next several decades, continued economic development will predictably drive increases in global income per capita and thus drive primary energy consumption upward, albeit tempered by energy efficiency gains.

CO_2 emissions linkage to primary energy consumption

Figure 9 shows the gradual evolution in the primary energy mix across the past twenty-five years. Energy use is predictable in the short-run because the level and mix of primary energy inputs reflect the existing state of technologies employed to produce goods and services at all levels of economic development. Although some fuel flexibility exists in some technologies, fuel input requirements for existing technologies are rigid because most technologies are linked to a fuel and fuel input rate in production functions.

FIGURE 9



Notes: Renewables include solar, wind, geothermal, and tide/wave/ocean energy. Other includes biofuels, solid waste, biomass, and net trade of electricity and heat.
Source: IEA.

Rigidity in the mix of energy inputs to the existing capital stock generates changes in the primary fuel mix that are evolutionary rather than revolutionary. These rigidities persist for two reasons. First, the installed base of energy using capital stock is large and the annual turnover rate is relatively small because the economic life of the energy end use capital stock tends to typically span decades. Second, fossil fuel energy input characteristics such as cost, availability, and energy density drove advances in end use technologies over long periods of time and alternatives require similar long timeframes to move up experience curves and become viable competitive alternatives. The implication is that technology learning curves create inertia in technology selection because innovations take time to prove out, gain traction and diffuse into new and replacement capital stock decisions.

The CO_2 intensity of primary energy consumption is the weighted average of the carbon contents of the various primary energy sources shown in Table 1.

TABLE 1

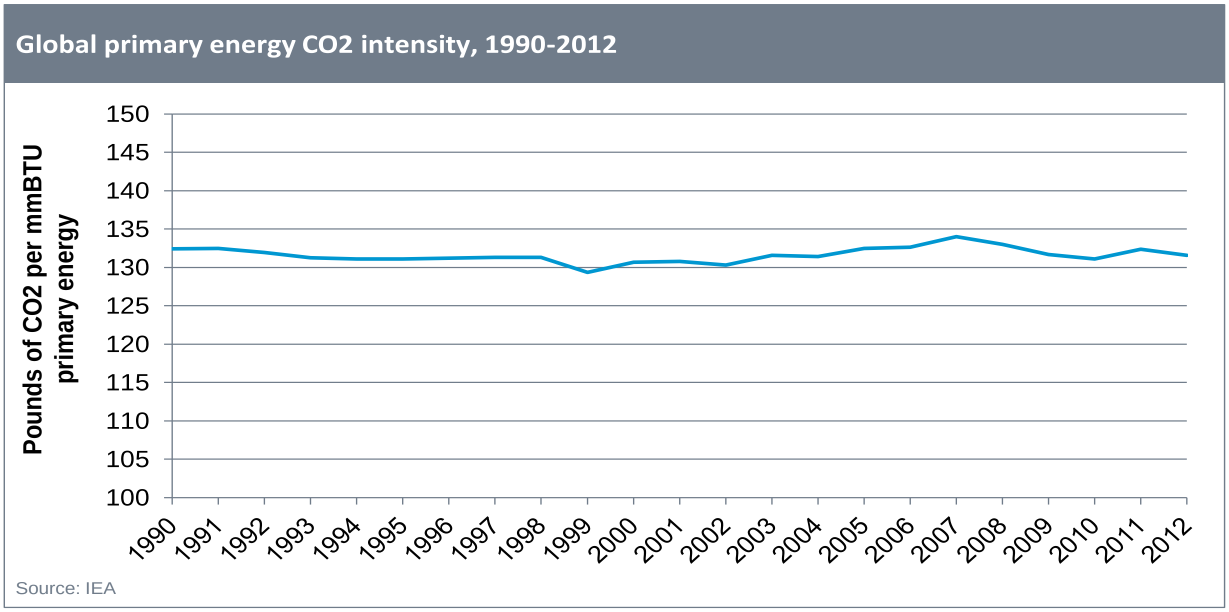
Primary energy carbon content

Primary energy type	Pounds CO2 per mmBTU
Renewables	0
Nuclear	0
Hydro	0
Coal	212.37
Natural Gas	158.29
Oil	169.45

Source: IPCC

Changes in the primary energy mix can create either increases or decreases in the overall carbon intensity of global energy consumption. For example, the non-hydro renewables share of primary energy inputs increased from 0.4% to 1.4% from 1990 to 2015 and generated downward pressure on the carbon intensity of primary energy consumption. Conversely, the increase from 25.4 to 28.9 percent in the coal share of the primary energy mix generated upward pressure on the carbon intensity of primary energy consumption. These offsetting forces caused the carbon intensity of the world's primary energy consumption, as shown in Figure 10, to remain stable across the past quarter century.

FIGURE 10



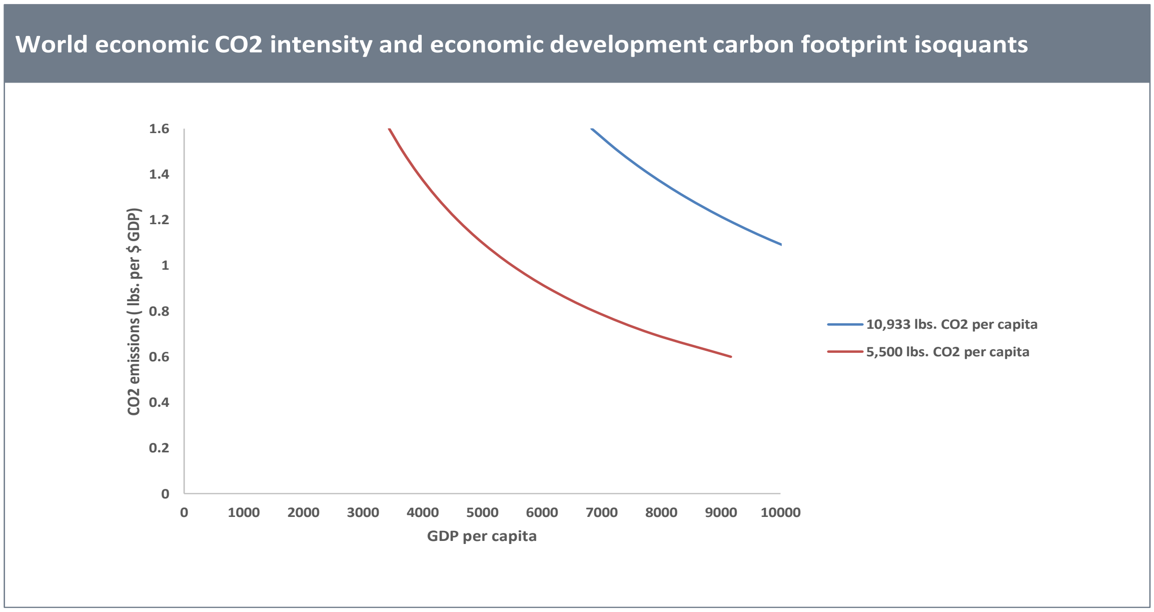
The bottom line is that the climate change poses a significant policy challenge without considering that most people on earth currently live in developing economies where energy poverty remains significant. A sustainable long-run solution to the climate policy challenge must account for economic development reducing energy poverty in the future. The implication is that a solution to the global warming problem requires creating an example for others to follow of a CO_2 emission footprint aligned with both the climate policy target as well as aligned to the energy needs of an increasingly widespread developed economy lifestyle.

CO_2 emission footprint analyses framework

Analyses of demand and supply side factors determining CO_2 emission footprints provide a framework to formulate climate policy initiatives to close the gaps between CO_2 emissions and climate policy targets within the available window of opportunity. In addition, tracking changes separately for demand versus supply side factors provides insights to evaluate the determinants of changes in CO_2 emission footprints and the impact of climate policy initiatives.

Climate policy targets expressed as CO_2 emission footprints (lbs. CO_2 per person per year) are the product of two factors. The first factor is annual GDP per person, a parameter measuring the stage of economic development. The second factor is the carbon intensity of economic activity (CO_2 emissions per dollar of GDP). The second factor reflects the characteristics of the stock of energy using technologies employed in the production of goods and services. These two factors trace out climate policy frontiers showing the combinations of GDP per capita and carbon intensity of GDP that produce the per capita CO_2 emission isoquants. For example, Figure 11 shows isoquants at the combinations of CO_2 emissions per dollar of GDP and the GDP per capita that produce the current average global CO_2 emission footprint of 10,933 lbs. CO2 emissions per capita per year. The 5,500 global CO_2 emission footprint policy metric is also shown, indicating that isoquants closer to the origin represent lower CO_2 emission footprints.

FIGURE 11



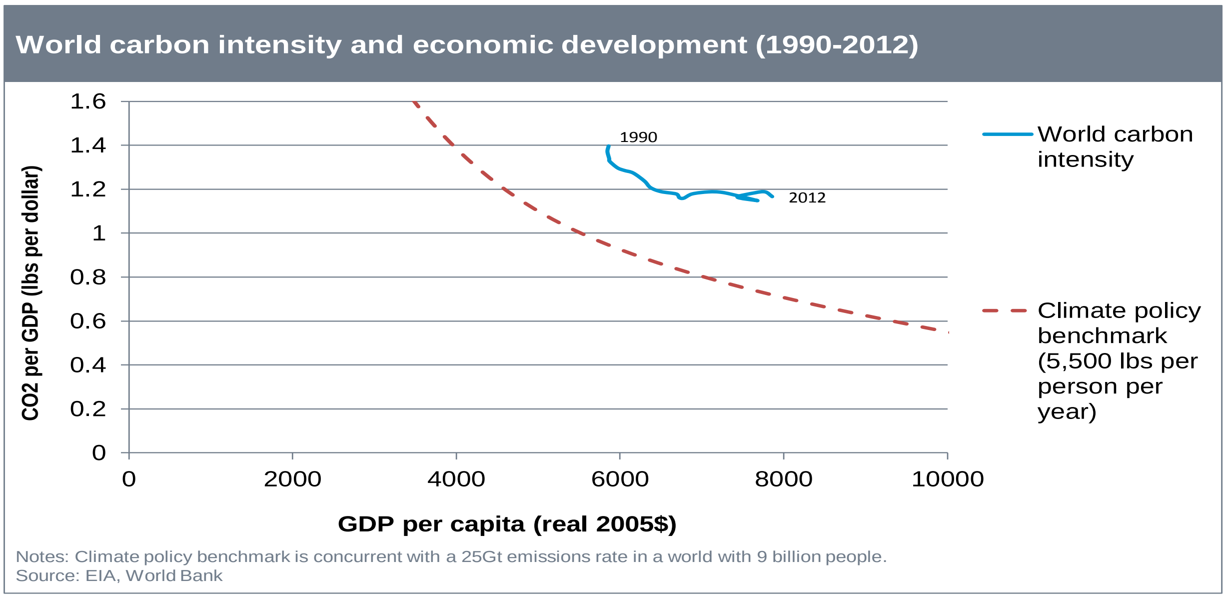
The gap between global annual per capita CO_2 emissions and an isoquant equal to a policy benchmark measures the size of the global climate policy challenge. Narrowing the distance between the actual per capita CO_2 emissions and the policy benchmark frontier indicates progress in solving the global warming problem.

The track record of changes in the gap between the world's per capita CO_2 emission and the per capita CO_2 emission policy frontiers provides a metric to assess international efforts to solve the global warming problem. An effective climate policy impact would narrow the gap through time at a pace that would close the gap by the second half of this century. Conversely, a widening of the gap indicates that climate policy is not making adequate progress in solving the global warming problem. If the gap is widening but at a slowing pace, then the possibility exists that a policy is starting to move in the direction of reducing the gap between anthropogenic CO_2 emission sources and sinks. However, at best such a result indicates that climate policy implementation is not yet solving the global warming problem and instead, is only slowing the rate at which the global warming problem is getting worse.

Assessing international climate policy initiatives

Assessing the impact of international climate policy initiatives over the past quarter century aligns with the time interval of international awareness of the problem and the track record of efforts to implement solutions to the global warming problem. Figure 12 shows the global climate policy track record. From 1990 to 2012, the gap between the global annual CO_2 emissions per capita versus the 5,500 annual lbs. CO_2 emission per capita climate policy frontier goal widened. The path of the global CO_2 emissions versus the climate policy frontier indicates that CO_2 emission footprints are increasing because the gains in GDP per capita are more than offsetting the declines in the CO_2 intensity of economic activity.

FIGURE 12



The track record of the past twenty-five years indicates that international climate policy initiatives are not solving the global warming problem and past efforts are at best, only slowing the rate at which the global warming problem is worsening. This CO_2 emission footprint analysis framework provides a harsh assessment of climate policy initiatives over the past quarter century. Yet his assessment aligns with the November 2015 Economist Magazine Special Report, *Climate Change* which also noted that the steady increase in GHG emissions as well as the collapse of the Kyoto Protocol, and concluded that, “Not much has come of efforts to prevent climate change so far.”

Recognition of the size of the current gap between global average per capita CO_2 emissions and policy goal is important because all too often, climate policy initiatives fail to scale policy objectives to the size of the problem. Using metrics that are not calibrated to the size of the problem can yield the false impression of policy success based on the premise that “every little bit helps.” From this perspective, past international climate policy initiatives have been successful in lowering CO_2 emissions from what they otherwise would have been. Yet, when evaluation metrics reflect emission reductions from a baseline projection of increasing emissions, the potential exists for the metric to indicate signs of policy progress even as the global warming is getting worse.

The big picture shows that if the future involves lower energy poverty and higher average global GDP per capita, then formulating climate policies that can close the gap between the capita CO_2 emission footprints associated with developed economy life styles and the 5,500 annual lbs. CO_2 emissions per capita target within the twenty-five years must accommodate the linkages between economic development, primary energy consumption and CO_2 emissions.

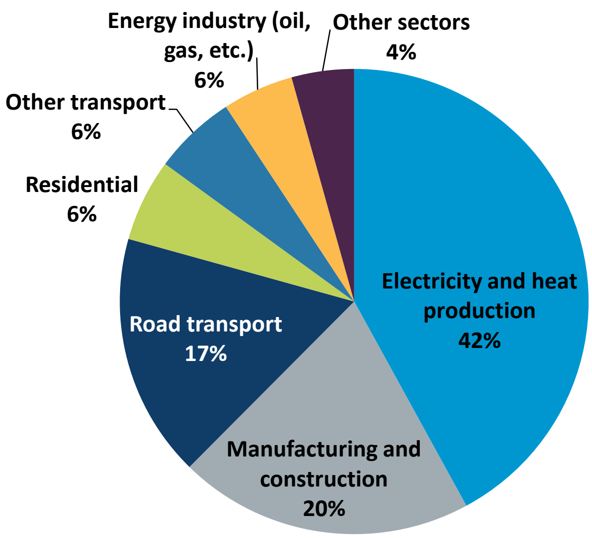
Chapter 2: Focusing on the electricity sector climate policy challenge

Electricity sector CO_2 emissions

A significant reduction in the CO_2 emissions from the world's electricity sector is a necessary part of any solution to the global warming problem. Figure 13 shows a breakdown of CO_2 emissions across global economic sectors. Fossil-fueled electricity production currently accounts for about one-third of overall annual global anthropogenic CO_2 emissions.

FIGURE 13

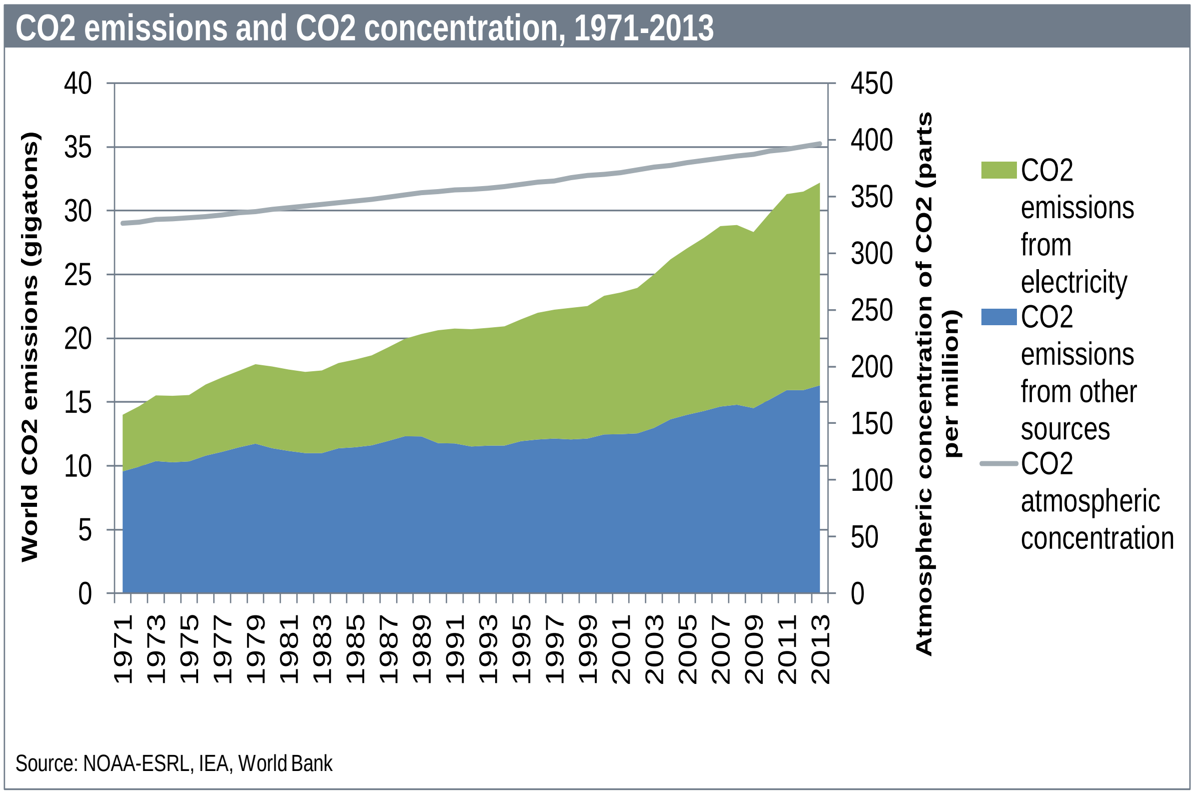
CO_2 emissions by sector, 2012 (31.73 gigatons total)



Source: International Energy Agency (IEA)

Electricity sector CO_2 emissions are one of the fastest growing sources of GHG emissions and Figure 14 shows how electricity sector CO_2 emissions outpaced overall anthropogenic CO_2 emissions over the past 45 years.

FIGURE 14

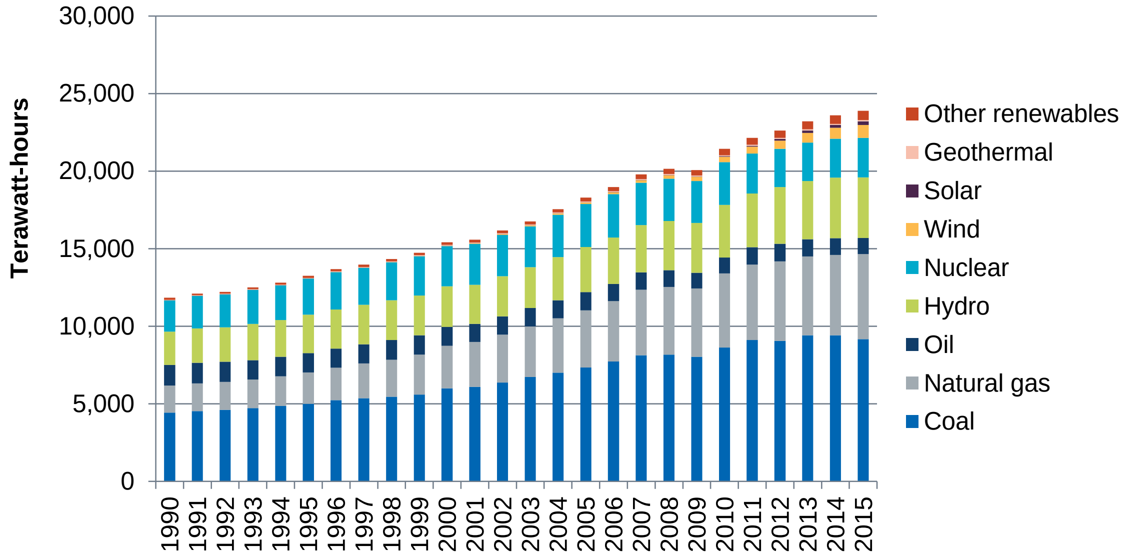


Primary energy consumption linkage to electricity consumption

Primary energy consumption increases with electricity consumption because electric energy is simply a transformation of primary energy into another energy form. Fossil fuels account for most global electric production and these electric generating technologies typically operate for 25 to fifty years. Fossil fuels are an economic input to electric production and involve relatively rigid fuel input requirements. These characteristics drive the slow evolution of the primary fuel mix of the global power production, shown in Figure 15.

FIGURE 15

World electricity generation, 1990-2015



Source: IEA

Electricity consumption linkage to economic development

The link between increased electricity consumption and greater worldwide economic development accounted for the doubling of global electric production over the past 25 years. Figure 16 illustrates the relationship between per capita national income and electricity use, while Figure 17 shows the regression that fits a curve to the data. The Multiple-R statistic indicates a high degree of correlation between the dependent variable actual values and the values produced by the equation. The F-statistic indicates that the estimated equation provides statistically significant explanatory power because the probability that no relationship exists between the dependent variable and the independent variables is less than 1 percent. The adjusted R-Square statistic indicates that the estimated equation explains over half of the observed variation among the observed per capita electricity consumption based on the relationship to national income per capita.

This relationship is consistent with the interpretation that consumers initially place a high priority on increasing electricity use relative to increasing the consumption of other goods and services when income gains from economic development provide the purchasing power to afford modest modern lifestyles. However, once electricity consumption reaches a level that covers basic energy service necessities, the relative importance of increasing purchases of electricity services versus other goods and services declines with further gains in purchasing power.

FIGURE 16

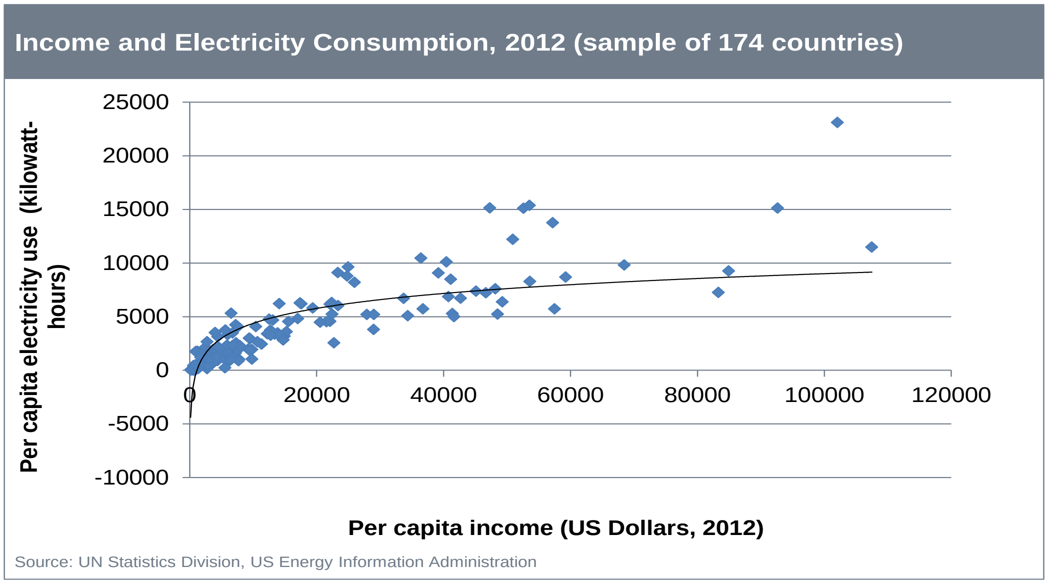


FIGURE 17

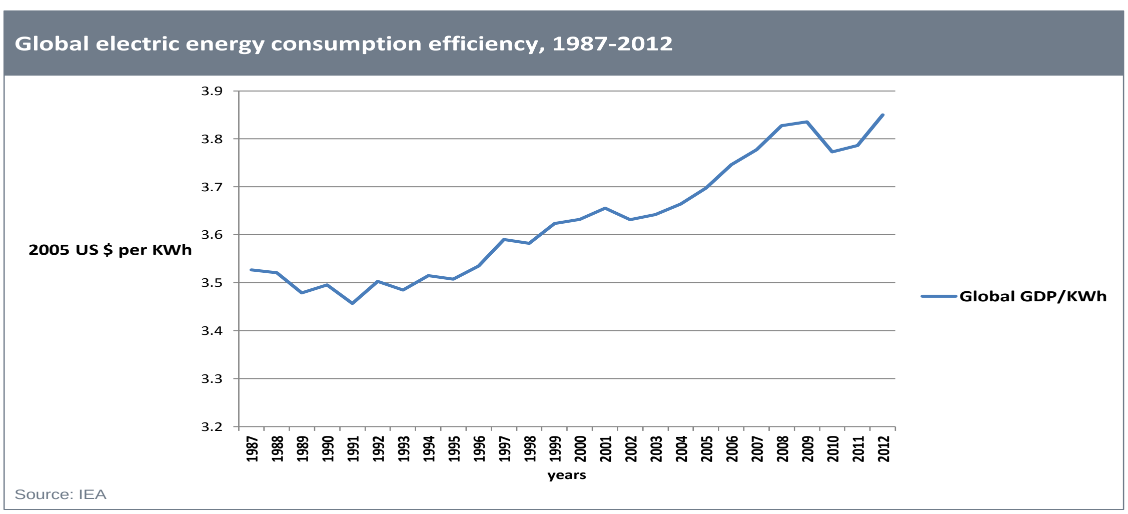
Electricity use and GDP per capita

SUMMARY OUTPUT						
Regression Statistics						
Multiple R	0.755853803					
R Square	0.571314972					
Adjusted R Square	0.565534625					
Standard Error	3316.316436					
Observations	174					
ANOVA						
	df	SS	MS	F	Significance F	
Regression	1	2535685100	2535685100	230.5596966	1.38921E-33	
Residual	173	1902646164	10997954.71			
Total	174	4438331264				
	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	0					
ln(GDP/capita)	432.4708875	28.48165238	15.18419232	1.20774E-33	376.2546184	488.6871566

About 17% of the world's population does not currently have access to electricity.[25] The relationship between national income per capita and electricity use indicates electric consumption will increase faster if economic development reduces electric energy poverty and broadens economic well-being by distributing disproportionate income per capita gains to the developing versus the developed world economies.

The ratio of GDP to electricity consumption reflects the linkage between economic development and electric energy inputs. Electric energy efficiency in the production of goods and services is the ratio of electric energy end use outputs to energy inputs. Therefore, changes in this ratio reflect changes in the electricity input requirements associated with the technologies used to produce goods and services. The economic operating lives of electric end uses average more than a decade and the end use technology turnover rate influences electric consumption efficiency trends. However, in the short-run, changes in consumption efficiency reflect the impact of the business cycle altering electric end use utilization rates. Figure 18 shows short run variations in efficiency levels as well as the long-run electric efficiency improvement trend of about 0.25 percent per annum over the past 25 years. These efficiency gains tempered but did not come close to de-linking economic development from increased electric consumption.

FIGURE 18



Looking ahead across the next several decades, continued economic development will predictably drive increases in global income per capita and thus drive electricity consumption upward, albeit tempered, but not delinked, by continued electricity consumption efficiency gains.

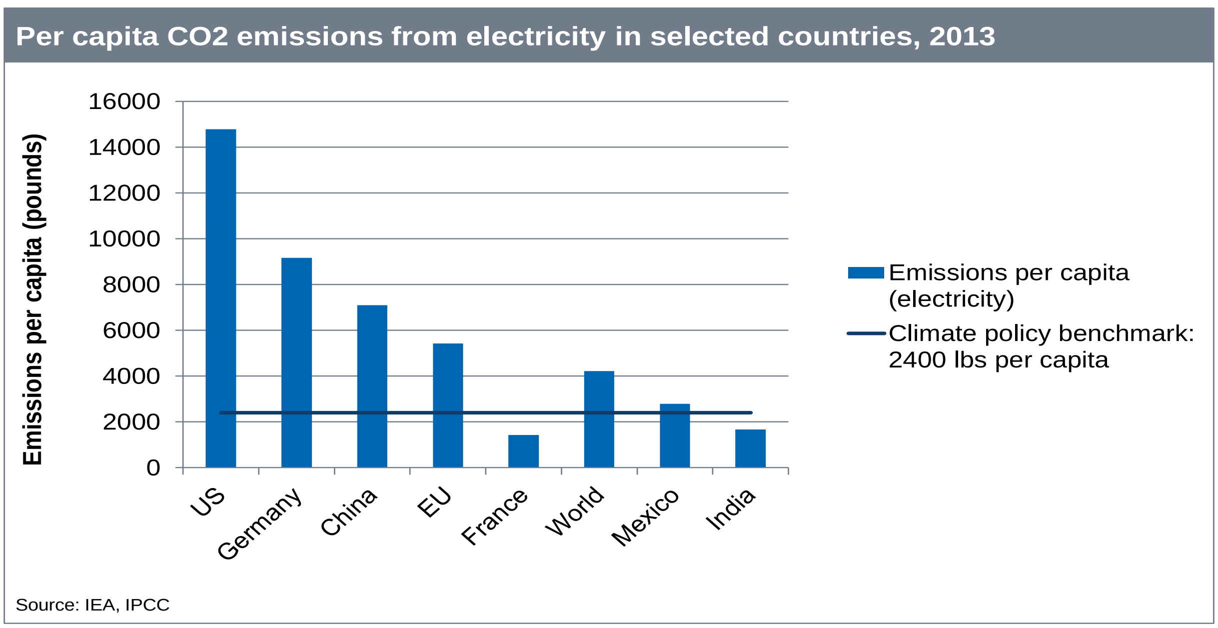
[25] International Energy Agency, *Global Tracking Framework*, 2013

Paris Climate Agreement implications for electric CO_2 emission footprints

If current trends continue, the electricity sector share of overall CO_2 emissions will continue to increase. Electric sector CO_2 emissions in developed economies like the US, account for over forty percent of annual anthropogenic CO_2 emissions. Looking ahead, further electrification ought to move the electricity share of a developed economy anthropogenic CO_2 emissions to 45 percent over the next 25 years. Approaching the 45 percent share of the overall 5,500 annual lbs. CO_2 emissions per capita target translates into an electricity carbon footprint climate policy target of around 2,400 annual lbs. CO_2 emissions per capita by 2040.

Figure 19 shows the per capita electricity CO_2 emissions for selected countries in relation to the annual 2,400 lbs. of CO_2 per capita electric climate policy target associated with the electricity sector doing its part to meet the climate policy challenge.

FIGURE 19

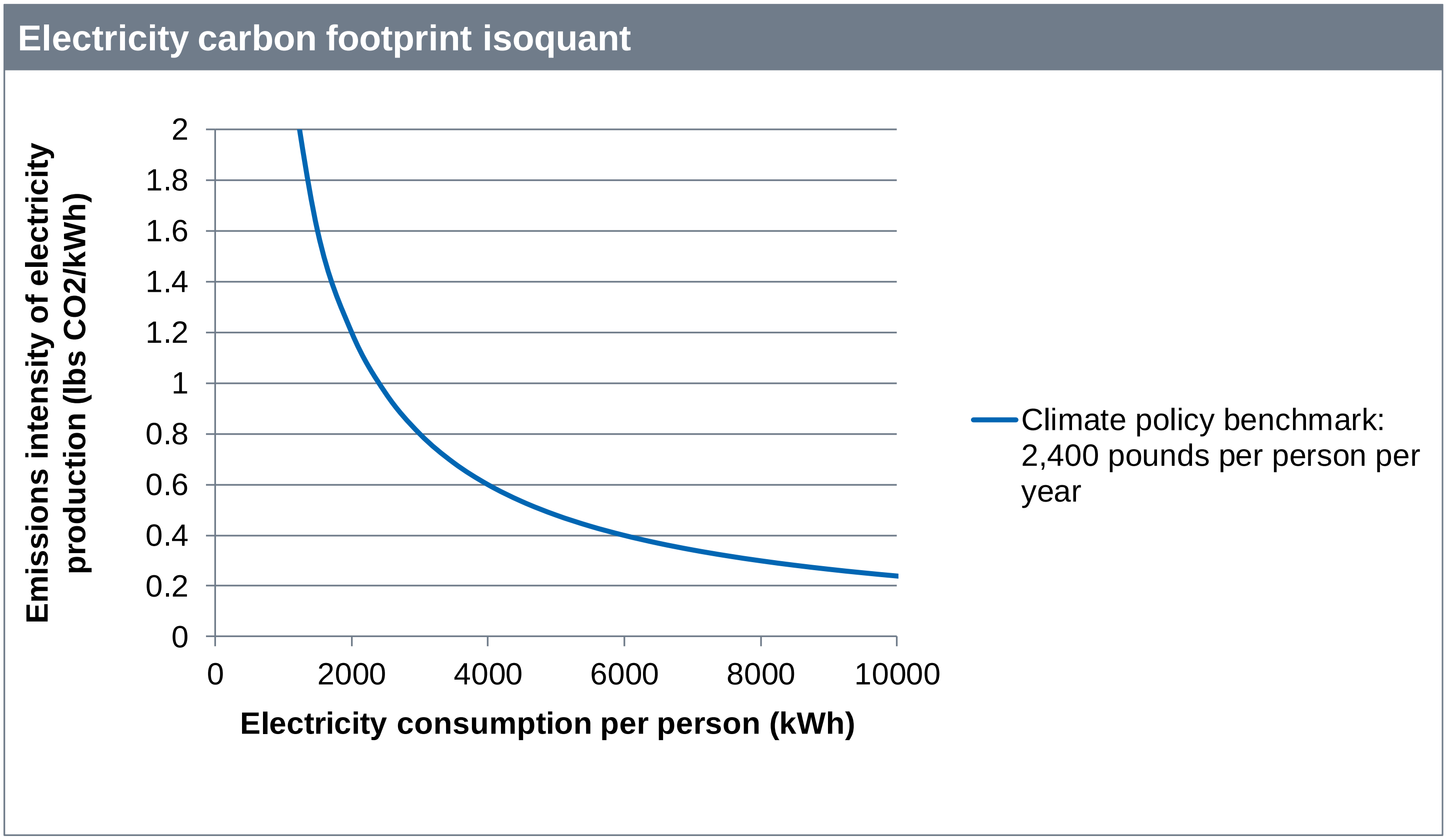


The gaps between national per capita electricity CO_2 emissions and policy benchmarks shown in Figure 19 reflect the linkages between economic development, electricity consumption and CO_2 emissions. Most developing economy lifestyles involve little or no gaps due, in large part, to significant levels of energy poverty. In contrast, developed economy life styles involve electricity CO_2 emissions that are more than climate policy benchmarks, with a few exceptions. The exceptions are developed countries with natural endowments of geothermal or hydro resources, or legacy programs involving nuclear power resources capable of supplying large shares of non-CO_2 emitting electricity into the generation mix.

Electricity sector CO_2 emission analysis framework

Per capita electric CO_2 emissions provide a CO_2 emission policy metric reflecting factors from both the consumption and production sides of the electricity sector. The factor on the consumption side is per capita electric consumption (annual KWh/capita). The factor on the supply side is the CO_2 intensity of electric energy production (lbs. CO_2 emissions/KWh). The product of these two factors is the electricity CO_2 emission footprint (annual lbs. CO_2 per capita). Figure 20 shows the combinations of demand and supply side factors that produce the same electric CO_2 emission of 2,400 annual lbs. CO_2 per capita.

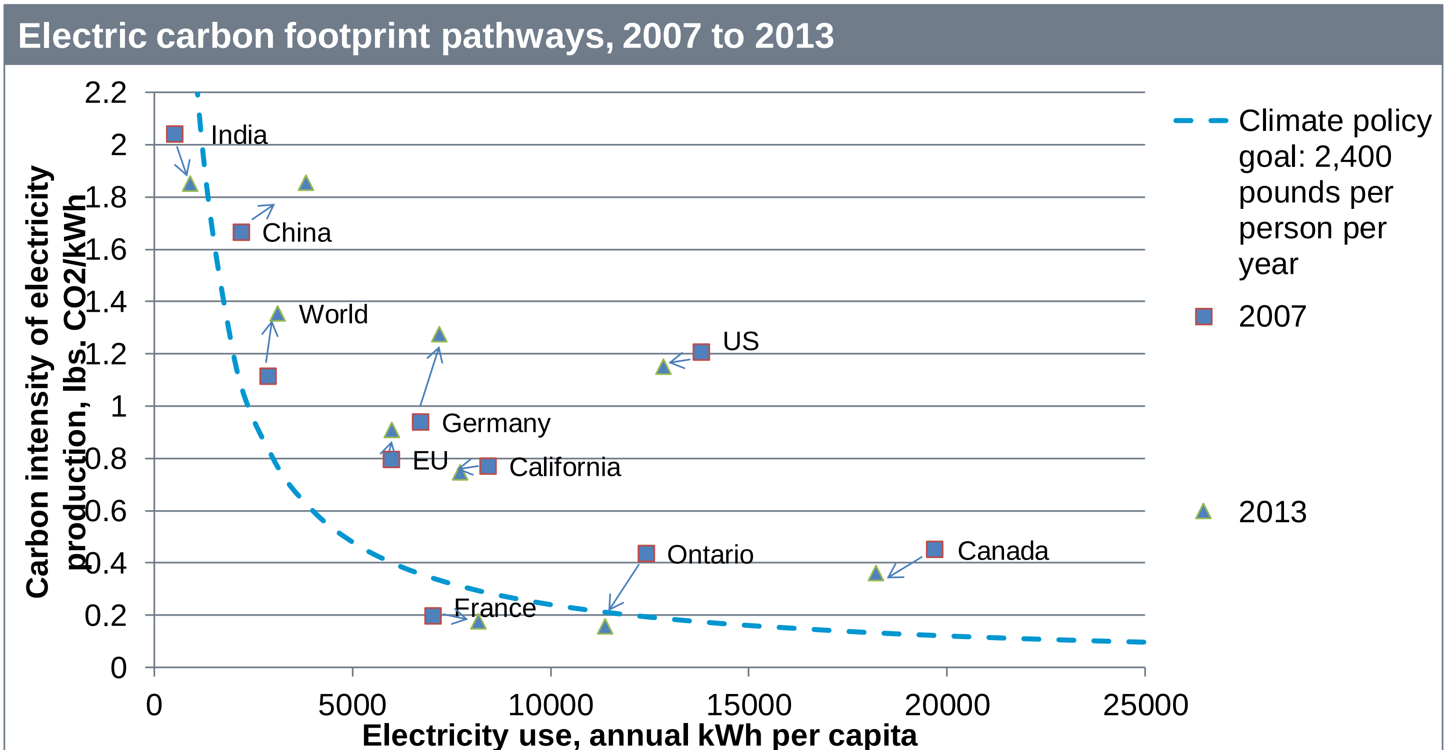
FIGURE 20



Assessing electric sector climate policy initiatives

The electric climate policy frontier of 2,400 annual lbs. CO_2 emissions per capita provides a metric to judge the track record of electricity sector climate policy initiatives. Figure 21 shows electricity CO_2 emission footprints for the world and selected national, provincial or state electricity sectors in relation to this climate policy benchmark.

FIGURE 21



Notes: 2400 lbs frontier is based on annual emissions of 26 Gt in a world with 9 billion people, where electricity represents 40% of emissions.
Source: IEA (carbon emissions), EIA (power generation), World Bank (population), IESO (Ontario)

The gaps between global average per capita electricity CO_2 emission and electric policy benchmark frontiers in Figure 21 measure the size of the electricity sector CO_2 emission policy challenge. Changes in these gaps across the 2007 to 2012 timeframe for selected countries, provinces and states indicate:

1. **The electric climate policy challenge is big**— closing the global gap between the CO_2 emission footprint and the 2,400 annual lbs. CO_2 per capita frontier by 2040 requires a greater than fifty percent reduction in global electricity CO_2 emissions.
2. **Global electricity sector climate policies are not meeting the climate policy challenge**--the gap between global average per capita CO_2 emissions and the 2,400 annual lbs. CO_2 per capita frontier is widening as time passes.
3. **Increasing global electricity CO_2 emissions footprints reflect reinforcing demand and supply side trends**—global increases in electricity use per capita continue to reinforce increases in the CO_2 intensity of electricity production.
4. **CO_2 emission leakage affects CO_2 emission comparisons**—some of the movement of industrializing economies such as China away from the frontier is due to leakage of emissions from other countries whose electric intensive industry shifted production overseas to industrializing nations such as China.
5. **The European Union in general, and particularly the German power sector policy initiatives, are not working**—although Germany is on the leading-edge of EU climate initiatives, both overall EU and German power sector CO_2 emissions are going up and expanding the gap between its per capita CO_2 emissions and the 2,400 annual lbs. CO_2 per capita frontier.
6. **India currently meets climate policy benchmarks but does not provide an example to follow—**India's per capita electric CO_2 emission is close to the 2,400 annual lbs. CO_2 per capita frontier because roughly over 300 million people of the

country's 1.25 billion people do not have access to electricity. Although effective, energy poverty is not a desirable solution to the global warming problem.

7. **California has not made much progress in demonstrating effective electric sector climate initiatives—**although California is often considered the leading-edge of US power sector climate initiatives, its electricity CO_2 emission footprint remains too high and has declined too slowly to provide an attractive example for other power systems to follow.
8. **France and Ontario achieve the 2,400 annual lbs. CO_2 emission per capita goal—** France and Ontario rely on nuclear generation for 77 and 62% of generation respectively and rely on rely on renewables, including hydro, integrated by fossil fueled-technologies for the remainder of electric supply.[26]

Electricity sector climate policy challenge

Meeting the global electricity climate policy challenge within the available window of opportunity requires two developments. First, a developed economy electricity system needs to demonstrate an attractive example of how to achieve an annual electric 2,400 lbs. CO_2 emissions per capita footprint while supporting modern electric intensive lifestyles. Second, social pressure needs to drive other power systems worldwide to follow the examples power system best practices.

Electricity systems around the world are not on track to do their part to equate anthropogenic CO_2 emission sources and sinks to stabilize atmospheric concentrations of CO_2 at or below 450-ppm within the next 25 years. Therefore, the global electricity sector is on track to fail to meet the climate policy challenge.

Getting the electricity sector on track to effective and efficient outcomes requires reframing climate policies based on lessons from policy shortcomings. California is on the leading-edge of US electric sector climate initiatives but California is failing to meet the electricity climate policy challenge. Looking ahead, the US can lead by example by incorporating the lessons from California's past electric climate policy shortcomings and alter course to move in the direction of following the least-cost pathway to lowering electricity CO_2 emission footprints to achieve climate policy targets at a politically acceptable cost.

[26] http://www.world-nuclear.org/info/facts-and-figures/nuclear-generation-by-country/

Chapter 3: California electric sector climate policy assessment and lessons

California electric climate policy shortcomings

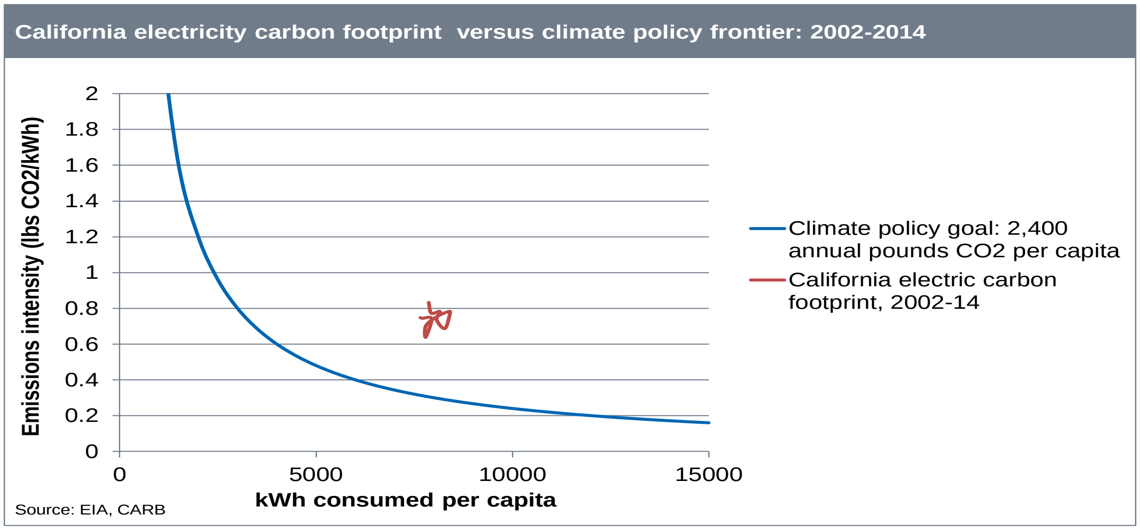
California is generally considered to be on the leading-edge of electric sector climate policy initiatives. But this perception rests on a distorted view of the facts on the ground. As a result, California electricity climate policy is viewed in a far more favorable light than is objectively justified.

This California electric climate policy assessment focuses on the track record since 2002 to evaluate the impact of the electric sector climate initiatives. California moved to the leading-edge of electric sector climate policy initiatives in 2002, when state legislation mandated the first renewable electric energy generation share targets and timetable. Since 2002, California's climate policy initiatives ratcheted up the renewable portfolio mandate four times, ultimately ratcheting up its renewable power portfolio mandate to 50 percent by 2030, carved out solar and distributed generation shares in the renewable mandate, set CO_2 emission limits for power supply resources, implemented a cap-and-trade program that included electric sector CO_2 emissions, increased renewable power subsidies, and doubled annual spending on rate-payer funded electric consumption efficiency programs.

Since California typically imports about one-third of its electricity supply, the carbon intensity of overall electricity supply reflects both in-state and out-of-state electric production CO_2 emission intensities. Since the physics governing power flows in an electric grid do not allow differentiation of the sources of imported electricity, the estimated CO_2 intensity of electric energy imports into California reflect the average CO_2 intensity of electric energy generated in the Western Interconnection outside of California.

Figure 22 shows the California electricity CO_2 emission footprint across the dozen years of policy implementation relative to the climate policy goal of an annual 2,400 lbs. CO_2 emissions per capita. Changes in California demand and supply-side factors are not closing the gap, at the required pace, to the 2,400 annual lbs. CO_2 emissions per capita climate policy goal. The California electricity CO_2 emission footprint declined 1.1 percent per year from 2002 to 2014 and this pace of change would have to triple across the next twenty-five years to close the 58 percent gap between the current electricity CO_2 emission footprint and 2,400 lbs. annual CO_2 emissions per capita climate policy goal.

FIGURE 22



The California's climate policy track record involves an electricity CO_2 emission footprint that remains too high. California's 2014 electric CO_2 emission footprint was around 5,724 lbs. annual CO_2 emissions per capita, and this level is 58 percent higher than the climate policy goal of 2,400 lbs. annual CO_2 emissions per capita. Annual global electric sector CO_2 emissions would be over one-third higher today if everyone in the world had an electricity CO_2 emission footprint equivalent to that of California.

California lagged, rather than led, the 1.8 average annual rate of decline in the US electric CO_2 emission footprint across the 2002 to 2014 interval.[27] Moving to lead rather than lag in the years ahead is unlikely because California's renewable power mandates are creating mounting problems for power system operators. Efforts to solve these problems involve diluting the power system impacts by expanding the scope of operations within the regional grid. Looking ahead, the success of this approach likely depends on Western states not following California's lead of mandating 50 percent renewable generation shares and creating similar operational challenges.

Changes in California in-state demand and supply factors did not produce any decline in the CO_2 emission footprint from 2002 to 2014. Although California more than doubled annual spending on rate payer-funded efficiency programs between 2002 and 2014, electrification trends caused California electric energy consumption per capita to increase by 3 percent. Since KWh per capita is one of the two electricity CO_2 emission footprint factors, this increase had a proportional impact on the electricity CO_2 emission footprint.

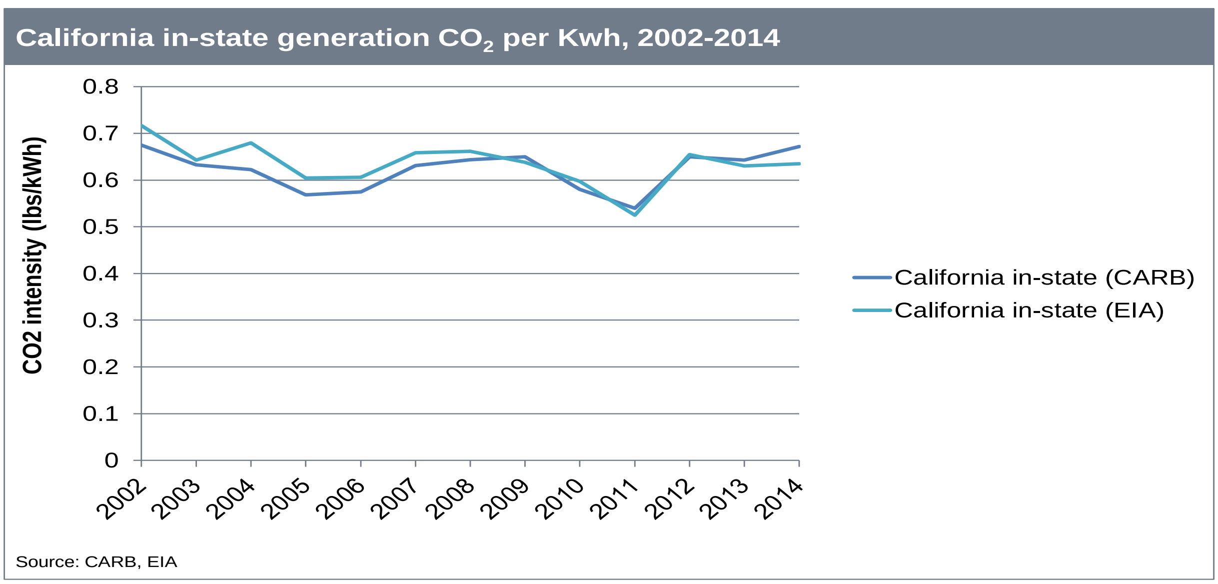
California in-state electric generation CO_2 emissions per Kwh declines were too small to lower the electricity CO_2 emission footprint. The CO_2 emission intensity of California in-state electric generation declined only 3 percent from 2002 to 2014. This decline did not have a proportional impact in the CO_2 emission footprint because in-state electric generation accounts for only two-thirds of power

[27] US Energy Information Administration

supply. Therefore, the 3 percent decline in the CO_2 emission intensity of in-state generation was more than offset by the 3 percent increase in overall electricity consumption when determining the in-state factor changes contribution to the overall change in the California electricity CO_2 emission footprint.

There is some uncertainty regarding the exact magnitude of the change in the California in-state generation CO_2 emission intensity because some differences exist in CO_2 emissions accounting treatments for biomass generation between the US EPA and the State of California Environmental Protection Agency Air Resources Board (CARB). However, as Figure 23 shows, these treatments account for small differences in the tracking of carbon intensity for California in-state generation.

FIGURE 23



There is certainty regarding why California in-state generation CO_2 emission intensity declined so little. First, the in-state renewable generation share—wind, hydro, geothermal, solar and biomass—remained relatively constant at 30 percent from 2002 to 2014 because the increase from 2 to 11 percent in the wind and solar in-state generation share was offset by declines in geothermal and hydroelectric in-state generation shares.[28] Second, the impact from the decline in the coal and oil-fired in-state generation share from 2 to 1 percent and the production efficiency gains generated by the replacement older natural gas-fired power plants with newer and more efficient natural gas-fired power plants were largely offset by the in-state generation share for natural gas-fired resources increasing from 50 to 60 percent due to the need to integrate intermittent renewables and replace the nuclear generation share that declined from 18 to 9 percent of in-state generation.

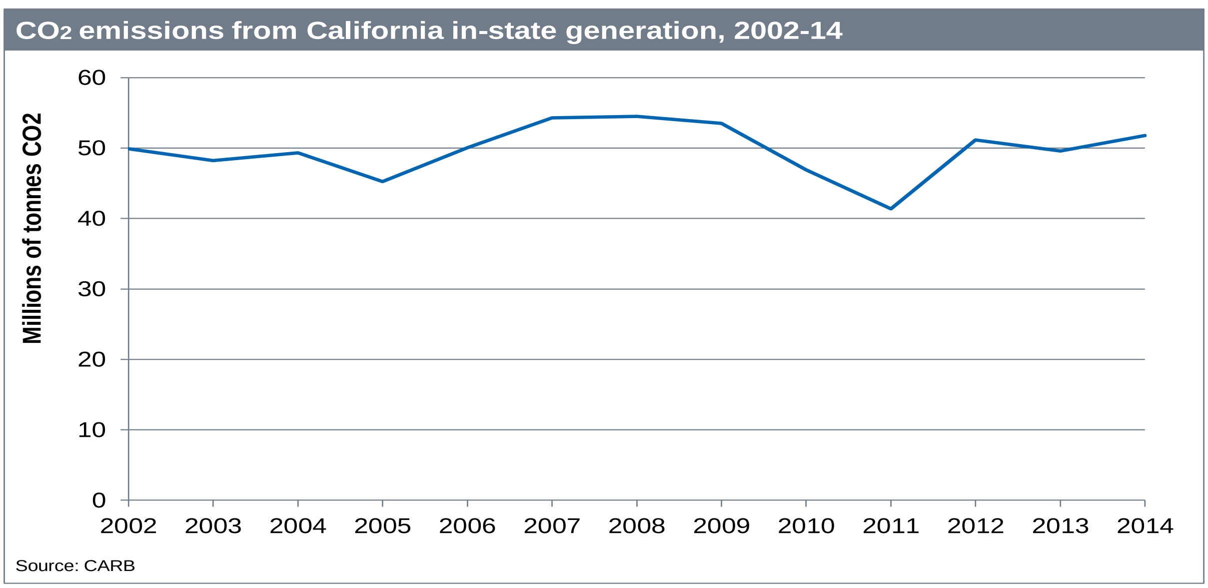
Looking ahead, further reductions in California's in-state electric generation CO_2 emission intensity involve more offsetting changes. California in-state hydroelectric generation in 2014 was almost 14 TWh below the most recent 15-year average and a recovery from

[28] California Energy Commission, Energy Almanac, http://energyalmanac.ca.gov/electricity/electric generation capacity.html

these recent drought conditions will exert downward pressure on the CO_2 emission intensity of existing in-state generation. However, the hydro recovery impact will be more than offset when the Diablo Canyon nuclear power plant closes and eliminates over 18 TWh of zero CO_2 emission nuclear generation in the years 2025 and beyond.

A solution to the global warming problem requires reducing the absolute level of CO_2 emissions. The absolute level of California electric generation CO_2 emissions did not decline from 2002 to 2014. Therefore, California did not contribute to the 10 percent decline in US electric sector CO_2 emissions across the past dozen years.[29] Although California generated a slightly lower share of its overall electric supply in 2014 versus 2002, nevertheless, the 7 percent increase in California in-state electric generation exceeded the 3 percent decline in CO_2 emissions per KWh of in-state generation and caused, as Figure 24 shows, CO_2 emissions from in-state generation to remain around 50 million metric tons.[30]

FIGURE 24

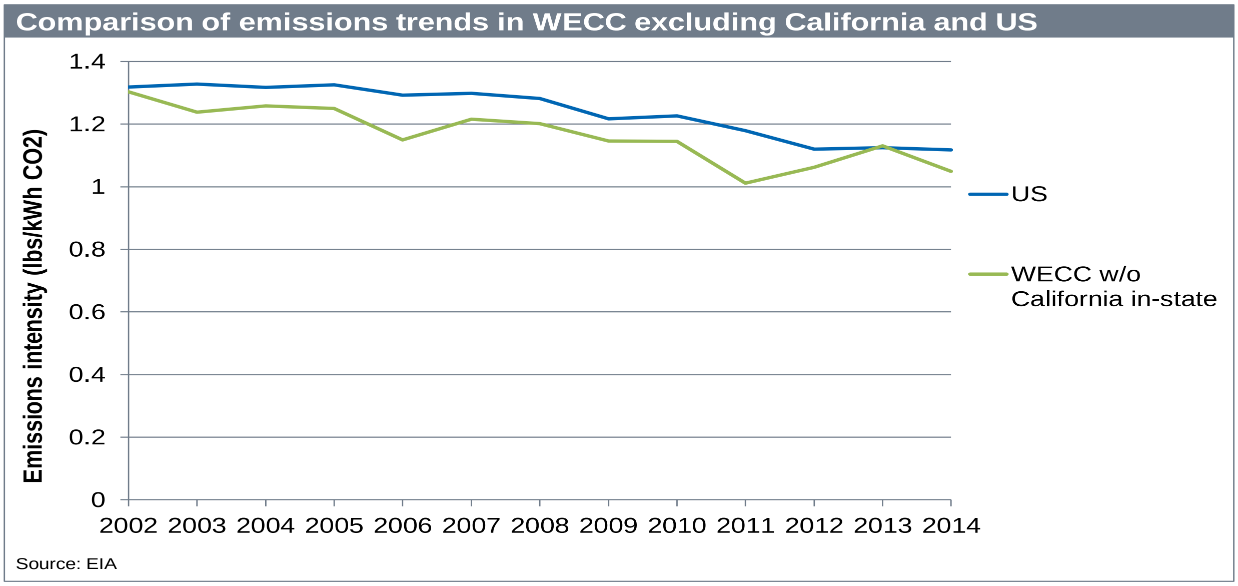


The decline in the California electricity CO_2 emission footprint from 2002 to 2014 was due entirely to the decline in the CO_2 emission intensity of imported electricity produced outside of the regulatory jurisdiction of California. The impact of California climate policy initiatives remains unclear because the track record does not provide evidence linking California policy initiatives to declines in the CO_2 emission intensity of electricity imported into California.

[29] US Environmental Protection Agency, *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2014*, 2016.
[30] California Environmental Protection Agency, Air Resources Board, *California Greenhouse Gas Inventory—2016 edition*, June 17, 2016.

The CO_2 emissions intensity associated with electric energy generated in the Western Interconnection (WECC) outside of California declined 19.5 percent, from 1.30 to 1.05 lbs. CO_2 per KWh from 2002 to 2014. As Figure 25 shows, this 1.8 percent annual rate of decline was above the US industry average rate of decline of 1.4 percent per year from 2002 to 2014.

FIGURE 25



Several factors, outside of climate policy initiatives, drove the decline in the CO_2 emission intensity in both the US and the Western Interconnection. The primary factor was the impact of the rapid expansion of shale natural gas production. This innovation in natural gas supply altered relative fuel prices significantly and caused power system economic dispatch to substitute natural gas-fired generation for coal-fired generation. Since the CO_2 emission intensity of natural gas-fired generation is roughly half that of coal-fired generation, this shift in generation fuel mix drove the average CO_2 emission intensity of electric production down. In addition, the average age of coal-fired power plants is above 40 years and significantly exceeds the average age of natural gas-fired generating plants, contributing to coal-fired power plant retirements outpacing natural gas-fired retirements across the past dozen years. Meanwhile, natural gas-fired generation technologies dominated the mix of new capacity additions and thus, this long-run technology turnover increased the natural gas share of capacity and reinforced the short-run fuel substitution impact of natural gas for coal-fired generation on the CO_2 emission intensity of electric production.

The contribution of California climate policy initiatives to the decline in the CO_2 emission intensity of electricity imported from the Western Interconnection is unclear. This lack of situational awareness results from the California Air Resources Board CO_2 emission accounting treatments that shuffle the resources attributed as sources of electricity exported to California without reconciling these power flow assignments to actual grid power flows determined by the underlying physics.

California's climate policy track record does not provide an example of appropriate policy adjustments in response to accumulating evidence of ineffective and inefficient outcomes. Instead, the track record shows California responded to policy shortcomings by doubling down on the existing policy approaches. This lack of adjustment is forcing the power system operator to address mounting problems by expanding the scope of operations to dilute the impacts of the California policies across a broader scope of power system operations and planning.

California's electric sector climate policy track record provides lessons for climate policy formulation and implementation, including:

1. **Political policy distortions—**the political process tends to translate the pressure to do more about global warming into optimistic, appealing but unrealistic climate policy formulations.
2. **Technology constraints—**climate policy underperformance results from underestimating the constraints imposed by the underlying physics and technology of power systems.
3. **Inappropriate metric selection—**the optimistic bias in policy formulations leads to the selection of policy targets and evaluation criteria that are prone to overstating policy performance and obfuscating policy shortcomings.
4. **Consumption efficiency trade-offs**—rate payer-funded programs to increase electric energy consumption efficiency involve positive and increasing economic costs.
5. **Time integrated production costs—**flawed time ignorant cost assessments of wind and solar generation versus dispatchable electric supply technologies cause overestimates of substitution possibilities and underestimates of the cost to expand renewable generation shares in an electricity supply portfolio.
6. **Economic inefficiency—**uncoordinated piecemeal climate policy approaches make reducing electric sector CO_2 emission more expensive than necessary.
7. **Regressive cost burdens—**inefficient and ineffective electric sector climate policies increase electricity prices and distribute the associated cost burden disproportionally to lower income households.

Lesson 1: The political process tends to embed optimistic bias that distorts policy formulation.

The California electric climate policy track record indicates that significantly reducing the electricity CO_2 emission footprint is difficult and costly and that over a decade of initiatives have proven to be ineffective. Yet, California's governor Edmund Brown remains optimistic that the state's climate policy track record and current initiatives provide an example for other power systems to follow. At the American Geophysical Union Annual Meeting in San Francisco on December 14, 2016, Governor Brown conveyed his optimistic assessment of California climate policy when he noted:

> *"We will set the stage. We'll set the example, and whatever Washington thinks they are doing, California is the future."*[31]

Although optimism is often considered a leadership virtue, optimism is a misperception of reality. As a result, optimistic policy approaches have a lower probability of success than realistic approaches. The California policy track record is difficult to understand

[31] Transcribed at http://www.sacbee.com/news/politics-government/capitol-alert/article120928688.html, video available from the governor's office at https://www.gov.ca.gov/news.php?id=19629

without accepting the hypothesis that persistent electric sector policy shortcomings are a predictable outcome of a political process prone to formulating optimistic policy approaches. Eight building blocks create the logical foundation for a hypothesis that the political process is prone to embed a persistent optimistic bias into climate policy formulation that increases the probability of policy shortcomings. The eight building blocks are:

1. Politicians want to maximize political support by responding to public concerns.
2. Focus groups indicate that people are afraid of global warming and feel guilty about their electric intensive modern life styles.
3. Politicians see opportunities to motivate voters by responding to climate concerns. To do this, politicians must choose between telling voters that doing something about climate change is going to be complex and expensive (realistically involves making economic trade-offs) or simple and costless (involves unrealistic but appealing transformational visions).
4. Political competition in the election process creates demand for a plausible narrative supporting the more appealing, optimistic vision of electric sector transformation.
5. The complexity of climate policy creates the opportunity for influential and credible third parties to respond to the demand for a plausible optimistic narrative with studies indicating pathways exist to large GHG emission reductions at little or no cost that create jobs, accelerate economic growth and lower consumer monthly electricity bills.
6. Polling indicates voters will cast their ballots to reward optimistic climate policy visions and rival politicians respond by competing to propose optimistic policy proposals that stretch, but do not exceed, the limits of credibility.
7. Candidates that win political office follow through on optimistic climate policy campaign promises and focus on climate policy formulations that have a low probability of successful implementation. As part of this process, climate policy metrics are selected to set goals and evaluate progress that will not expose the predictable policy shortcomings.
8. Focusing on the metrics embedded into climate policies creates a lack of situational awareness and the lack of transparency preserves the momentum of optimistic policy initiatives despite available accumulating evidence of expensive, ineffective and inefficient policy outcomes.

Gaps between optimistic political rhetoric and reality are not new to California. California policy initiatives to support renewable electric generation began as a response to the 1973 OPEC oil embargo. At that time, California relied on oil for one-third of the primary energy inputs to fuel its electric generation.[32] California's political process responded to the energy crisis by formulating policies designed to encourage the development of a cluster of industries that would make California the world leader in the transition to the appealing, but unrealistic, goal of achieving energy independence.

Although energy independence was unrealistic, the California political process generated the Warren-Alquist Act in 1974 that established the California Energy Commission (CEC) with the intent to encourage, develop, and coordinate research and development into energy supply and demand problems.[33]

The CEC encouraged research and development efforts to deploy new technologies to accumulate experience, move up a learning curve and generate cost reductions during the 1980s to enable a transition to renewable energy. California also moved forward with policies designed to reduce dependence on fossil fuels by expanding nuclear power generation in the state's electricity supply

[32] US Department of Energy, Energy Information Administration

[33] California Energy Commission, *Strategic Plan*, http://www.energy.ca.gov/commission/documents/2014-06_California_Energy_Commission_Strategic_Plan.pdf

portfolio. California added units 2 and 3 to the San Onofre nuclear power station in 1983 and 1984 respectively, and added the Diablo Canyon nuclear units in 1985 and 1986.

In 1991, California renewable policy support expanded beyond research and development efforts when the California legislature amended the Public Utility Code to direct the Public Utility Commission to reserve or set aside a specific portion of California's future electrical generating capacity needs for renewable resources.[34] In addition, California began subsidizing distributed solar PV with the introduction of net metering at full retail prices. This program allowed a consumer with a solar PV installation of one MW or less to receive the retail power price, rather than the wholesale power price, as compensation for electricity delivered to the grid.

Net metering at full retail prices is a subsidy to distributed rooftop PV investments. Net metering at retail rates for rooftop solar power production charges a consumer for power taken from the grid at the retail electricity rate when the household rooftop PV output is below household needs at any point in time. Conversely, net metering at retail rates credits the household for any excess solar electricity produced when PV output exceeds the energy consumption of the household at any point in time. In this case, the grid acts as a battery—taking surplus power from the household when PV output is too high and returning power when the PV output is too low. Rooftop PV needs a battery because the pattern of solar power output does not typically align with consumer electricity needs. A recent study by the U.S. Department of Energy's National Renewable Energy Laboratory finds that about 65% of a typical rooftop solar energy customer's electricity demand is non-coincidental with the electricity generated from their own rooftop PV units.[35]

Net metering at retail rates makes it possible to have a "net zero" electric home when the kilowatt-hours produced over a month by the rooftop PV panel equals the kilowatt-hour consumption of the home for the entire month. A net zero home with net metering at full retail prices ends up with a monthly power bill of zero. Under this construct, the power grid acts as a battery to the PV installation and the battery service comes at no charge to a "net zero" consumer. However, if all consumers became net zero prosumers (producers and consumers) then nobody would pay for the metering, distribution, transmission, and generating systems needed for the grid to act as a battery. In California, these non-fuel costs currently account for 13 cents per kWh of the overall 15.5 cents per kWh average residential price of electricity in California. As a result, net metering at full retail prices provides a subsidy to PV households because net metering at the full retail price ends up distributing the cost burden of providing distributed generation battery services to those customers without distributed PV on their rooftops.

California energy independence policy initiatives proved expensive. In the mid-1990s, California retail electricity prices were over fifty percent higher than the US average. To ease the impacts on electricity bills, the California legislature shifted some of the cost burden to tax bills by passing Assembly Bill 1890 in 1996. This legislation increased support for renewable power development by creating the Renewable Energy Fund to provide $540 million in subsidies and incentives.[36]

The political pressure to do more to lower retail electric prices drove the California political process to restructure the electric sector in the mid-1990s based upon the optimistic vision that the political process of stakeholder compromise and negotiation could lower

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[34] Kevin S. Golden, Senate Bill 1078: *The Renewable Portfolio Standard-California Asserts Its Renewable Energy Leadership*, Ecology Law Review, Volume 30, Issue 3, June 2003.

[35] Bird, Lori, Carolyn Davidson, Joyce McLaren, and John Miller. *Impact of Rate Design Alternatives on Residential Solar Customer Bills: Increased Fixed Charges, Minimum Bills and Demand-Based Rates,* National Renewable Energy Laboratory, U.S. Department of Energy, September 2015. http://www.nrel.gov/docs/fy15osti/64850.pdf.

[36] Ibid.

electricity prices by properly formulating a move to rely more on market forces and less on regulatory processes. However, the California political process of stakeholder compromise and negotiation generated an optimistic, but unrealistic electricity market design that made a supply shortage inevitable.[37] A shortage materialized in 2000-01 and opened the door for power traders to exploit market conditions and turn the market shortage into a multi-year political crisis.

The California electricity crisis of 2000-01 blindsided the newly elected Governor Grey Davis and a series of optimistic but ineffective policy responses to the electricity crisis created increasing political dissatisfaction with the new Governor. To counteract these trends, the Governor recognized that concerns about climate change were moving up on the political agenda and California had a relatively favorable electricity sector CO_2 emission profile. At that time, solar, wind, biomass and geothermal electric generation accounted for 13 percent of California in-state electric energy supply and nuclear electric generation accounted for 16 percent of in-state electric energy production.[38] These non-CO_2 emitting sources of electric energy added to California's natural endowments of hydroelectric resources and produced a carbon intensity of electric energy supply (including imports) was 30 percent below the 2002 national average. On the demand side, relatively temperate climate conditions in California population centers produced relatively less demand for heating, ventilation and air conditioning. Consequently, California electricity consumption per residential customer was 40 percent lower than the US average in 2002. Adding the remaining commercial and industrial electric consumption into the per capita metric produced an electric energy consumption per capita level in California that was 35 percent below the national average in 2002. The net result of these demand and supply-side factors was an electricity CO_2 emission footprint 63 percent lower than the US average in 2002.

Governor Davis pursued the opportunity to shift the focus away from California trying to be a leader in electric deregulation policy and toward California trying to be a leader in electric sector climate policy. Governor Davis found political traction with the idea that a transition to power system relying more on wind and solar resources could lower GHG emissions while generating benefits rather than costs. Governor Davis provided this optimistic, appealing but unrealistic climate policy vision on August 19, 2002 when he announced:

> California is the nation's leader in renewable energy – and we intend to keep that title. The benefits of using renewable energy include the reduction of electricity market volatility by cutting California's reliance on natural gas; retiring old fossil-fuel fired plants that are particularly dirty and inefficient; reduced pollution and greenhouse gas emissions; and a net benefit to the state's economy worth billions of dollars due to job creation and more energy expenditures remaining in California – instead of going elsewhere." [39]

In 2002, the California legislature passed Senate Bill 1078 establishing the first state mandate and timetable for a renewable electric energy generation share. The renewable portfolio standard required entities serving electric loads in California to provide 20% of

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[37] Lawrence Makovich testimony to the United States Senate Committee on Energy and Natural Resources, Committee Chairman: Frank H. Murkowski, Senator from Alaska, "California's Electricity Crisis and Implications for the West" January 31, 2001 – Washington, DC, and United States House of Representatives Committee on Energy and Commerce Subcommittee on Energy and Air Quality Committee Chairman: Joe Barton, Representative from Texas "Electricity Markets: California" March 22, 2001 – Washington, DC

[38] California Energy Commission, *Energy Almanac*, http://energyalmamac.ca.gov/electricity/electricity_generation.html

[39] http://www.gray-davis.com/ViewLibraryItem.aspx?ID=8272

electric supply from qualified renewable electric energy sources (large hydro resources did not qualify as renewable resources) by 2017.[40]

Democratic Governor Grey Davis signed SB 1078 into law before the political backlash from the California power crisis led to his recall in 2003. But the optimistic vision of an electric sector transformation generating economic benefits rather than economic costs did not lose momentum with his Republican successor, Arnold Schwarzenegger who advanced the Million Solar Roof initiative on August 20, 2004 with his own version of an optimistic climate policy proposition:

> This proposal is about smart, innovative and environmentally friendly technologies that will help improve the state's ability to meet peak electricity demand while cutting energy costs for homeowners for years to come. Once implemented, it will establish California as a world leader in solar technology.[41]

Political pressure to do more to address climate continued to increase in the early 2000s. The California legislature responded by passing Assembly bill 32 and Senate Bill 107--the Global Warming Solutions Act of 2006--that empowered the California Air Resources Board to implement climate initiatives to achieve a 30 percent reduction in California's CO_2 emissions from 1990 levels by 2020. The Global Warming Solutions Act accelerated the 20 percent renewable generation share mandate by moving the compliance date up to 2010. In addition, AB 32 established a cap-and-trade program that included the electric sector beginning in 2013. Legislation in 2006 also included Senate Bill 1368 that set CO_2 emission performance standards (1,100 lbs. CO_2 emissions per MWH) for the power supply procured by California load serving entities.

California ratcheted up the renewable target to 33 percent for 2020 when Governor Arnold Schwarzenegger signed Executive Order S-14-08 on November 17, 2008. The California legislature expanded support of this initiative in 2008 with the passage of Assembly Bill 811 that increased state subsidies for distributed generation and electric consumption efficiency improvements.

California electric policy initiatives failed to meet policy goals. Grid infrastructure and power supply development efforts did not close the gap between the starting point of about 11 percent qualified renewable generation in 2006, and the 20 percent qualified renewable generation goal by 2010. The shortfall reflected the optimistic underestimation of the power system integration challenges of renewable power resources. This shortfall reflected a policy formulation blind spot created by mandating renewable generation share policy targets before conducting a power system renewable integration study. The California legislature responded to the apparent obstacles by passing Assemble Bill 2514 that initiated mandates for some electric storage systems to facilitate renewable power integration.

Governor Jerry Brown took office in 2011 and responded to the failure to meet the previous year climate policy goals by signing Senate Bill X1-2. This initiative doubled down on the existing policy approach by ratcheting up the renewable generation share goal to 33% by 2020. This policy reset also added interim targets requiring 20 and 25 percent renewable shares by the end of 2013 and 2016 respectively. The California Public Utility Commission facilitated the initiative by adding regulations in 2013 requiring that in-state utilities together develop 1,325 MW of energy storage capability by 2030.

Focusing on policy metrics such as the growth in wind and solar generation generated optimism that more aggressive climate policy goals were achievable. Consequently, Governor Brown issued an executive order in April 2015 to reduce California GHG emissions 40

[40] California Energy Commission, *Tracking Progress*, December 22, 2016.

[41] http://www.energy.ca.gov/releases/2004_releases/2004-08-20_governor_solar.html

% below 1990 levels by 2030 and 80% below by 2050. Part of the Governor's vision involved increasing electric vehicles registrations in California from 250,000 to 1.5 million by 2025 (1.5 million EVs creates an increase of roughly 5 percent in electric energy demand by 2025). To move the Governors vision forward in the electricity sector, Senators Kevin de León and Senator Mark Leno formulated Senate Bill 350 based on an optimistic assessment that costless CO_2 emission reduction options were available on both the demand and supply sides of the California electricity sector.

On the demand side, the authors of SB 350 asserted that increases in electric energy consumption efficiency would more than pay for themselves by generating savings rather than costs when they noted:

> State energy agencies allocate over $1.5 billion per year on energy efficiency programs. Roughly $1 billion is spent by the California Public Utilities Commission (CPUC) and utilities via utility-sponsored programs such as rebates for high-efficiency appliances, heating and A/C systems, and insulation.
>
> And
>
> Energy efficient buildings save money and reduce pollution from electricity. According to the California Energy Commission, efficiency standards return an average of $6,200 in energy ***savings*** (emphasis added) per household over 30 years, or $27 per month on heating, cooling, and lighting bills.[42]

On the supply-side, the authors of SB 350 asserted that the substitution of wind and solar power for conventional electric generating technologies would reduce GHG emissions at no additional cost because of the perceived cost parity of wind and solar technologies versus conventional electric generating technologies. The authors observed:

> Renewable energy is ***as cost-effective as fossil fuels*** and produces much less pollution. According to the International Renewable Energy Agency, renewable power generation costs in 2014 were either ***as cheap as or cheaper than coal, oil, and gas-fired power plants—even without financial support and despite drops in oil prices*** (emphasis added)***.*** Solar-powered energy has had the largest cost decline, with solar PV (rooftop solar) being 75% less expensive than it was in 2009.[43]

The authors of SB 350 choose to rely on the IREA generating cost comparisons that employed simple levelized cost of energy comparisons that did not incorporate the time dimension of electric supply relative to aggregate consumer demand, despite the well-documented significant integration costs associated with the mismatch between renewable resource output patterns and consumer consumption patterns identified by the California ISO renewable integration study produced over seven years before.[44]

Governor Brown signed SB 350—The Clean Energy and Pollution Reduction Act of 2015--into law in December of 2015 and thereby increased the renewable generation requirement for California retail electric suppliers to 50% by 2030, including a carve out for distributed generation.

The lesson is that the California electric sector policy track record indicates that climate policy formulations remain optimistic despite accumulating evidence that current approaches are proving expensive and ineffective. It is difficult to accept the hypothesis

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[42] Ibid.
[43] http://focus.senate.ca.gov/sites/focus.senate.ca.gov/files/climate/505050.html
[44] California ISO., *Integration of Renewable Resources: Transmission and Operating Issues and Recommendations for Integrating Renewable Resources on the ISO-Controlled Grid*, November 2007. http://www.caiso.com/1ca5/1ca5a7a026270.pdf.

that the persistence of optimistic climate policy approaches simply reflects a lack of understanding of the facts on the ground. The implication is that the track record of California electric sector climate policy initiatives does not allow rejection of the hypothesis that the California policy shortcomings are a result of an optimistic bias in the political process of climate policy formulation and evaluation.

Lesson 2: Climate policy underperformance results from underestimating constraints imposed by the underlying physics and technology of power systems.

Physics and technology shaped the 135-year evolution of US power systems to reach the current state of technology. The state of technology defines what is possible and therefore, aligning climate policy approaches to the capabilities of power system technology is a necessary condition for setting and achieving realistic policy objectives.

California introduced simple climate policies at odds with the complex technology and the underlying physics of power systems. Two key policy shortcomings arose from these misalignments:

1. California CO_2 emission accounting treatments failed to accurately reflect changes in the CO_2 emissions associated with the one-third of power supply imported into the state from the rest of the Western Interconnection. Misalignments arose because grid technology defines the geographic scope for the regional power systems of the Western Interconnection that are much broader than the political boundary that defines California's climate policy jurisdiction and physics dictated power flows throughout the grid and thereby hindered "tagging" the sources of California electricity imports. As a result, California's unilateral climate policy initiatives and the lack of regional climate policy coordination created a lack of transparency regarding what, if any, changes resulted in regional electricity flows and the associated changes in the imported electricity CO_2 emission intensity.
2. The size and pace of renewable power mandates caused ramping and over-generation problems that hindered achievement of policy targets. California mandated renewable power generation shares before conducting power system integration studies to understand the impact of these intermittent resources on the security constrained economic dispatch of the regional power system.

Power system technology requires the physical connection between consumers and producers. As a result, a power system is defined by geographic extent of the grid providing a high degree of integration between electric consumers and producers. Consequently, the California political boundary does not align with the bounds of the broader Western Interconnection power system connecting California consumers to electric suppliers.

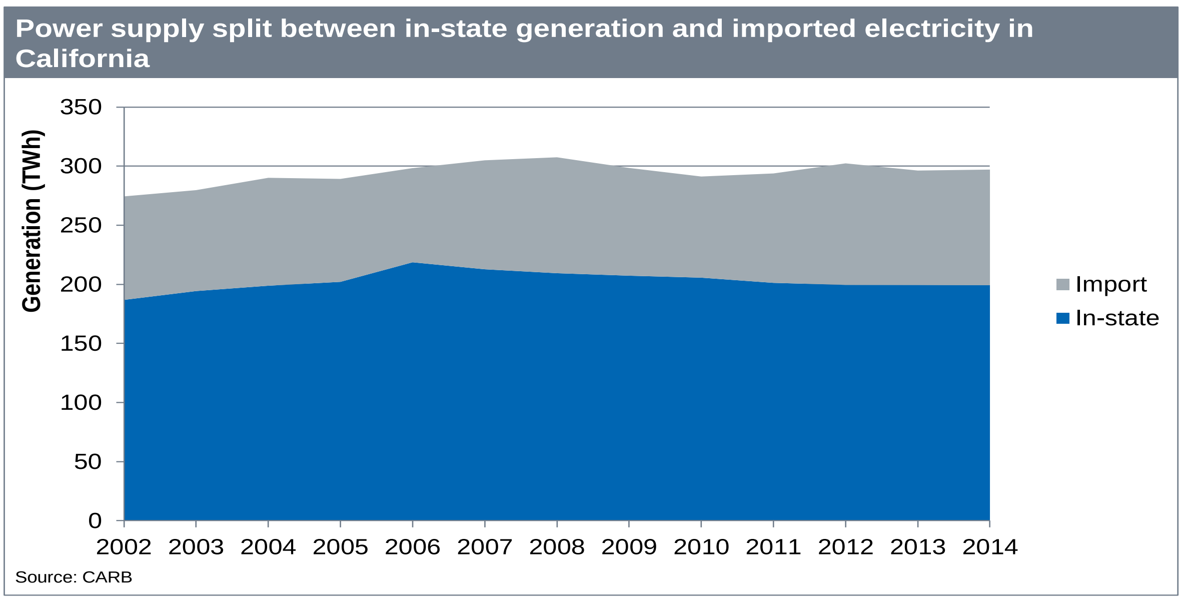
The Western Interconnection is one of handful of major electric systems in the US and Canada. The Western interconnection spans more than 1.8 million square miles in all or part of 14 states, including California as well as the Canadian provinces of British Columbia and Alberta, and the northern portion of Baja California in Mexico.[45] California's electricity consumption accounts for about one-fifth of the electric consumption in the Western Interconnection. The interconnection organization enforces reliability

[45] Western Interconnection, *2015 State of the Interconnection*

standards for generation and delivery through the coordinated, but decentralized, operation of 38 electric system balancing authorities, seven of which cover different parts of California.[46]

California's integration into the Western Interconnection is not new. As Figure 26 shows, the high degree of interconnection of California into the broader regional power system enabled the state to traditionally meet about one-third of its electricity demand with imported electricity.[47] Consequently, when California formulated unilateral climate policy initiatives, these initial conditions limited the ability to affect the CO_2 emission intensity of the state's overall electricity supply.

FIGURE 26



California's high degree of integration into the Western Interconnection creates a state policy dilemma. California wants to regulate the CO_2 emission content of its electric consumption but this is not a well-defined idea. Instead, meaningful CO_2 emission measures are in the context of grid integrated electric production. As a result, California's inability to constrain CO_2 emissions from all sources of electric production produces a large gap between the rhetoric of its regulation of electric consumption embedded CO_2 emissions and reality.

46 https://www.wecc.biz/Administrative/WECC

47 California Energy Commission. *Total Electricity System Power: 2014*. Data as of September 10, 2015. http://energyalmanac.ca.gov/electricity/total_system_power.html.

California tried to regulate the CO_2 emission intensity of imported electricity with regulations put in place in 2006. These regulations imposed an emission performance standard of 1,100 lbs. CO_2 emissions per MWh on the in-state load serving entities acquiring electric energy supply from both inside and outside of the state.

The California Environmental Protection Agency Air Resources Board (CARB) tracks compliance with the emission performance standard using an accounting framework that assigns CO_2 emissions to California's imported electric energy based on specified power supply affiliations. This CARB tracking mechanism attributes CO_2 emission changes to affiliation changes that include ownership changes, altered electricity contract pathways and power plant closures.

The CARB CO_2 emissions accounting treatments make the impacts of the California emission performance standards on the CO_2 emissions of imports from the rest of the Western Interconnection unclear and arbitrary. The compliance mechanisms associated with California's emission performance standards do not align with actual electricity flows determined by the physics underlying Western Interconnection power system technologies. This misalignment obfuscates the impact of California electric sector climate policies on CO_2 emissions associated with electricity imports.

CARB CO_2 accounting treatments do not align with changes in actual electricity flows when compliance actions involve power plant ownership changes or alterations to electricity contract pathways. For example, CARB CO_2 emission accounting treatments drove Southern California Edison to sell their combined 720 MW ownership stake in units 4 and 5 of the Four Corners coal-fired power plant (located in New Mexico) to Arizona Public Service in 2013. Similarly, CARB CO_2 emission accounting treatments drove San Diego Gas and Electric (the contracted buyer of a 19 percent share of the generation from the Boardman coal-fired power plant located in Oregon) to comply with emission performance standards by not renewing the expiring power purchase contract with Portland General Electric (Boardman power plant owner and contracted seller). Although CARB assigned emission reduction credits from these actions, it is not clear that these actions had any impact on the CO_2 emission intensity of actual electricity flows in the West.

Ownership changes and altered contract terms did not, as Table 2 shows, result in dissimilar utilization rates of the power plants in the years before and after the affiliation changes. In addition, the affiliation changes did not alter the physics and economics determining actual electricity flows from these resources to consumers, including California consumers.

TABLE 2

Performance of generating units before and after California affiliation change		
Generating unit	**Capacity factor before termination**	**Capacity factor after termination**
Four Corners unit 4	75.8%	75.3%
Four Corners unit 5	75.1%	64.7%
Boardman unit 1	58.3%	54.5%
Source: SNL Financial		

The underlying physics governing electric flows in a power system involve Ohms law that dictates electric energy will flow between sources (generating plants) and sinks (consumer end uses) across all available pathways in the inverse proportion to the impedance of the conductors. See Impedance Box.

The Western Interconnection provides multiple, and in part overlapping, electrical pathways to conduct electricity from each source to each sink. Consequently, the electricity produced by power plants in the Western Interconnection will follow multiple pathways to California consumers based on the impedance of conductors within the grid pathways.

The current state of power system technology involves another layer of complexity to power flows because of the integration of some DC technologies into AC grids. For example, photovoltaic panels (PV) technologies produce DC electricity and since DC electricity does not involve sinusoidal waveforms for voltage and current, integration into the AC power system requires the use of inversion technologies to transform the DC electric energy into synchronous AC power supply. The current state of power system technologies also allows the conversion of AC electricity to DC electricity and these transformations enable the use of high voltage DC transmission line technologies to transmit electric energy between specific points within an AC grid. Of course, the DC electric energy requires inversion back to synchronous AC electric energy at the DC transmission line delivery point.

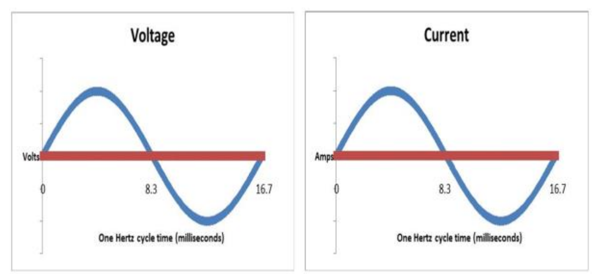
The complexity of the physics, technology and operations of the Western Interconnection means that as the degree of integration of any state into the broader regional power system increases, the degree of accuracy to differentiate the origins of electric energy crossing the state boundaries decreases. The bottom line is that California is so highly integrated into the complex physics and operations of the Western Interconnection that it is neither possible to track the specific origins of electric imports nor exactly measure the mix of electricity imports and exports in overall power supply to California consumers.

IMPEDANCE

Impedance is the opposition to electricity flowing in an electric circuit due to resistance and reactance. Resistance opposes electricity flows due to friction within the conductor. Reactance exists because Alternating Current (AC) voltage and current sinusoidal waveforms can move out of synch.

Reactance exists because AC rather than Direct Current (DC) technology became the standard for US power systems within the first few decades of US power system technology evolution. US electric power systems originated with Thomas Edison deploying DC electric technologies in 1882. These DC power systems were designed to operate with steady positive current (amperes) and an associated steady voltage (volts). However, the challenge of voltage level conversions and efficient transmission flows drew battle lines for the "war of the currents" that broke out during the first fifteen years of the US electric industry. George Westinghouse advocated making Nikola Tesla's AC technology the standard for power systems. By the end of the 1890s, AC technology had won the war.

The nature of voltage and current differentiate alternating current (AC) versus direct current (DC) power system technologies. AC current and voltage reflects the underlying physics (Faradays law of induction) whereby rotary motion interactions between an electric circuit and a magnetic field produce coincident sinusoidal waveforms for current and voltage. The figure below shows the wave pattern of electric current that starts at zero and then increases to a maximum positive value before declining past zero and reaching a maximum negative value before returning to zero and shows that the generation of sinusoidal waveforms for voltage are coincident with the cycle phases of the current waveforms. The cycle causes current to swing from positive to negative values and hence, these oscillations are the source of the nomenclature of "alternating current" power supply. In all US electrical interconnections, this cycle repeats 60 times every second—a frequency of 60 hertz. Electrical power output and consumption is measured by watts; the product of voltage and current.



Reactance opposes alternating current because the presence of a magnetic or electric field in proximity to a conductor creates inductive and capacitive characteristics respectively, in parts of the grid, that cause the sinusoidal waves of voltage and current to move out of phase—producing reactive power—and thus, reactance in the conductor. Reactive power reduces the power delivered to consumers and hinders the required synchronization of the sinusoidal waveforms for voltage and current across all electric generators located throughout the AC grid. Power system operators manage reactive power in the grid through operational techniques and equipment such as phase-shifting transformers, static VAR compensators, and flexible AC transmission technologies that alter impedance and thus power flows throughout the grid.

The California Energy Commission recognizes that the complexity of the physics, technology and operations of the Western Interconnection prohibits an accurate differentiation of the CO_2 emission content of imports. The CEC had to consider the CO_2 emission intensity of imports without CARB affiliation assignments because the electricity generated by affiliated sources does not always reconcile with actual electricity flows into California. The existence of imports without CARB assignments of specified affiliated sources drove the CEC to assess the possibility of differentiating the source of these unspecified imports and the CEC concluded:

> Indeed, it is impossible to do so. The result is that about 15 percent of the energy imported into California cannot be determined to be from a specific fuel type. Therefore the 'unspecified' energy could be any mixture of coal, wind, solar, natural gas-fired, or any source, or none of these.[48]

The bottom line is that it is not clear how power plant ownership changes or altered contract pathways would alter the flow of electricity throughout the Western Interconnection or alter the CO_2 emissions associated with the electricity imports into California.

The inability to accurately tag power flows from sources to sinks in a highly-integrated power system also makes the impact of power plant closure on the CO_2 emission content of imported electricity unclear. For example, CARB CO_2 emission accounting treatments drove Southern California Edison and the Los Angeles Department of Water and Power (joint majority owners) to close the Mohave coal-fired power plant located in Nevada. This affiliation change led to dismantlement of the power plant in 2005. In this case, the affiliation change removed a single source of generation from the security constrained economic dispatch of the Western Interconnection AC power system and thus, distributed the impact of the removal of this power plant's output based on the resulting reconfiguration of power flows across the entire Western Interconnection determined by the underlying physics. The implication is that the full reduction in the carbon content of electricity was not constrained to electricity flowing just into California. However, since the CARB CO_2 emission accounting method does not require reconciliation with actual change in electricity flows, the CARB assigned the full impact of the CO_2 emission reduction to just California electricity imports.

The exact mix of imports and in-state generation serving California consumers is uncertain. The physics determining actual power flows in the Western Interconnection prevent a meaningful split of the California power supply between in-state and out-of-state electric generation. Multiple pathways connect California to the rest of the Western Interconnection and the underlying physics of power flows means that sometimes transmission interties spanning the state borders are exporting electric energy while other interties are simultaneously importing electric energy across state borders. The physics governing electricity grid pathways means that some of the electric energy imported into California can loop back in the grid as part of the state's simultaneous electric energy exports.

In 2014, California in-state electric energy generation was 196,194 GWh and California exported 10,737 GWh and imported 109,947 GWh. If California electric energy exports came entirely from in-state generation sources, then the remaining 185,475 GWh of in-state generation supplied 62 percent of the electrical energy needs of California consumers. But, loop flows could increase this percentage of in-state consumer electricity demand satisfied by in-state generation to as much as 66 percent.

The conclusion is that California policy evaluations of the impacts of the emission performance standards on the CO_2 emissions associated with electricity imports are unclear for two reasons. First, the fundamental misalignment between CARB affiliation

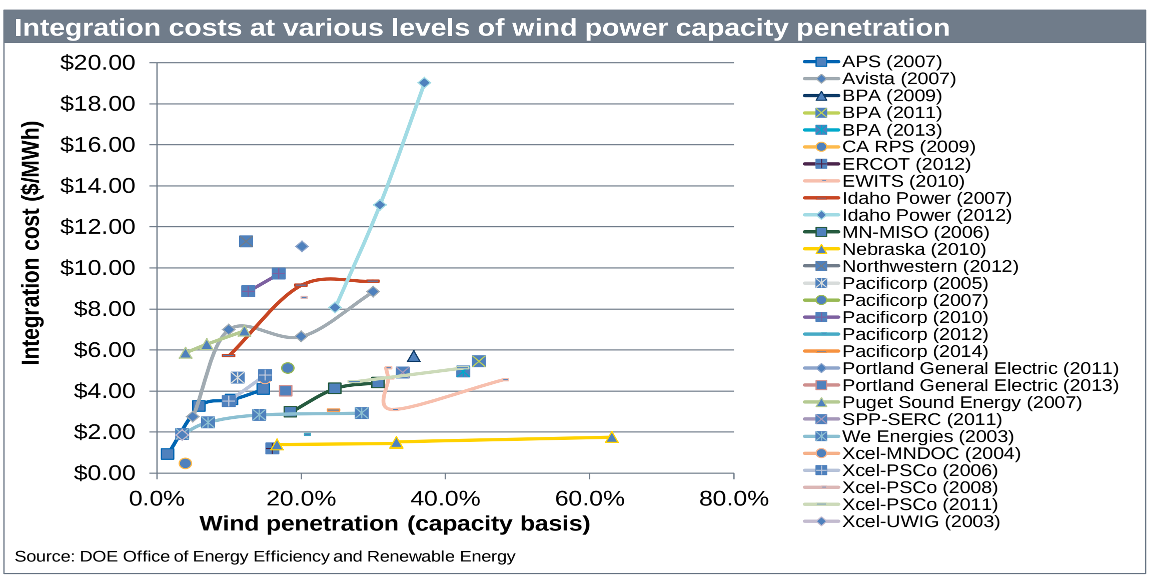
[48] California Energy Commission, *Actual and Expected Energy from Coal for California,* December 7, 2015

assignments and actual power flows significantly obfuscates the CO_2 emission intensity of actual imports. Second, the exact mix of imports and in-state generation is uncertain due to the existence of loop flows. Together, these misalignments and uncertainties cause a lack of situational awareness regarding the impact of electricity sector climate policies on the one-third of power supply imported into the state.

Real time situational awareness of the balance between power system demand and supply is a fundamental requirement to operate a power system. California formulated its renewable power mandates ahead of conducting engineering studies of the impact these mandated intermittent sources of power supply would have on the real time balancing of power system demand and supply.

The US Department of Energy collected separate studies of power system renewable integration costs. The studies did not use common approaches or employ equivalent assumptions and the power systems had different initial conditions. Despite these differences, the studies indicated two general findings. First, the introduction of increasing amounts of intermittent wind and solar generation into a power system makes balancing electric demand and supply in real time more difficult and expensive. Second, the integration cost increases, at an increasing rate, as the intermittent renewable generation share increases. Figure 27 illustrates that integrating greater penetrations of intermittent electric supply typically generates positive and increasing costs.

FIGURE 27



Reliably balancing power system demand and supply requires having enough available generating capacity at any point in time to meet the aggregate consumer demand. If adequate capacity is available, then stable power system operation requires dynamic adjustments to available capacity utilization to accommodate continuously changing demand and supply conditions. For example, when power system demand increases relative to supply, then the consequence is a decline in voltage and frequency across the power system. In this case, stabilizing voltage within tolerable bounds requires the rapid (automated reactions within milliseconds) ramping up of output from less than fully loaded electric generation resources connected to the grid. Conversely, when changes in conditions cause an increase in power system supply relative to demand, then the compensating response requires ramping down output or curtailing some generation resources in the grid to maintain balance in real time.

Conventional wind and solar resources are intermittent power supplies. These resources affect the complex economic trade-offs involved in efficient power system operation. Economic trade-offs exist because a power system involves myriad possible combinations of intermittent and dispatchable power plant utilization rates that altogether can match aggregate power system supply to power system load—the aggregate consumer demand—at any point in time. Achieving the most efficient trade-offs involves dispatching power plants to equalize the short-run marginal production costs across all available resources. To do this involves knowing the "merit order" that ranks generation sources by marginal cost at any point in time.

Grid security requirements constrain the economic dispatch of alternative generation resources based on the merit order. The least-cost generation mix may involve power flows from sources to sinks that create insecurity in some transmission pathways. Insecurity exists because if something unexpectedly changes, then physics will cause power flows to reroute along grid pathways at roughly the speed of light. These rerouting power flows can overload some transmission pathways and cause further rerouting, and subsequently cause more transmission line overloads that can build into a cascading power system failure. Power system operators employ computer simulations of power system operations to assess insecurities and to alter the amounts of generation from power plants in different locations throughout in the grid. Given the underlying physics of power flows, altering the location of sources of generation will alter the electrical flows along available pathways to consumers. Grid operators manage reactive power and adjust out-of-merit order dispatch to reconfigure power flows and transmission line loadings to achieve an outcome that is secured against major contingencies. This outcome is the "security constrained economic dispatch of an AC power system."

The problems created by the misalignment between California renewable power mandates and the time dimension of power system operations challenges power system operators in the Western Interconnection. However, the job of managing the security constrained economic dispatch in the Western Interconnection does not fall on a single centralized control center. Instead, the job falls on the coordinated actions of 38 different balancing authorities with control centers located throughout the regional grid. The California Independent System Operator (CAISO) is one of the 38 balancing authorities in the decentralized management of the scope of operations within the Western Interconnection.

The CAISO is a non-profit corporation formed in 1998 to manage grid operations, grid planning, and electricity markets across about 80 percent of the electricity sector within the political boundaries of California, and a small part of the power grid located in Nevada.

CAISO found that the misalignment between the time pattern of wind generation and customer needs created increasingly difficult operational challenges as climate policies drove intermittent wind technologies to account for more than 90% of renewable generation increases in California from 2001 to 2013.[49] In particular, California wind driven electric output tends to decline in the morning hours as aggregate consumer demand increases, and tends to increase in the evening as aggregate consumer demand declines.[50] The CAISO managed this growing mismatch between the time profiles of renewable resource output and power system customer needs primarily through compensating output adjustments from operationally flexible, dispatchable electric generating technologies. The primary source of this wind integration support involved natural gas-fired generating technologies, and as a result,

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[49] California Energy Commission. *California Renewable Energy Statistics and Data*. http://energyalmanac.ca.gov/renewables/index.html.

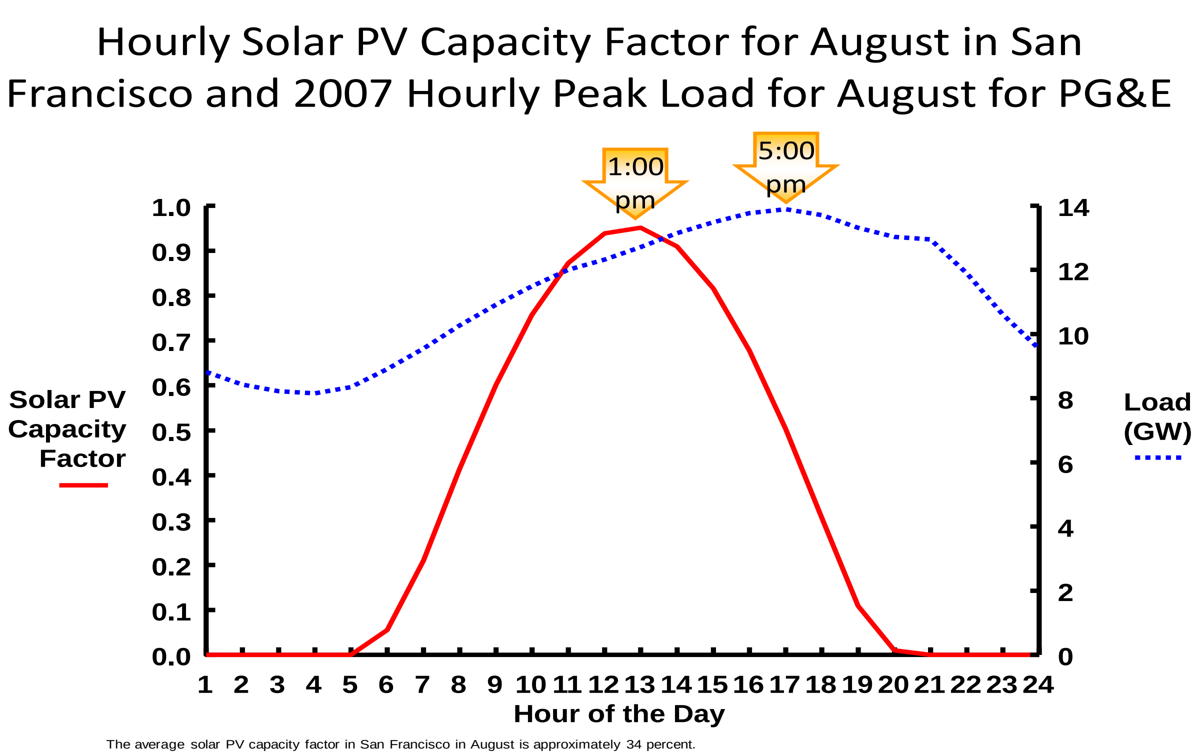
[50] Coughlin, Katie, and Joseph H. Eto., *Analysis of Wind Power and Load Data at Multiple Time Scales*, Lawrence Berkeley National Laboratory, December 2010. http://www.nerc.com/FilingsOrders/us/FERCOrdersRules/Analysis_Wind_Power_and_Load_Data.pdf.

these power plants experienced more frequent power plant startups and shutdowns as well as more varied ramp ups and ramp downs of output to compensate for variable intermittent wind generation output.

Early on, CAISO's experience indicated that the ability of the available operationally flexible, dispatchable generating technologies to back up and fill-in for intermittent renewable diminished as the intermittent resource generation share increased. The difficulties of integrating increasing amounts of intermittent wind resources into California's power system led to a policy shift that encouraged non-wind renewable resources. Experience showed that with peak demand in the summer, the California power system could reduce some of the stress from wind integration by increasing the solar share of the renewable output. As a result, in 2003, California instituted a solar generation "carve out" to reserve a share of the renewable portfolio requirement for non-wind technologies.

Increasing the solar generation share in California production did not mitigate the operational challenges of intermittent wind renewable generation. Instead, the operational problems expanded from managing electric energy supply variability to also managing power supply reliability. As Figure 28 shows, California load profiles typically reach peak demand in the late summer afternoon period when solar irradiation—and thus solar electric energy generation— is rapidly waning. Reliability involves having enough available generating capacity plus the necessary reserve margin to create a high probability that available capacity can match the instantaneous aggregate power system demand. Therefore, maintaining system reliability required that California have enough conventional generation resources at the ready to fully back up and fill in for declining solar capacity during the peak demand periods.

FIGURE 28



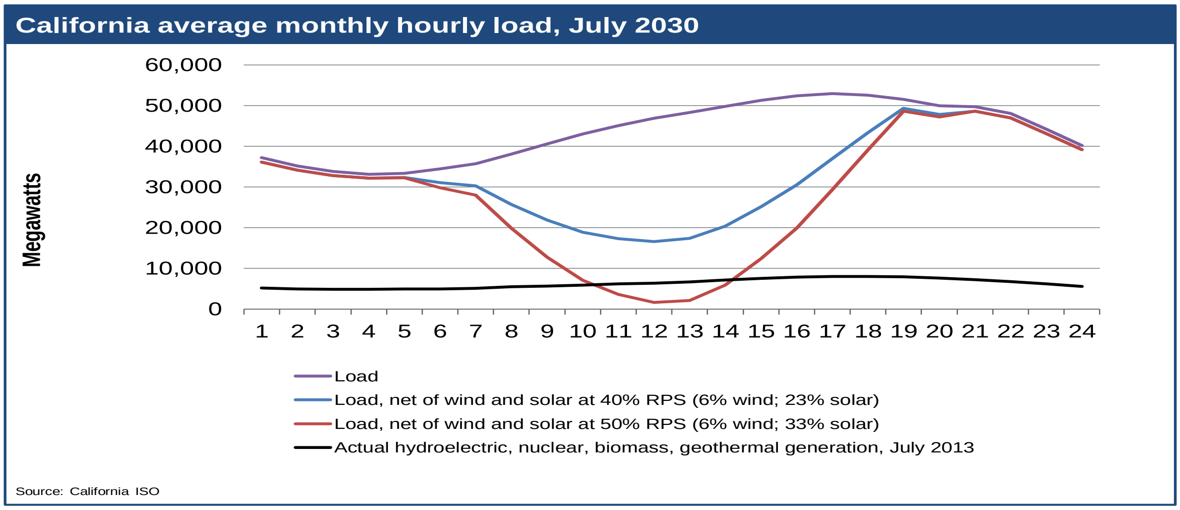
In 2007, five years after California set its 20% renewable portfolio target and several years after initiating the integrated resource planning interventions to diversify the variable generation mix, the California independent system operator conducted and released its first study of the operational challenges from integrating more wind and solar renewable resources into its power system.[51] The study indicated that an increase of intermittent generation share to around 12 percent would increase the probability of "over-generation" conditions, where inflexible power supply would exceed power system load, and force wind and solar generation curtailments. Subsequent assessments indicated that addressing the over-generation problem would require additional flexible generation resources to integrate the additional variable resources in the supply pipeline being generated by the renewable portfolio requirements.[52]

Despite accumulating evidence of operational challenges and the need for additional actions to address these challenges, the optimistic policy formulation created a blind spot to these mounting operational challenges and consequently, the California political process simply continued to ratchet up the renewable generation mandates. In response, the CAISO initiated analyses of the operational challenges associated with the ever-increasing renewable policy goals.

In 2013, the major California utilities sponsored a study led by Nancy Ryan, a former CPCU Commissioner to analyze the consequences of operating the CAISO with the 33% renewables generation share mandate.[53] The study report, submitted to the Western Conference of Public Utility Commissioners, indicated significant cost consequences resulted from the impact of intermittent generation on the power system net load. The graphic illustrating this mounting challenge showed how the shape of net load changed as the generation share of intermittent renewables increased. Subsequent versions of this curve—as illustrated in Figure 29—showed that as the generation share of renewables increased, the electric system net load shape increasingly resembled the shape of a duck, and as a result, the chart became known as the "Duck Curve." The Duck Curve illustrates the mounting operational challenges posed by the increasing frequency, and duration, of over-generation conditions as well as the increasingly dramatic ramping requirements imposed on the flexible, dispatchable generating resources.

FIGURE 29

[51] California ISO., *Integration of Renewable Resources: Transmission and Operating Issues and Recommendations for Integrating Renewable Resources on the ISO-Controlled Grid*, November 2007. http://www.caiso.com/1ca5/1ca5a7a026270.pdf.
[52] California ISO. *Integration of Renewable Resources: Operational Requirements and Generation Fleet Capability at 20% RPS*. 2010.
[53] Energy Environmental Economics, *Investigating a Higher Renewables Portfolio Standard in California*, January 2014



Initially, the most economic approach to coping with the Duck Curve was through the construction of additional operationally flexible, dispatchable power supply in California. The most cost effective technology to do this was natural gas-fired generating technologies. Consequently, the move toward more intermittent renewables created a greater reliance on flexible natural gas-fired combustion turbine and combined cycle generating technologies. From 2002 to 2014, in-state natural gas-fired electric capacity expanded by over 40 percent and the in-state generation share of natural gas-fired technologies increased from 50 to 60 percent.[54] Ironically, the expansion of natural gas-fired capacity to integrate wind and solar intermittent electric energy output contributed to the transformation of the state's electric energy production portfolio into a fossil fuel dominated generation mix.

CAISO faces mounting operational challenges because natural gas-fired technologies integration capabilities are limited. Coping with the California Duck Curve in the decade ahead involves an increasing need for the power system operator to increase electric output by close to fifty percent in just three or four hours as the sun sets and solar PV output predictably declines as consumer demands increase.

The limits of flexible dispatchable generation resources means that integrating higher renewable generation output requires the more frequent curtailment of some of the intermittent generation. Although 2014 was a year of severe drought that reduced the non-dispatchable flow of hydroelectric generation, nevertheless, with just an 11 percent in-state wind and solar generation share, over-generation conditions forced the CAISO to curtail some non-dispatchable generation in each month. In 2015, CAISO reports monthly renewable curtailments ranged from 5 GWh to over 45 GWh and the accumulated annual curtailment amounted to close to 300 GWH.[55] California in-state hydroelectric generation in 2014 was almost 14 TWh below the most recent 15-year average and a recovery from these recent drought conditions will increase the over-generation problem.

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[54] California Energy Commission, Energy Almanac
[55] California ISO, *Market Performance Report April 2016*, May 2016, pg. 18.

Looking ahead, the California mandate to reach a 50 percent renewable generation share by 2030 will likely not involve much expansion of either small hydroelectric resources, geothermal or biomass resources. Therefore, meeting the 50 percent renewable policy mandate will likely involve more than doubling of the existing 10,476 MW of in-state intermittent wind and solar generating resources. However, analyses of the operational challenges of California's 50 percent renewable target for 2030 led the CAISO to release a study on July 12, 2016 showing that the ISO would need to curtail 10,000 MW of wind and solar production over large periods of the year. Since the marginal cost of wind and solar electric is near zero, the CAISO calculates the cost of replacement power for renewable curtailments. The CAISO estimates that California will incur between 1 and 1.5 billion dollars in annual curtailment costs to manage the renewable development pipeline being generated by the renewable output targets for the year 2030.[56]

CAISO responded to the operational challenges of the 50 percent renewable portfolio requirement in California with an initiative to dilute the impact of renewables by expanding the scope of ISO operations and planning into a much larger, multi-state region. In 2014, CAISO offered participation in an expanded Energy Imbalance Market (EIM) to neighboring parts of the Western Interconnection. PacifiCorp, NV Energy, Puget Sound Energy and Arizona Public Service joined into the expanded the short-run management of power system flows. Participation was encouraged by the opportunity to use the EIM to manage their own intermittent resource integration challenges as well as to gain access to greater amounts of California's surplus generation at prices well below the full cost of the power supply.

In the years to come, managing the renewable output increases in California requires more than just an expanded short-run energy imbalance marketplace. The broader regional power system will need additional investment in flexible power supply and in the transmission network transfer capability. As a result, expanded the long-run planning function of a regional ISO creates the need to manage the cost burden of the additional investments required to configure the Western Interconnection power system to absorb the growing surplus output of wind and solar resources driven by California climate policy initiatives.

The lesson is that misalignments between California electric climate policy initiatives and the underlying physics and technologies of power systems contributed to the track record of policy underperformance. The implication is that a successful expansion to a regional ISO requires resolving regional power system investment cost allocation issues. Therefore, the jury is still out regarding whether this strategy to expand the scope of the ISO will work. Yet even if successful, the California ISO transition into more centralized regional ISO will take a decade or more to unfold and the ability to absorb the California demand and supply imbalances will only work if the rest of the states in an expanded regional ISO do ***not*** follow California's example of mandating 50 percent renewable generation shares and replicating misalignments with the underlying physics and technology of the power system.

Lesson 3: Optimistic policy formulations tend to focus on metrics that hinder situational awareness of electric sector climate policy underperformance.

Changes in the California electricity CO_2 emission footprint metric indicate significant policy underperformance. Yet, California is still widely regarded as being on the leading-edge electric sector climate policy initiatives due to a focus on numerous common climate

[56] California Independent System Operator, *The Impacts of a Regional ISO-Operated Power Market on California*, July 12, 2016.

policy metrics other than the electricity CO_2 emission footprint. As Table 3 shows, California electric policy initiatives across the past dozen years score favorably against common policy metrics.

TABLE 3

Common electric sector climate initiative metrics	
	California
1. Legislation to address climate change, including the electric sector	✓
2. Increasing renewable and distributed generation shares	✓
3. Increasing spending on electric consumption efficiency programs that slow load growth or delink increased electric consumption from economic growth	✓
4. Setting new single day renewable generation records	✓
5. Deployment of declining Levelized Cost of Energy (LCOE) wind and solar resources	✓
6. Creation of clean energy jobs with associated positive multiplier impacts on the local economy	✓
7. Negotiated closures of the largest single point sources of CO2 emissions	✓
8. Research and development initiatives to accelerate technological innovation in batteries and renewable electric generating technologies	✓
9. Putting a price on CO2 emissions	✓
10. Reduction in CO2 emissions from an above-trend historical point in time (for example, emissions in 2005)	✓

However, California's track record based on these common metrics does not support rejecting the optimistic bias hypothesis for climate policy formulation. This bias leads to setting policy targets and selecting evaluation metrics that are prone to overstating policy performance and obfuscating policy shortcomings. Therefore, a lack of situational awareness regarding policy underperformance due to a focus on climate policy metrics other than changes in the electricity CO_2 emission footprint may not simply be an oversight, and instead appears to be a predictable outcome.

CARB CO_2 emission accounting treatments produce inaccurate policy evaluation metrics by tending to overstate policy performance through shuffling of power supply resource assignments. "Resource shuffling" reassigns electric supply affiliations from above average carbon intensive sources to below average sources without reconciling these reassignments to the changes in actual electricity flows into California. This resource shuffling produced a 45 percent decline in the CARB assigned CO_2 emission intensity of imports from 2002 to 2014 and produced an annual rate of decline that was over twice the pace of the decline for Western Interconnection electric generation CO_2 emission intensity outside of California.[57] As a result, resource shuffling based evaluations situated California as leading, rather than lagging, the US reduction in electricity CO_2 emission footprints from 2002 to 2014.

CARB CO_2 emission accounting treatments understate the California climate policy challenge. CARB accounting treatments that assign CO_2 emissions by affiliation produced a 2014 electric sector emission level of 88 million tons of CO_2 that accounted for 20 percent of California's annual GHG emission level. [58] On this basis, the 2014 California electricity CO_2 emission footprint was 5,011 lbs. CO_2 per person. This CARB based accounting based metric is 12 percent lower than the 5,724 lbs. CO_2 per capita California electricity CO_2 emission footprint produced by assigning the undifferentiated CO_2 per KWH of Western Interconnection electric generation outside of California to the electric energy imported into California while employing the same import share as the CARB evaluation.

Looking ahead, the expanded energy imbalance market will increase the degree of short-run integration of California demand and supply into broader power system operations and increase the difficulty of assigning electricity imports to specific sources. Therefore, the likely volume increase of unspecified power flowing into California will force the application of the undifferentiated CO_2 emission content of Western Interconnection electric production to account for the CO_2 emissions associated with an increasingly larger proportion of California power supply in the years ahead.

The lesson is that focusing on common climate policy metrics rather than the electricity CO_2 emission footprint, along with CARB's selection of CO_2 emission accounting treatments that enables resource shuffling, creates a lack of situational awareness regarding policy impacts.

Lesson 4: Picking winning technologies and mandating generation shares based on simple time ignorant LCOE comparisons produce inefficient electric generation portfolio mixes.

The California Clean Energy and Pollution Reduction Act of 2015 policy formulation reflected the expectation that a costless substitution of renewable power technologies for conventional generating technologies is possible, based upon the simple time ignorant levelized cost of energy (LCOE) assessment indicating "grid parity" in electric generation costs. This cost assessment creates the expectation that mandating increasing renewable generation shares rather than conventional electric generation resources will not result in higher overall electric production costs.

Cost comparisons employ a technique known as "levelizing" the annual costs of production because cost factors, such as fuel costs and tax expenses, change across the operating life of an electric supply resource. To facilitate comparisons, analysts calculate a constant annual dollar per MWh amount that has the same discounted value as the expected uneven year–to-year cost stream—thereby "levelizing" the annual cost.

These simple time ignorant LCOE cost assessments involve estimating the unit costs of a power generation technology output (dollar per MWh) in each year of a power plants expected operating life without regard to the when the power is produced relative to

[57] California Environmental Protection Agency, Air Resources Board, California Greenhouse Gas Emission Inventory—2016, June 2016, http://www.arb.ca.gov/cc/inventory/data/data.htm and California Energy Commission, Energy Almanac, September 2015, http://energyalmanac.ca.gov/electricity/total system power. html.
[58] Ibid.

consumer needs. Instead, simple time ignorant LCOE compares the costs of generating technologies in a stand-alone operating mode at specified utilization rates.

A simple time ignorant LCOE calculation mischaracterizes relative generating resource costs because the simple LCOE comparison does not provide the relative cost information necessary to ascertain the most cost effective approach to generating the varying amounts of electricity that consumers demand throughout the year. If the simple LCOE metric provided an accurate assessment of relative power supply costs, then the cost minimizing power system generation portfolio would involve only a single fuel and technology with the lowest LCOE based on a utilization rate equivalent to the power system load factor (the ratio of average aggregate consumer demand to the maximum aggregate instantaneous consumer demand). For example, a power system with consumers demanding an average amount of electric output equal to 60 percent of their aggregate peak demand would get the lowest possible electric supply cost by relying only on the generating technology with the lowest LCOE at a 60 percent utilization rate. If that technology happened to be wind turbines, then the simple LCOE cost assessment indicates the least supply option is a 100% wind generating supply portfolio. Yet, such a system based on time ignorant cost assessments would fail to deliver electricity to consumers when they wanted it.

The deficiencies of simple LCOE cost comparisons led economist Paul Joskow to conclude:

> The prevailing approach that relies on comparisons of the "levelized cost" per MWh supplied by different generating technologies, or any other measure of total life-cycle production costs per MWh supplied, is seriously flawed.
>
> Levelized cost comparisons are a misleading metric for comparing intermittent and dispatchable generating technologies because they fail to account for differences in the production profiles of intermittent and dispatchable generating technologies and the associated large variations in the market value of the electricity they supply. The extension and use of levelized cost comparisons to intermittent generation has been a mistake and tends implicitly to overvalue intermittent generating technologies compared to dispatchable alternatives.[59]

Simple time ignorant LCOE cost assessments distort cost comparisons because intermittent generation resources such as wind and solar do not influence the costs of meeting the power system objective the same way as dispatchable power resources. Intermittent and dispatchable electric energy generating technologies do not have equivalent power supply costs to provide consumers with electric energy when they want it even if they have the same simple time ignorant LCOE. For example, a simple time ignorant LCOE cost assessment could produce an LCOE for solar PV equal to the LCOE for biomass generation, but the biomass technology is more cost-effective in delivering electric supply because it can follow the changing needs of electric consumers through time much better than the solar PV technology whose electric output varies with changes in the intensity of solar irradiation through time.

The shortcoming of the simple time ignorant LCOE cost estimate is that it indicates the cost to produce electric energy at a utilization rate without regard to the when the power is produced relative to consumer needs. Therefore, simple LCOE cost assessments are at odds with three factors that shape the time dimension of electricity cost assessments for power systems.

[59] Paul J. Joskow, *Comparing the Costs of Intermittent and Dispatchable Electricity Generation Technologies,* Massachusetts Institute of Technology, Center for Energy and Environmental Policy Research, Reprint Series Number 231 (9 February 2011), pp. 1, 2, and 4.

1. Intertemporal consumer preferences for electric energy use cause aggregate power system consumer demand to vary through time and thus, require the lowest cost electric supply portfolio to match load in real time.
2. Generating technology energy production costs vary with utilization rates because a fundamental tradeoff exists between up front capital costs and the efficiency of transforming primary energy inputs into electric energy.
3. The cost and performance of load following electric generating technologies sets the competitive cost and performance benchmarks for available electric energy storage options and demand-side options.

Simple time ignorant LCOE cost assessments not only overvalue wind and solar generation because of the omission of the time dimension on power supply costs, but also overvalue intermittent power supply resources because of the omission of the cost impacts from integrating these power supply technologies into the overall supply portfolio. These integration costs are not part of a simple time ignorant LCOE cost comparison that quantifies an electric generating technology LCOE under a given set of conditions in a stand-alone mode of operation.

Taking the time dimension into account means that the lowest cost power supply portfolio will not be made up entirely of the single technology with the lowest simple LCOE at the power system load factor. Instead, the lowest cost power supply typically involves an integrated mix of technologies that satisfy the power system objective function with an explicit time dimension.

The objective of a power system is to minimize the cost of providing consumers with the electric services that they want and ***when they want them,*** at a price that internalizes all costs, subject to security of supply constraints in an AC power system. Therefore, an efficient electricity sector climate policy incorporates a simple extension of this objective--minimize the power system objective cost function by fully internalizing the cost of CO_2 emissions in the security constrained, economic dispatch of a cost-effective supply portfolio in an AC power system.

Cost assessment approaches exist to find the least-cost mix of production technologies in a supply portfolio that satisfies the objective function of a power system. Power system cost minimization results involve a mix of electric generating technologies with varied utilization rates that produce electricity to balance real time varying demand levels with limited economic inventory options.[60] Under these conditions, the least-cost alignment of power supply to demand patterns means that all power plants do not operate in a stand-alone mode and thus, will not necessarily operate at their optimal plant factors or minimum levelized costs. However, since this is a least-cost solution to the power system objective cost function, the utilization of generating technologies below their stand-alone maximum efficiency rate is not a source of economic inefficiency.

A least-cost electric generating supply portfolio typically incorporates a diverse set of generating technologies because the integration of available technologies lowers overall production costs compared to a portfolio composed of a single technology. A least-cost power supply portfolio will typically include some, but not necessarily all, of the available electric generating technologies. This means that cost-effective conventional generating technology integration typically lowers overall production costs. As a result, integration of mandated technology generation shares above the least-cost supply portfolio renewable share will predictably result in an increase in overall production costs compared to the least-cost outcome. The increased costs come from conventional

[60] Williamson O E, "Peak Load Pricing and Optimal Capacity under Indivisibility Constraints" AER, vol. 56 no 4, September 1966, pp 810-827

generating technologies backing up and filling in for intermittent generation to keep aggregate power supply equal to aggregate power demand at any point in time.

The lesson is that simple time ignorant LCOE cost comparisons do not accurately reflect the economic competitiveness of alternative electric generation technologies in meeting power system objectives. The implication is that simple time ignorant LCOE based electric sector climate policy formulations will likely produce inefficient outcomes that overvalue intermittent renewable technologies and produce a generation mix with a renewable generation share greater than the cost minimizing share.

Lesson 5: Increases in electric consumer consumption efficiency beyond what consumers choose to do themselves involves positive and increasing costs.

A cornerstone of the optimistic formulation of the California Clean Energy and Pollution Reduction Act of 2015 involves the expectations that a reduction of electricity sector CO_2 emissions through ratepayer-funded efficiency programs can generate consumer net savings, rather than costs. From this perspective, investment to increase electric consumption efficiency beyond what consumers choose to do themselves provides a "net negative cost" policy option.

The legislative sponsors of California's Clean Energy and Pollution Reduction Act of 2015 relied on influential studies to support the idea that policy initiatives designed to pursue massive efficiency gains can generate consumer savings rather than costs. The sponsors cited the IEA cost assessments. The IEA constructed a climate policy assessment of a "Bridge Scenario" that increased energy efficiency enough to halt GHG emission growth by 2020, while also decoupling global economic growth from increases in fossil fuel within the next decade, and altogether, produced economic savings rather than costs. [61]

The hypothesis that a massive pool of net negative cost efficiency gains exists rests on three conditions. First, widespread opportunities must exist for consumers to make profitable electric consumption efficiency investments. Second, consumers make chronic mistakes—either because they are poorly informed or irrational--when they decide to forgo these opportunities and invest in something else. Third, cost effective policy options exist to resolve these consumer mistakes.

Accepting the hypothesis that climate policy initiatives can increase electric energy consumption efficiency beyond what consumers choose to do themselves at net negative cost requires rejecting the proposition that electric consumer behavior is consistent with orthodox economic models of reasonably well-informed and rational consumer behavior that leads consumers to invest in some, but not all, available potentially profitable investments.

A rational and well-informed consumer demand for electric services involves the selection of specific technologies to transform electric energy into electric services. Typically, alternative technologies exist and the cost of electricity is just one of the input costs to produce the desired output. For example, a consumer may desire the electric service of space conditioning with an air conditioner. A competitive air conditioner marketplace confronts the consumer with a trade-off because a more electric efficient air conditioner is more expensive to purchase than a less efficient unit, all else equal. Consequently, purchasing a more efficient electric technology involves an evaluation of the discounted value of the expected lower, but uncertain, future electric energy operating costs versus the higher, and certain, current upfront capital cost. A well-informed and rational electric consumer will balance expected costs and benefits in determining how much of their scarce capital to invest in air conditioning unit efficiency.

[61] International Energy Agency, *World Energy Outlook Energy and Climate Change Special Report*, 2015, pg. 74, 106

The example of rational well-informed consumer deciding how much to invest in an air conditioning unit illustrates two important implications. First, the best investment does not always involve choosing the most energy efficient unit available. Second, when a consumer takes some hard-earned cash and invests it to produce benefits in the future--with expected total value (net present value) exceeding the upfront cost—this decision is ***not*** described as "pursuing a net negative cost option." Instead, such an action is typically called "pursuing a potentially profitable return on investment."

Often, a consumer is seen as making a mistake when an available investment to increase energy efficiency is not undertaken even though the expected rate of return is above the consumer's incremental borrowing cost. But such consumer behavior is not necessarily a mistake or at odds with orthodox economic theory. The typical consumer has good reason not to run up their outstanding debt to their credit limits to invest in as many potentially profitable investments as possible—including all potentially profitable electric energy efficienty investment opportunities.

Consumers have different preferences regarding the risks of holding outstanding debt to finance investments with uncertain returns. Typically, consumers prefer not to take on as much debt as lending institutions are willing to provide to them because they do not prefer the risks and return characteristics of the overall portfolio containing as many investments as possible. The implication is that rational consumers choose to make some but not all potentially profitable investments, including some but not all potentially profitable energy efficiency investments based on their risk tolerance. From this perspective, consumers are not making a mistake when they forgo potentially (but not guaranteed) profitable investment opportunities. This rational consumer balancing of risks and returns means that investment opportunities to increase energy efficiency should not be viewed in isolation, but rather analyzed as part of a consumer's management of a scarce resource—capital—in an overall investment portfolio with an associated aggregate risk profile.

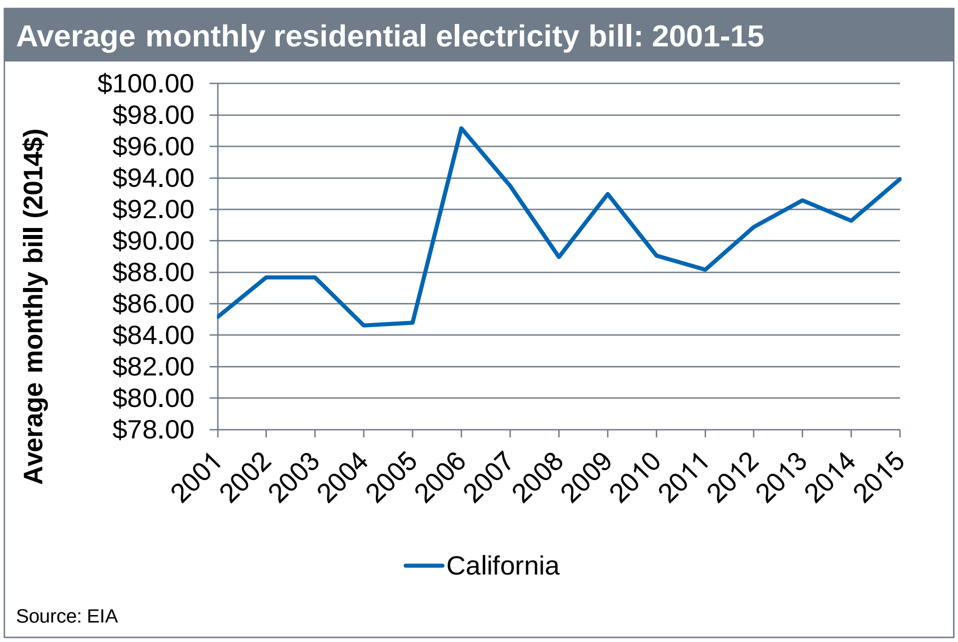
A purely theoretical development of rational decision making is not enough to reject the hypothesis that poorly-informed and irrational consumers are making chronic mistakes that lead to underinvestment in electric consumption efficiency on a massive scale. Similarly, anecdotes of consumer mistakes and capital market imperfections are not enough to reject the hypothesis that consumer efficiency investment reflects well-informed and rational decision making. These alternative hypotheses involve two testable propositions. First, if consumers are well-informed and rational, then we would expect to see evidence of consumers selecting more efficient end use technologies in electric power systems with persistently higher retail prices compared to electric systems with persistently lower prices, all else equal. Such evidence would not exist if consumers chronically fail to make correct decisions regarding efficiency investments and in doing so, create an accumulating massive pool of potential net negative cost efficiency gain opportunities. Second, if the negative cost efficiency hypothesis were correct then states with efficiency programs can simply split the savings with consumers and end up lowering monthly power bills.

A testable proposition is the existence of a significant inverse long-run relationship between the electricity price levels and electricity consumption levels, all else equal. Persistent electric price differences exist across US states and consumers in all states choose from a common slate of electric end use technologies with varying electricity efficiency characteristics. Since end uses with higher efficiency provide greater benefits relative to costs in high priced states, well-informed and rational consumer behavior would result in a significant inverse relationship between electricity price and consumption, all else equal. In contrast, ill-informed and irrational consumers would not respond in a predictable way to real electric price increases.

A cross-sectional regression analyses can isolate the relationship between electricity prices and consumption levels that reflect long-run end use efficiency choices. Holding all else equal requires including the other determinants of electric consumption in the statistical analyses. The electricity demand module of the Electricity CO_2 Emission Footprint Pathway Model provides a statistical analysis of consumer responses to changes in prices while quantifying the impact of other significant variables. The quantification indicates that when all else is held constant, a higher electricity price causes a statistically significant inverse response in consumer consumption reflecting rational decisions regarding end use efficiency investments.

The expectation of lower electricity bills from cost effectively redressing net negative cost efficiency gains did not materialize across the past dozen years in California. As Figure 30 shows, the average residential monthly electricity bill, adjusted for inflation, increased from 2002 to 2014.

FIGURE 30

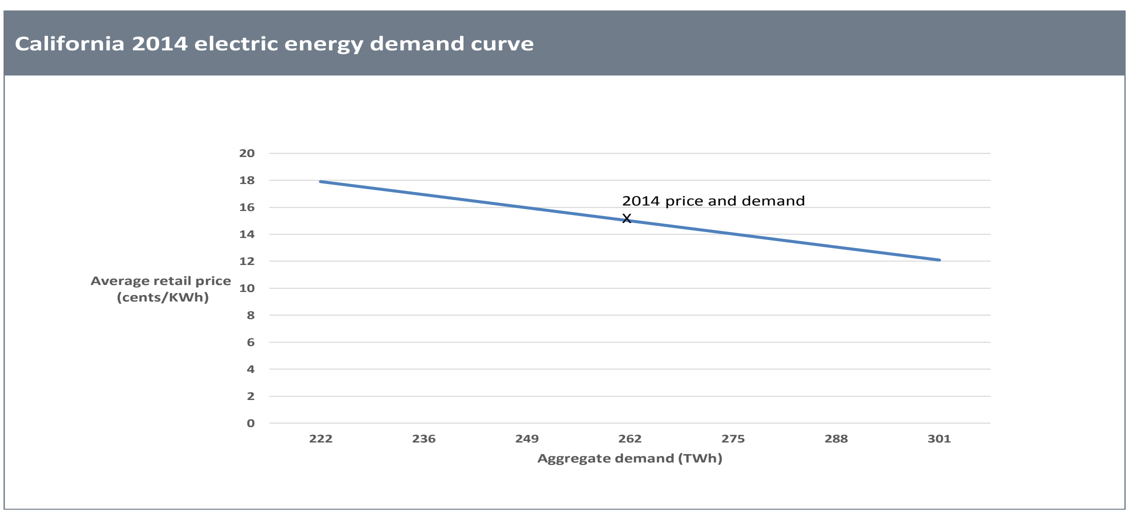


The negative cost efficiency hypothesis is an appealing idea, but statistical analysis indicates that it appears to be too good to be true. The existence of sizable, statistically significant and negative long-run price elasticities of demand across consumer segments supports the characterization of consumers as reasonable well-informed and rational. Similarly, the shortfall in negative cost based policy formulations from delivering lower monthly electricity bills supports rejecting the idea that a massive accumulated pool of net negative cost efficiency options exists.

California electric climate policy formulation appears to incorporate cognitive dissonance regarding consumer efficiency cost functions. On one hand, the existence of massive market failure due to the inability of consumers to respond to market price signals formed the basis for the no cost policy formulations promising monthly electric bill reductions. On the other hand, California also intervened into the electricity marketplace with a CO_2 emission cap and trade program beginning in 2013. This market intervention reflected the assessment that climate change involves a market failure due to the omission of CO_2 emission costs in market prices—including retail electric prices. This approach reflects the expectation that well-informed and rational consumers are underinvesting in electric consumption efficiency and overconsuming electric energy because the price signal is too low. The implication is clear—the California policy initiative to put a price on CO_2 emissions to correct this market flaw can only succeed if electric consumers are well-informed and respond in a rational way to the CO_2 emission costs added to the prices that they face. If this approach makes sense, then it probably does not make sense to also try to tap into a massive net negative cost pool of efficiency gains produced by ill-informed and irrational consumers.

Rejecting the ill-informed and irrational consumer hypothesis means that a downward sloping electricity demand curve can reliability characterize California consumer electricity demand. Figure 31 shows the 2014 long-run California electricity demand curve that incorporates the estimated negative long-run price elasticity of demand relationship with other factors held at 2014 levels based in the statistical analyses in the E-Path demand module (see Chapter 4). The demand curve reflects a consumer class consumption weighted retail price and elasticity estimates with the slope being determined by applying the elasticity at the mean formula to the actual 2014 level of price and demand.

FIGURE 31

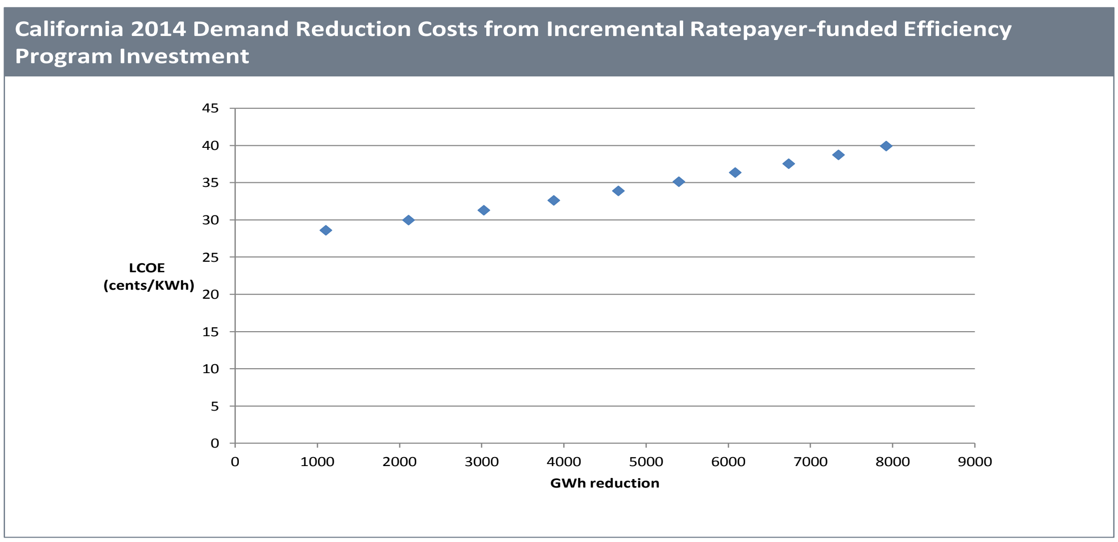


Consumer choices regarding investments in electric end use efficiency locates aggregate consumer demand on the demand curve. All else equal, an increase in consumption efficiency beyond what consumers choose to do themselves causes the location of aggregate demand to move along the demand curve up and to the left. Such a move occurs when rate payer-funded efficiency programs impose a fee on consumers that circulates back as subsidies for the purchase of more efficient appliances that decreases the apparent cost of efficiency investments relative to the expected benefit.

The demand module equations quantify the negative impact on residential and commercial electricity consumption caused by investment in ratepayer-funded electric consumption efficiency programs, all else is held constant. These statistical relationships allow calculation of the cost curve to reduce electricity consumption through increases in ratepayer-funded efficiency program investments.

Figure 32 shows an estimate of the cost curve associated with incremental net investment to increase electric consumption efficiency beyond what consumers choose to do themselves in California, holding all else equal to 2014 demand conditions.

FIGURE 32



The cost estimate of California 2014 demand reductions from incremental ratepayer-funded efficiency program investment reflect three analytical steps. First, the E-Path demand module equations for the residential and commercial customer segments are solved with actual 2014 independent variables, including the existing $7.2 billion ($2014) net investment in ratepayer-funded efficiency programs. Second, the 2014 equations are resolved with accumulating 10 percent increments of this 2014 net investment until the net investment is doubled. The Y-axis indicates the expected 2014 GWh reductions and as Figure 32 shows, the E-Path demand module indicates that a doubling of net investment in California ratepayer-funded efficiency programs in 2014, with all else held constant, would have resulted in about a 3 percent reduction in overall California electric demand in that year. Third, a calculation of the annual costs and demand reductions associated with the incremental investment over the investment expected lifetime allows calculation of the annual levelized cost per KWh of the reduced energy consumption, shown on the x-axis. In this example, the LCOE of the efficiency programs were not increased to include any consumer contribution to the efficiency investment.

Ratepayer-funded efficiency programs involve collecting fees from consumers and returning the fees as efficiency investment subsidies. Yet, even if this can be accomplished without losses in recirculating the fees, residential consumers—as utility maximizers—are not indifferent to the outcome nor made better off. Instead, a rate payer-funded program produces a "deadweight" economic loss by moving the residential consumer to a position on the demand curve that consumers revealed was less preferred by the choices they would have made in the absence of the efficiency program. The E-Path demand module allows quantification of ratepayer-funded efficiency program driven move along the aggregate residential consumer demand curve and the associated deadweight loss.

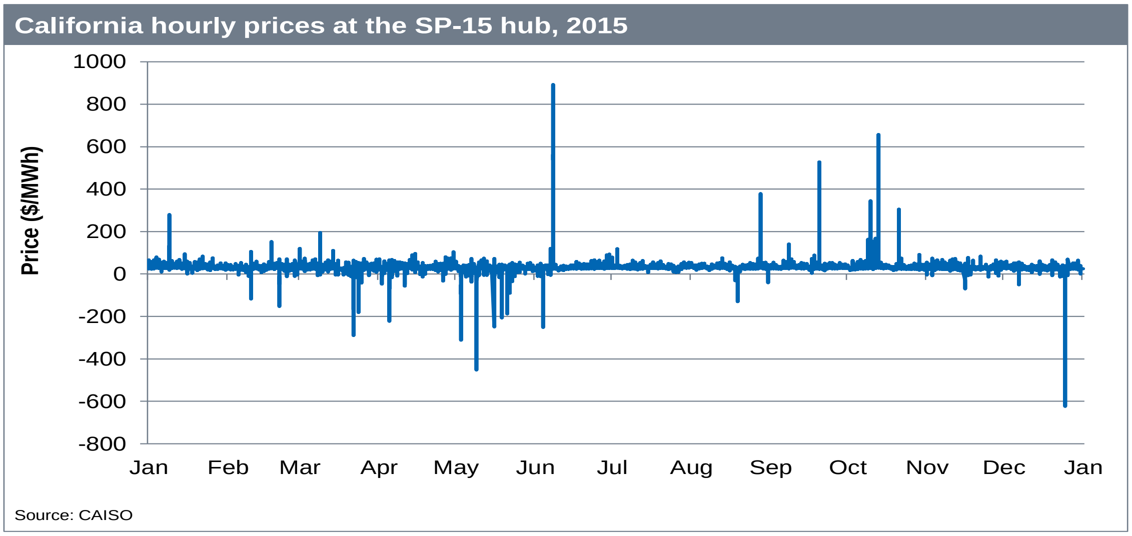
The lesson is that California faces a positive and increasing cost to move electric consumer consumption efficiency beyond what consumers choose to do themselves. The implication is that an efficient climate policy approach would balance the associated marginal costs of demand-side options to increase efficiency with supply-side options to reduce CO_2 emission intensity, to achieve any level of CO_2 emission reduction at the lowest possible cost.

Lesson 6: Environmental policy interventions can suppress price signals, distort electricity market outcomes, and produce a CO_2 emission boomerang.

The ratcheting up of California's electric sector climate policy ambitions began just five years after California began restructuring its electric sector to rely more on market forces and less on regulatory processes to shape outcomes. The simultaneous implementation of electric industry deregulation and more environmental regulation produced predictable interactions between market forces and policy interventions in the wholesale electric marketplace. Market interventions to mandate subsidized renewable generation and demand-side management programs altered the interaction of demand and supply. Mandates of renewable power supply exist to increase generation shares beyond an unfettered market outcome. These policy initiatives add resources into the marketplace with short-run marginal costs of production close to zero. All else equal, these mandates shift the supply curve in a competitive marketplace and cause wholesale market-clearing prices to decline compared to the price level expected without market interventions. In addition, as the share of wind and solar generation increases and suppresses prices, the increase in wind and solar output also alters the output pattern for load following power plants due to the need for more frequent start-ups and shut-downs as well as more ramping to provide more varied electric output. This operating mode is more expensive and as a result, reduces competitive generator cash flows from the wholesale electric energy marketplace. Suppressed prices and higher variable costs squeezed market-based electric supply cash flows.

Subsidies magnify the market distortions of renewable mandates. As wind and solar generation shares increase, an increasing number of hours arise when these renewable supply resources are bidding against each other to set the market price. During these periods of time, the zero short-run marginal costs of these technologies would be expected to drive market-clearing prices to zero. But, renewable power resources fulfilling mandates also are typically subsidized based on the volume of output—for example, through production tax credits. Under these conditions, rival subsidized generators find they can make money by bidding negative prices because it is still profitable to produce power if the value of the subsidy per unit of output is more than enough to cover the cost of paying someone to take the electric output. Under these conditions, competitive forces drive market-clearing prices to negative levels that further squeeze market-based electric supply cash flows. The increasing frequency of negative wholesale electric energy prices clearing the market is an indicator of the distortion created by mandates of output volume subsidized renewable generation. For example, Figure 33 shows the negative price distortions that appeared in California during 2015.

FIGURE 33



Market-based electric generator cash flows and profitability decline due to the suppression of market-clearing wholesale energy prices. Normally, the profitability of an investment provides a market test for economic viability. This expectation arises from the "textbook" market result. In this case, competitive forces drive rival suppliers to bid to supply output based on their short-run marginal cost of production. As a result, the market supply curve reflects the aggregate short-run marginal costs of competitive suppliers and the intersection of this market supply curve with the market demand curve determines the market-clearing price. These price signals create competitive forces that move the market into a long-run demand and supply balance where—in the textbook case—demand and supply curves intersect at a unique price level that equates short-run marginal costs to long-run marginal costs. Under these long-run competitive conditions, the market clearing price provides sufficient cash flows to cover all costs of efficient competitive producers. As a result, a supplier earning a competitive return from a well-functioning marketplace provides a market-based test of economically efficient production. Conversely, markets distortions that suppress market-clearing prices will not produce unfettered textbook market outcomes and therefore, the presence of market distortions prevents market based cash flow profitability from providing a reliable metric for the economic viability of a generating plant.

Wholesale market price distortions cause economic inefficiency. Textbook market-clearing prices that balance long-run demand and supply pace economically efficient power plant retirement and replacement. An economic power plant retirement occurs when the present discounted value of the going forward costs (including a competitive return on capital) are above present discounted value of future market cash flows. In the textbook case, future cash flows reflect market equilibrium prices equal to long-run marginal costs (a price level that supports the replacement cost of electric production capability). Market interventions that distort market-clearing prices downward lead to economic inefficiency when they cause power plants to retire even though it is less expensive to continue to operate them compared to the cost of replacing them.

Mandates of subsidized renewable resources in California distort market prices and lead to inefficient electric generation portfolios. Mandates and subsidies cause wind and solar resources to exceed the efficient market generation share. Wind output patterns in California tend to suppress of electric energy prices disproportionately in off peak periods. As a result, this price suppression disproportionally reduces cycling and baseload power plant cash flows from the levels expected in an efficient market outcome. These price signals lead to a less efficient generating portfolio mix because they encourage uneconomic retirements that produce a mix with too few baseload technologies and too many peaking technologies compared to a least-cost electric supply mix of baseload, cycling and peaking technologies.

An unintended consequence of the uneconomic retirement of baseload power plants due to market distortions from mandates for volume-based subsidized intermittent generation is the "CO_2 emission boomerang." The boomerang happens when price suppression and cash flow reductions caused by subsidized renewable mandates, intended to lower CO_2 emissions, instead cause the uneconomic retirements of zero emission power supply along with replacement power resources that produce CO_2 emissions.

California experienced the CO_2 emission boomerang with the closure of the San Onofre nuclear power plant. Inadequate market cash flows were one of the reasons behind the closure in 2012 of the San Onofre nuclear power plant. The closure of this nuclear power plant removed 8 percent of non-carbon emitting generation from the California in-state supply portfolio and caused a 30 percent increase in the carbon intensity of in-state generation. An impact assessment from the Energy Institute at Haas School of Business at University of California Berkeley found the San Onofre closure caused an increase in California in-state natural gas-fired generation and did not provide savings to consumers because the closure caused an estimated 15 percent increase in California electric generation costs by contributing to the 31 percent increase in wholesale power prices in 2013 versus 2012.[62]

Although California's electric sector climate initiatives caused a CO_2 emission boomerang, nevertheless, the Associated Press reported that when Edison International's announced that it was prematurely closing its San Onofre nuclear power plant, California's environmental community celebrated even though its closure meant that GHG emissions associated with electric supply would go up as a result.[63]

California environmental policy interventions show evidence of reducing the cash flows of the cycling generating resources providing the critical function of backing up and filling in for the intermittent renewable generation. The California Independent System Operator Department of Market Monitoring reported a chronic shortfall of cash flow for the existing capacity that provided the operational flexibility to integrate large volumes of intermittent generation.[64] The report concluded that providing adequate cash flows to compensate for these essential supply services required some form of longer capacity payment or contracting mechanism. Several ad hoc solutions involving reliability-must-run contractual payments designed to prevent market based cash flow retirement decisions for essential power supply resources came into existence with numerous California power plants. The CAISO intervened into the marketplace in August 2011 to address cash flow suppression by providing additional compensation to some load following

[62] Lucas Davis and Catherine Housman, *Market Impacts of Nuclear Power Plant Closure*, American Economic Journal: Applied Economics, 8 (2), 92-122, April 2016.
[63] Gillian Flaccus, and Amy Taxin, *Environmentalists Celebrate Nuclear Plant Closing*, Associated Press, June 8, 2013. http://topheadlinesdaily.com/environmentalists-celebrate-nuclear-plant-closing-abc-news/.
[64] California ISO Department of Market Monitoring, *2013 Annual Report on Market Issues and Performance*, April 28, 2014.

power suppliers through an interim flexible ramping payment. A Federal Energy Regulatory Commission approved flexible ramping product tariff replaced the interim payments effective November 1, 2016.[65]

The lesson is that California electricity climate policies that mandate subsidized renewable power production significantly suppress market clearing wholesale energy prices and increase conventional load following generator operating costs. The implication is that the market distortions mean that profitability of competitive power plants does not provide an accurate market test of economic viability of competitive generators. Market interventions are needed to remedy the cash flows squeeze and avert uneconomic nuclear power plant retirements that produce a CO_2 emission boomerang effects, and to maintain the flexible generation needed in the supply portfolio to efficiently follow changes in net load.

Lesson 7: Uncoordinated piecemeal climate policies are inefficient.

California climate policies are making CO_2 emission reduction more expensive than necessary. A measure of the inefficiency is the differences in the cost of CO_2 emission abatement across different California climate policy initiatives.

The environmental benefit of a reduction in CO_2 emissions is the same regardless of the source. An efficient climate policy outcome would involve pursuing each alternative CO_2 emission reduction option to the point where the marginal cost to CO_2 emission reduction was equal across all options. An inefficient result exists when the marginal cost of CO_2 emission reduction is unequal across options because the opportunity exists to reduce the resources being deployed in the higher marginal cost option and increase deployment of resources to lower marginal cost option, and produce greater CO_2 emission abatement at the same total cost.

One of the current parts of the California electric sector climate policy is a cap-and-trade program for CO_2 emissions that includes electric sector CO_2 emissions. This initiative conducts periodic auctions to set the price of reducing an additional tonne of CO_2 emissions from the electricity sector and the 2013 auction set a cost of $12.73 per tonne.[66]

Another part of the California electric sector climate policy is the mandate of wind and solar power supply. Mandates are employed because otherwise the expected source of new power supply would likely come from the lower cost fossil generation technologies. Current estimates of new renewable and fossil technologies generation cost and performance characteristics are available from the CEC.[67] Analyzing the difference in unsubsidized electricity supply costs between the most cost effective option and the renewable alternative and dividing this cost difference by the difference in CO_2 emission levels yields the implicit cost of reducing a tonne of CO_2 emissions from the electricity sector with this policy initiative.

This cost assessment follows this approach but rather than use the simple time ignorant LCOE cost comparison to calculate the implicit cost of renewable generation CO_2 emission abatement, this cost assessment focuses on combinations of technologies that can meet an increment of electric demand (KW) and the associated recurring annual time pattern of energy consumption (KWh). This approach incorporates the time dimension of balancing power demand and supply in real time. An increment of 1 KW of electric

[65] https://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleRampingProduct.aspx
[66] California Air Resources Board, *California Cap-and-Trade Program Summary of Joint Auction Settlement Prices and Results*, November 2016, https://www.arb.ca.gov/cc/capandtrade/auction/results_summary.pdf
[67] California Energy Commission, Final Staff Report, *Estimated Cost of New Renewable and Fossil Generation in California*, March 2015, CEC-200-2014-003-SF, http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SF.pdf

demand at the power system peak in California will produce an average annual increment of load of roughly 0.6 KW, requiring resources with load following capability in generating the associated 5,256 kWh throughout the year.

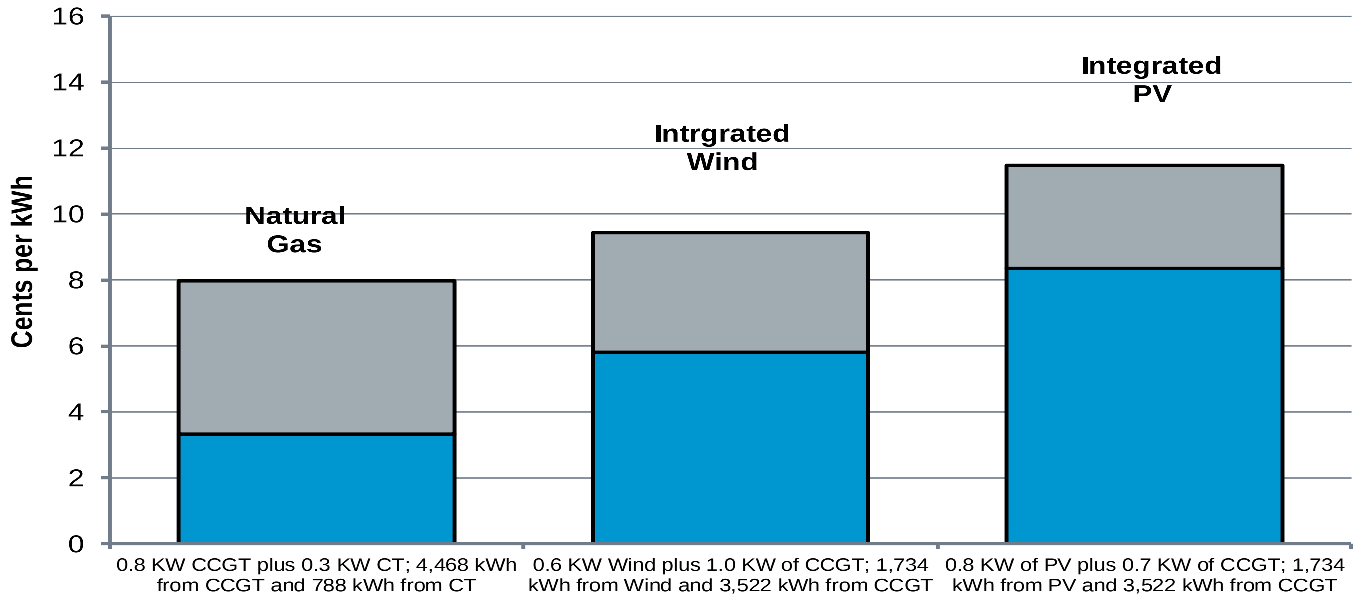
Employing current electric supply technology cost and performance parameters in the integrated cost assessment indicates that the lowest cost source of power supply to meet this incremental demand is through a combination of peaking and cycling natural gas-fired technologies. In this example, the cost-effective option involves integrating a natural gas-fired combustion turbine unit with a natural gas-fired combined cycle unit to meet the increment of demand. The peak demand is met using a 10 percent derate of these units combined capacity. The integration of these technologies provides enough flexibility to follow the pattern of consumer demand through time. As a result, the combustion turbine utilization meets 30 percent of energy demand while combined cycle unit supplies the rest.

The utility scale wind or solar technology cannot reliability supply the increment of demand because of the misalignment of when consumers want the electricity and when the wind blows or the sun shines. Therefore, the renewable technologies are integrated with the natural gas-fired combined cycle technology to create a generation mix capable of meeting the peak demand as well as provide the electric energy in line with time dimension of consumer demand. To meet the peak demand, the wind technology capacity is derated by 67 percent and the solar capacity by 41 percent. In each renewable case, the renewable technologies operate at expected plant factors (wind 33%) and solar (25%) to generate half of the energy demand while the natural gas-fired technologies follow load and generate the remaining half of the energy demand.

Figure 34 shows the results of the integrated LCOE cost assessment. Using the emission rate of 118 lbs. CO_2 per MMBtu for natural gas consumed to generate electricity provides quantification of the difference in CO_2 emission between these options.

FIGURE 34

Integrated Busbar Costs to Meet an Increment of Power Demand



Notes: CCGT = conventional combined-cycle gas turbine; CT =conventional combustion turbine; PV = single axis 20 MW photovoltaic, Blue bars are fixed costs including capital costs, taxes, fixed O&M, and insurance and property tax. Grey bars are variable costs including fuel and variable O&M.

Installed cost based on CEC Final Staff Report, *Estimated Cost of New Renewable and Fossil Generation in California*, March 2015

This time integrated LCOE cost assessment shows an implicit cost of reducing an incremental tonne of CO_2 emissions through the renewable mandate initiatives in California is $75 for wind and $160 for solar.

Inefficiency arises from the difference in the cost of reducing one tonne of CO_2 emissions across California electric sector climate initiatives because, as this example illustrates, the resources spent on the renewable mandate initiatives could be shifted to buy allowances through the cap-and-trade program and produce more than ten times the CO_2 emission reduction for the same cost.

The lesson is that uncoordinated climate policy initiatives generate inefficient policy outcomes. The Little Hoover Commission, released a study in 2012 that observed, “Policies and regulations affecting electricity have been piled upon each other piecemeal.” The study went on to say that “The state has not produced a comprehensive assessment of the total cost of implementing this group of policies.”[68] The Implication is that business-as-usual policy approaches will continue to make CO_2 emission reduction more expensive than necessary in California.

Lesson 8: Electricity climate policies can produce inequitable cost burdens.

California moved to the leading-edge of electric sector climate initiatives in 2002 even though its contribution to the US electricity CO_2 emission footprint was well below the US average. California likely moved ahead of other states because of its relative income position rather than its relative contribution to the global warming problem.

[68] Little Hoover Commission, *Rewiring California: Integrating Agendas for Energy Reform*, December 2012.

The willingness to pay for environmental actions increases with income level.[69] California had among the highest income per capita in the United State in 2000. Political processes tend to reflect the relative influence of varied stakeholders and higher income stakeholders tend to exert disproportionally more influence. Consequently, California's early actions on electric sector GHG emissions relative to other states likely arose because of disproportional influence of relatively high income stakeholders for whom doing something about global warming is a priority. Although California retail electric prices were over fifty percent higher than the US average in 2002, California nevertheless moved ahead because the optimistic climate policy formulations grossly underestimated the cost of climate initiatives and obfuscated the impact on monthly consumer electricity bills.

Although higher income stakeholders in California may have a greater willingness to pay, the greater than anticipated climate policy impacts on electricity prices and the associated higher monthly bills distributed a proportionately larger share of the cost burden on lower income households whose electricity expenditures are a larger percentage of household spending compared to higher income households. This regressive outcome raises fairness concerns.

Equity concerns from the impact of political actions on electricity bills are not new. California had well-developed cost allocation principles for its electricity sector before it began to implement climate policy initiatives. Figure 35 provides California's latest articulation of cost allocation principles.[70] Principle 3 reflects the long-standing goal of allocating costs based on cost responsibility.

FIGURE 35

California: Ten principles of optimal residential rate design

1. Low-income and medical baseline customers should have access to enough electricity to ensure that basic needs (such as health and comfort) are met at an affordable cost.
2. Rates should be based on marginal cost.
3. Rates should be based on cost-causation principles.
4. Rates should encourage conservation and energy efficiency.
5. Rates should encourage reduction of both coincident and non-coincident peak demand.
6. Rates should be stable and understandable and provide customer choice.
7. Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals.
8. Incentives should be explicit and transparent.
9. Rates should encourage economically efficient decision-making.

[69] Steven E. Sexton and Alison L. Sexton, *Conspicuous Conservation: The Prius Effect and Willingness to Pay for Environmental Bona Fides,* April 21, 2011.

[70] California Public Utilities Commission. *Rulemaking 12-06-013*, filed 21 June 2012. http://www.leginfo.ca.gov/pub/13-14/bill/sen/sb_1051-1100/sb_1090_cfa_20140327_115550_sen_comm.html

10. Transitions to new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates, and minimizes and appropriately considers the bill impacts associated with such transitions.

Misalignments exist between California electric climate policies and the cost allocation principles. California electric sector climate initiatives provide net metering to rooftop solar installations with compensation based on retail rate levels. These policy initiatives are at odds with the "beneficiary-pays" principle that those responsible for costs ought to pay for them.

Net metering at full retail rates provides a subsidy from electric consumers without rooftop PV to electric consumers with rooftop PV installations. Household ownership correlates with income levels. Therefore, higher income households are more likely own a home capable of PV rooftop installations than lower income households. In California, rooftop solar PV resources cost roughly 50 % more than an equivalent solar farm due to the substantial economies of scale in solar PV supply.[71] Consequently, net metering at retail prices creates a subsidy for economically inefficient solar technologies that flows from lower income households who do not own rooftops to higher income households that do. The California Public Utilities Commission commissioned a study, released in October 2013, on the costs and benefits of its net metering program. The report found that by 2020 the net metering policies would cost the state almost $1.1 billion a year and impose roughly $360 million in additional costs on non-solar electricity customers based on the inherent cross-subsidization.[72]

Cross subsidies affect cost burdens. Within the Western Interconnection, California consumers are selling wind and solar over-generation in the imbalance market at a fraction of what the state mandates require consumers to pay for it. In effect, California consumers are cross-subsidizing the renewable electric consumption of consumers in the rest of the Western Interconnection. However, since the alternative to selling below cost is renewable output curtailment, the energy imbalance transactions are reported to Californians as operational "savings."[73] This accounting treatment creatively characterizes policy adjustments that reduce the inefficiencies of ongoing policy initiatives as savings. Such characterizations hinder the situational awareness of the total costs of California electric sector climate policy initiatives.

The lesson is that climate policy cost burdens involve considerations of fairness. The implication is that misalignments between California climate policies and cost allocation principles along with inefficient policy outcomes are exacerbating the regressive cost burden of California electric sector climate policies.

[71] Interview with Jim Hughes, CEO, First Solar at IHS CERA Week, March 2013.
[72] California Public Utility Commission. *California Net Energy Metering: Ratepayer Impacts Evaluation,* Prepared for CPUC by Energy and Environmental Economics, October 28, 2013. http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=4292.
[73] California ISO July 28, 2016 press release

Chapter 4: Mapping efficient and effective pathways to reducing future electricity sector CO_2 emissions

The least-cost pathway to reducing electricity CO_2 emission footprints is not obvious because demand and supply-side options are numerous and complex. As a result, a price signal provides an efficient mechanism to coordinate an efficient mix of demand and supply-side factors to map the least-cost pathway to achieving electric sector climate policy goals. Mapping the least-cost pathway to reducing future electric sector CO_2 emissions relies on an orthodox economic perspective that:

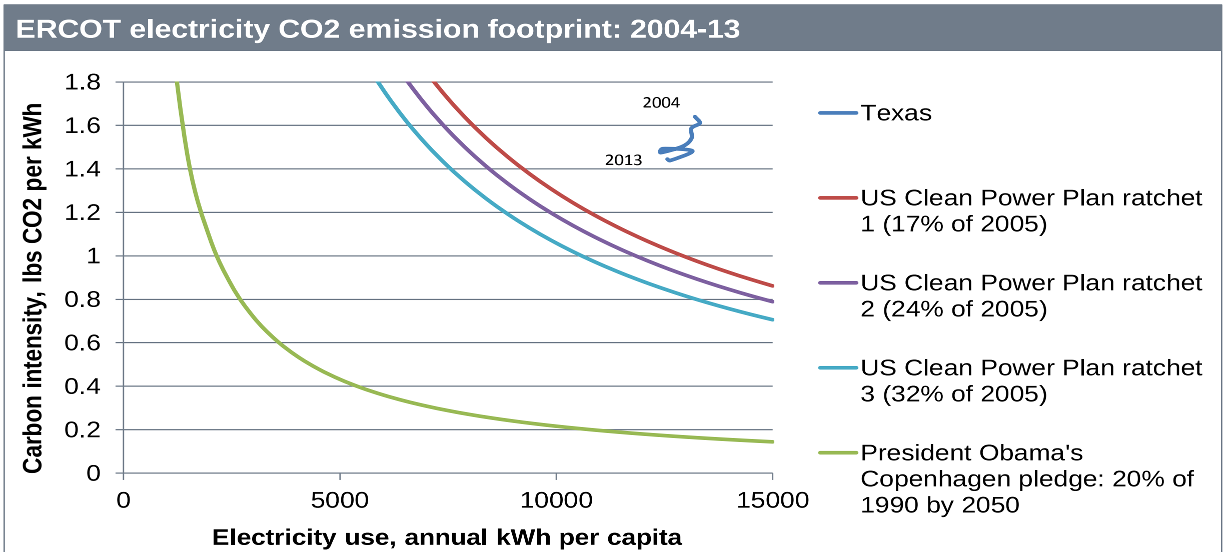
> The most efficient and effective way to reduce CO_2 emissions is to impose an appropriate charge on CO_2 emissions while eliminating the distortions of command and control climate policies such as mandates and subsidies.

This approach allows quantification of the impact, in the absence of market distortions, of incrementally higher CO_2 emission charges on the power system least-cost demand and supply-side factors that determine future CO_2 emission footprints. The analysis focuses at the power system level because the physical connection across a geographic area defined by the electrical system grid defines the interaction between electric demand and supply-side factors.

Electricity CO_2 emission footprint analysis framework

A power system electricity CO_2 emission footprint (annual pounds of CO_2 per person associated with electric production and consumption) is the product of a demand-side factor (annual KWh/person) and a supply-side factor (lbs. CO_2/KWh produced). Using the demand and supply-side factors as X and Y coordinates locates an electricity CO_2 emission footprint in a Cartesian plane. Changes in the demand and supply-side factors cause changes in a power system electricity CO_2 emission footprint and the sequential locations trace an electricity CO_2 emission footprint pathway through time. For example, Figure 36 illustrates the electricity CO_2 emission footprint pathway over the interval from 2004 to 2013 for the Electric Reliability Council of Texas (ERCOT).

FIGURE 36



Note: EIA data downscaled to be proportionally consistent with ERCOT data (ERCOT represents 85% of Texas load).

Figure 36 also shows isoquants (curves convex to the origin) comprised of the combinations of demand and supply factors that produce the same electricity CO_2 emission footprint. In this example, the frontiers represent climate policy goals based on the 2015 US Clean Power Plan along with President Obama's 2009 Copenhagen pledge to reduce US GHG emissions 80 percent from 1990 levels by the year 2050 (the isoquant reflects a 40% allocation of the Copenhagen emission goal to the electricity sector). These climate policy frontiers illustrate that isoquants closer to the origin represent lower electricity CO_2 emission footprints and that a pathway toward lower electricity CO_2 emission footprints involves movements toward the origin. One of these pathways is the least-cost combination of demand and supply side changes to achieve a given level of reduction in electric sector annual CO_2 emissions per capita.

The electricity CO_2 Emission Footprint Pathway Model (E-PATH) finds the mix of available power system demand and supply-side options undertaken between a base year and a future year that minimize the cost of providing consumers with the electric services that they want and when they want them, subject to power system security of supply constraints and the constraint that the consumer price for electric services equals the average total cost of producing the electric services.

The E-PATH cost analysis internalizes an exogenous CO_2 emission charge. The dollar per metric ton charge on CO_2 emissions is an exogenous parameter to an E-PATH solution. Sequential E-PATH solutions with CO_2 emission charges starting at zero and increasing by an exogenous dollar per ton increment alters cost minimizing demand and supply factors and generates a least-cost pathway to lowering electric system CO_2 emission footprints.

Timeframe for analysis

The cost to lower the future electricity CO_2 emission footprint is a function of the policy timeframe. E-PATH analysis begins with the selection of an analysis timeframe involving a historic year defining the "base year" and a specific "future year" establishing the end of the policy timeframe. The difference between the future year and the base year determines the lead time for CO_2 emission footprint reductions.

The selection of the base year defines the existing resource pool for legacy demand and supply-side resources. Legacy resources exist whenever some of the existing (base year) demand and supply resources remain economic to operate in the future year. Power supply technologies typically involve economic operating lives spanning decades and therefore, some of the dispatchable electric generating technologies operating in the base year will still be available and economic to operate in the future year. Similarly, some of the non-dispatchable sources of power supply operating in the base year, such as wind and solar resources, may also still be available and economic to operate in the future year. On the demand side, some of existing investments in ratepayer-funded efficiency programs may still be in place and impacting electric energy demand in the future year. Altogether these demand and supply-side resources constitute the legacy electric system resources available in the future year at their avoidable going forward costs.

Existing resources are legacy resources if their going forward costs in the future year supply portfolio are below replacement costs. Going forward costs do not include sunk costs that are incurred regardless of future resource operation. Consequently, these sunk costs exist regardless of any actions taken to address CO_2 emissions and thus are excluded from the E-PATH assessment of the costs involved in lowering future electricity CO_2 emission footprints. For example, the costs to complete the construction of a wind power project by the end of the base year are not included as costs associated with the reduction in the future electricity CO_2 emission footprint because the fixed costs of the wind project are sunk. In contrast, commitments exist to develop resources in the years ahead, but since these resources are not yet deployed, these planned resource expenditures are not considered sunk costs. For example, legislation exists that require some power systems to add greater amounts of wind and solar resources in the future. Since scarce resources to implement these plans have not yet been deployed, these costs are avoidable and thus, not sunk costs. A grey area involves demand and supply-side investments underway in the base year. For example, a wind power project that is under construction but not finished in the base year. Although the costs to finish the project are technically avoidable, nevertheless, the E-PATH treats the entire costs of the project as sunk costs because the momentum to project completion makes these costs, for all intents and purposes, sunk costs.

Initial conditions and exogenous parameters

Initial conditions incorporate legacy generating resources, legacy load modifiers and base year retail electricity prices split into initial production (variable) and non-production (fixed) components.

Exogenous parameters include future year electric demand determinants, legacy and new generating technology cost and performance profiles, legacy and new load modifier cost and performance profiles including wind, solar, and battery technologies, and the cost function to increase electric consumption efficiency through increased ratepayer funded efficiency net investments.

E-PATH solution algorithm

E-PATH employs an iterative non-linear optimization algorithm to minimize the cost of providing consumers with the electric services that they want and when they want them, subject to power system security of supply constraints and the constraint that the consumer price for electric services equals the costs of producing the electric services. All calculations involve real costs expressed in base year dollars. The E-PATH solution algorithm satisfies seven simultaneous relationships:

1. Power system aggregate consumer electric energy demand is a function of exogenous parameters and the endogenous parameters of retail price and net investment in ratepayer-funded efficiency programs. The annual electric energy level determines the level of hourly electric loads because it equals the area under the exogenous hourly aggregate load profile.
2. Power system annual hourly net load equals aggregate consumer load minus the level of exogenous and endogenous hourly net load modifiers. Exogenous load modifiers include legacy hydroelectric, wind, solar generation resources and legacy storage resources.
3. Endogenous dispatchable power supply resources equal the mix of resources that minimize the cost of electric supply to meet net load based on the time integrated levelized cost of supply screening curves generated by the cost and performance profiles of legacy and new generating technologies, firm capacity factors and the exogenous CO_2 emission charge.
4. Endogenous electric supply load modifiers include non-dispatchable resources such as wind and solar are equal to the amount of resources capable of lowering the overall cost of electric supply through their impacts on net load.
5. Endogenous efficiency load modifiers are equal to the net investments in ratepayer-funded efficiency programs capable of lowering the overall cost of electricity supply through their impacts on net load.
6. Storage technologies are deployed whenever these resources can lower the overall cost of electric supply through the reduction of the net load variation associated with the charging and discharging capabilities.
7. Retail price equals the exogenous unit component costs of transmission, distribution, metering and billing plus the endogenous unit costs of the average unit cost of dispatchable electric generation and the average unit cost of load modifiers. Average cost based electricity prices are a simplification of the complex mix of retail electric prices that range from average historic embedded accounting cost-based rates to real time marginal cost-based prices. Using average cost-based prices allows for the price feedback loop in the algorithm based on the historic price elasticity estimates from the E-Path demand sub model.

Baseline solution

The E-PATH establishes a baseline solution for the specified future year reflecting the maximum flexibility in deploying resources in the future. To do this requires determining a starting point in which nothing further is done to address climate change between the base year and the future year. Therefore, the E-PATH baseline is not anchored to a “business as usual” or “most likely” power system outlook across the E-PATH analysis timeframe. Instead, the E-PATH baseline anchors the analysis to initial conditions involving no continued command and control climate initiatives, no internalized charge for electric sector CO_2 emissions, and no additional scarce resources being deployed to address climate change.

Future year electric system demand and supply conditions will change from base year conditions even if nothing more is done to address electricity sector GHG emissions due to trends in non-policy determinants of electricity demand and supply-side factors. Therefore, the baseline solution indicates a "costless" move in the electricity CO_2 emission footprint that establishes the starting point to evaluate the costs of doing something to lower the future year electricity CO_2 emission footprint from what it otherwise would be.

Three modules quantify relationships supporting the E-PATH solution algorithm. The supporting models include:

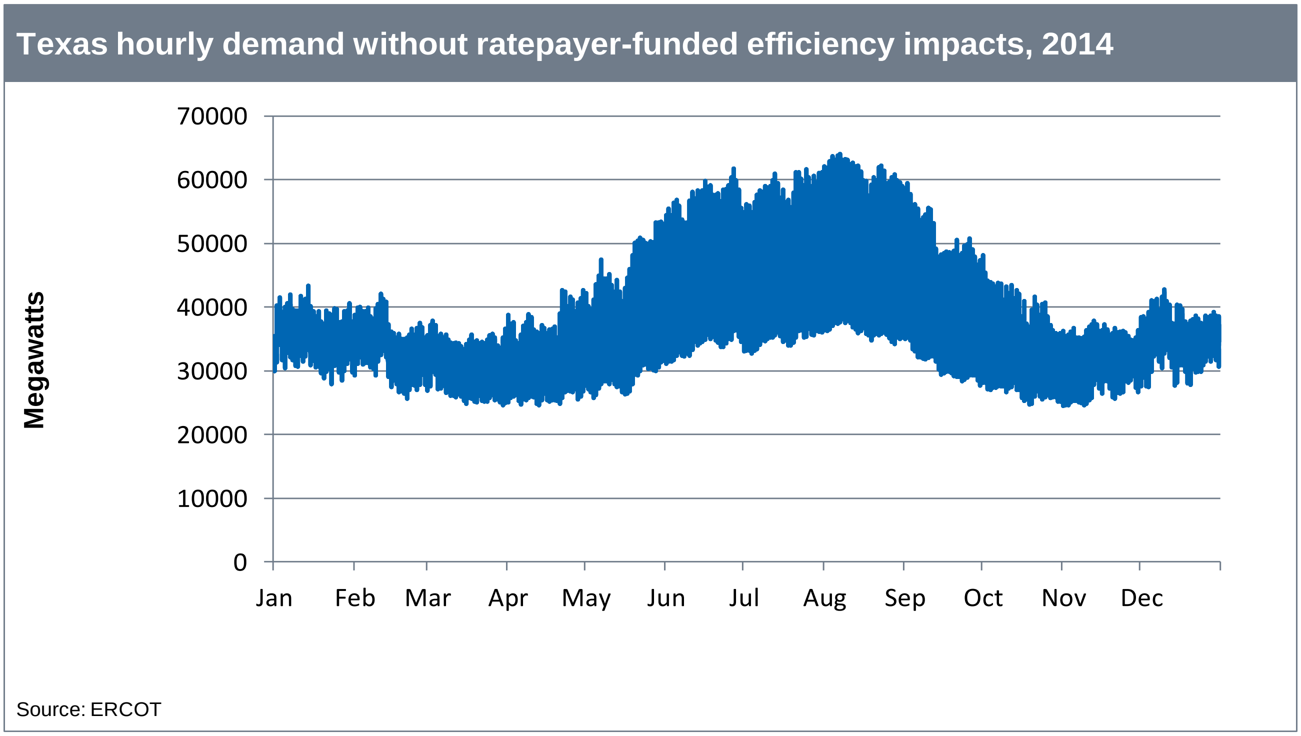
> **Electric service demand module**—quantifying the determinants of long-run demand for electricity services to establish baseline electricity demand, to determine the long-run price elasticity of demand, and to determine the positive and increasing cost function for increasing consumption efficiency through ratepayer-funded efficiency programs.
>
> **Dispatchable supply LCOE screening curve module**—quantifying the time integrated levelized cost of energy (LCOE) screening curves that make up the cost-effective electric supply portfolio.
>
> **Load modifier module**—specifying the cost and performance profiles of non-dispatchable resources and storage technologies.

Electric service demand module

Electricity demand at any point in time reflects the electric load (watts) input into the stock of electric end use technologies employed to produce the electric services consumers demand because they value the work provided by electric services more than the cost that they face for these electric services. The annual hourly aggregate consumer electric demand pattern already reflects the impact of demand shifting due to some consumers confronting time-of-use electricity prices. Most large commercial and industrial consumers with the flexibility to reduce their electricity bills by shifting demand in response to high frequency price signals elected such services decades ago. The remaining consumers, predominately small commercial and residential consumers, have far less flexibility to shift demand and lower electricity bills and have traditionally elected to continue to use the regulatory process to deliver stable and predictable retail rates.

The aggregate consumer demand for electricity is strongly seasonal and much of the variability is predictable due to variations in daylight intensity and seasonal temperatures. For example, Figure 37 shows the typical annual hourly pattern of demand for electricity in the ERCOT power system. The area under the aggregate load profile is the annual electric energy consumption (megawatt hours) with the reduction from rate payer-funded programs added back to show the total demand for electric services.

FIGURE 37



Several factors influence the level of annual electric energy consumption including the price of electric energy, level of household income, weather conditions, economic activity and the state of electric end use technologies.

A US state cross sectional regression analyses quantifies the relationships that are necessary to construct the parameters and relationships that are inputs to the E-PATH, including:

1. Base year electric service demands.
2. The future level of per capita electricity use based on independent variable inputs.
3. The cost to increase electric consumption efficiency beyond what consumers choose to do themselves.
4. The revealed value consumers place on electric energy consumption above what consumers pay for electric services.
5. Average temperatures—this parameter is set to normal levels (15 to 30 year averages) plus 1.8 degrees Fahrenheit to account for the impact of an increase of two-degrees Celsius in the average global temperature, since the IPCC estimates that the global average temperature has already increased one degree Celsius due to global warming.

An aggregation of demand parameters and relationships across all or part of the states within the electric grid provide an approximation of the demand-side for a US power system. Data transformations in the demand module include:

Relative prices influencing consumer behavior—consumer decisions regarding electric end use purchases involve price expectations. Price expectations typically reflect more than current prices and tend to reflect recent price experiences. Therefore, average electricity prices are converted to real prices and averaged over the past 5 years to approximate the price expectations influencing consumer economic decision making.

Household budget constraints—income levels drive economic decisions and median household incomes expressed in base year dollars and adjusted for state cost of living differences to reflect the typical household budget constraint.

Efficiency program investment spending-- ratepayer-funded efficiency programs provide incentives to consumers to deploy greater amounts of capital in electric end uses (light bulbs, appliances…) in exchange for greater efficiency—producing electric services with less electric energy inputs. However, higher electric end use efficiency involves a trade-off between higher and certain upfront costs and lower uncertain future operating costs. Therefore, the cost of the greater efficiency is the consumption of the additional capital over the operating life of the technology based upon an investment decision being made under uncertainty.

Electric end use technologies operating lives typically span 10 to 15 years. [i] However, considerable variation exists in expected operating lives and thus the expected end use capital consumption patterns. A useful aggregate approximation involves a non-linear capital consumption rate that is smaller in the initial years and then accelerates in later years before tailing off at the end. Therefore, analyses of ratepayer-funded efficiency program investments employed the following 10 year, non-linear, back end loaded depreciation schedule shown in Table 4.

TABLE 4

	Annual depreciation rate
Year 1	1.50%
Year 2	2.48%
Year 3	4.11%
Year 4	6.80%
Year 5	11.25%
Year 6	18.61%
Year 7	30.79%
Year 8	14.47%
Year 9	6.80%
Year 10	3.20%

Total	100.00%

Annual expenditures in ratepayer-funded efficiency are treated as an investment with annual investment costs rather than simply a current cost in the expenditure year. Applying these depreciation schedules to the ratepayer-funded efficiency spending across the past 10 years provides the basis to estimate the current accumulated net investment in ratepayer funded efficiency programs. In addition, this depreciation schedules indicate the impact of a single year of ratepayer-funded efficiency program spending across future years. Therefore, the full impact equals the cumulative total of the ratio of net plant to gross plant and in this case, an additional dollar of investment in ratepayer-funded efficiency programs produces an impact 6.3 times greater over the life of the investment than the impact expected in the first year alone.

US electric energy demand analyses

Quantification of US electric energy demand involves analysis of cross sectional state-level data (50 states plus DC) for each consumer sector (residential, commercial, and industrial) in 2014.

Residential consumer electric energy demand

The specification of the residential consumer electric energy demand function is shown in Equation 1.

Equation 1

$$Y_i = \beta_0 + \beta_1 X_{1i} + \beta_2 X_{2i} + \beta_3 X_{3i} + \beta_4 X_{4i} + e_i$$

Where:

i is the state and the DC.

Y_i is the natural log of the 2014 annual electricity consumption per residential customer (KWh/customer).

β_0 is the intercept.

β_1 is the estimate of the long-run price elasticity of energy demand.

X_1 is the natural log of a five-year lagging average real price of electricity ($2014 cents/KWh).

B_2 is the estimate of the long-run income elasticity of energy demand.

X_2 is the natural log of the median household income ($2014) adjusted by state cost of living index

B_3 is the estimate of the temperature elasticity of energy demand.

X_3 is the natural log of the population weighted average temperature (degrees Fahrenheit).

B_4 is the estimate of the net investment in ratepayer-funded efficiency programs elasticity of energy demand.

X_4 is the natural log of the lagging ten year accumulated net investment in ratepayer funded efficiency programs per non-industrial customer ($2014/customer).

e is the error term.

Residential Regression results

Since all variables are expressed as natural logs, the regression coefficients can be interpreted directly as elasticities of demand. Since price and income differences among states are longstanding, the x-sectional approach provides estimates of long-run elasticities. In addition, since the state of technology changes through time, the x-sectional approach also holds the state of technology constant because it analyzes the variance in residential electric energy demand across states in a single year—an interval approximating a constant state of technology.

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.893994449
R Square	0.799226074
Adjusted R Square	0.781767472
Standard Error	0.1280528
Observations	51

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	4	3.002605812	0.750651453	45.77835404	1.77693E-15
Residual	46	0.754285897	0.01639752		
Total	50	3.756891709			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	7.620722512	2.53741701	3.003338625	0.004308774	2.513166981	12.72827804
LN(5-year price)	-0.71581224	0.07927539	-9.029438272	9.43334E-12	-0.875385323	-0.556239156
ln(median hh income ppp)	0.114326268	0.216121596	0.528990487	0.599355539	-0.320703941	0.549356477
ln avg temp	0.625971103	0.116847054	5.35718345	2.62763E-06	0.390770182	0.861172023
LN(EE spending 10-year per cust)	-0.055820828	0.013379153	-4.172224295	0.000132356	-0.082751667	-0.02888999

The adjusted R-Square statistic indicates that the four independent variables and the constant term forming the estimated equation altogether explain a high proportion (78%) of the observed variation among the states in residential electric energy consumption. The F-statistic indicates that the estimated equation provides statistically significant explanatory power because the probability that no relationship exists between the dependent variable and the independent variables is less than 1 percent. The Multiple-R statistic indicates a high degree of correlation between the dependent variables actual values and the values predicted by back casting the estimated equation for the base year.

The signs and magnitudes of all the regression coefficients conform to expectations:

Price--rational utility maximizing consumers subject to a budget constraint produce a downward sloping aggregate demand curve and thus, create the expectation of a negative price elasticity of demand. The estimated long-run price elasticity of demand is negative and falls within the range defined by other studies. An analysis of 36 studies published between 1971 and 2000 yielded 125 estimates of the long-run residential price elasticity of demand and found estimates ranging from -0.04 to -2.25 with a mean of -0.85 and a median of -0.81. [74]

The estimated price coefficient is statistically significant based on conventional metrics. The null hypothesis is that no relationship exists with the dependent variable because the true value of the coefficient is zero. The T-statistic indicates that the probability of a type I error –rejecting this null hypothesis when it is true--is less than 1 percent.

Income--rational utility maximizing consumers produce a positive sloping aggregate Engel Curve for a normal good or commodity and thus, create the expectation of a positive income elasticity of demand. In addition, since the US is a developed economy, the expectation is that the income elasticity will be in the inelastic range.

[74] James A. Espy and Molly Espy, *Turning on the Lights: A Meta-Analysis of Residential Electricity Demand Elasticities*, Journal of Agricultural and Applied Economics, Vol. 36, No. 1, 2004.

The estimated income elasticity of demand is positive and inelastic. The null hypothesis is that no relationship exists with the dependent variable because the true value of the coefficient is zero. The T-statistic does not allow rejection of the null hypothesis based on conventional metrics employing a 5 percent or less probability of a type I error (rejecting this null hypothesis when it is true). As the upper and lower 95% probability range of the coefficient estimate indicate, there is about a 30 percent probability that the true value of the coefficient is less than or equal to zero. A priori expectations of the relationship between household income and residential electric consumption lead to the conclusion a specification retaining the income variable and coefficient is preferable to dropping them from the estimated demand equation.

Average temperature--electricity demand is linked to heating and cooling requirements and in the US, the seasonal cooling impacts are more powerful than seasonal heating impacts. As a result, the expectation is for a positive coefficient on the average temperature variable.

The estimated coefficient is positive and statistically significant based on conventional metrics. The null hypothesis is that no relationship exists with the dependent variable because the true value of the coefficient is zero. The T-statistic indicates that the probability of a type I error (rejecting this null hypothesis when it is true) is less than 1 percent.

Net investment in ratepayer-funded efficiency programs—initiatives to increase efficiency investments beyond what consumers choose to do otherwise result in lower electric energy consumption. As a result, the estimated coefficient is expected to be negative.

The estimated coefficient is negative and statistically significant based on conventional metrics. The null hypothesis is that no relationship exists with the dependent variable because the true value of the coefficient is zero. The T-statistic indicates that the probability of a type I error (rejecting this null hypothesis when it is true) is less than 1 percent.

Commercial consumer electric energy demand

The specification of the commercial consumer electric energy demand function is shown in Equation 2.

Equation 2

$$Y_i = \beta_0 + \beta_1 X_{1i} + \beta_2 X_{2i} + \beta_3 X_{3i} + \beta_4 X_{4i} + e_i$$

Where:

i is the state and the DC.

β_0 is the intercept.

Y_i is the natural log of the 2014 annual electricity consumption per commercial customer (MWh/customer).

β_1 is the estimate of the long-run price elasticity of energy demand.

X_1 is the natural log of the five-year lagging average real price of electricity ($2014 cents/KWh).

B_2 is the estimate of the long-run production elasticity of energy demand.

X_2 is the natural log of the gross domestic product per commercial consumer by state (2014$/customer).

B_3 is the estimate of the temperature elasticity of energy demand.

X_3 is the natural log of the population weighted average temperature (degrees Fahrenheit).

B_4 is the estimate of the net investment in ratepayer-funded efficiency programs elasticity of energy demand.

X_4 is the natural log of the lagging ten year accumulated net investment in ratepayer funded efficiency programs per non-industrial customer ($2014/customer).

e is the error term.

Commercial regression results

Since all variables are expressed as natural logs, the regression coefficients can be interpreted directly as elasticities of demand. Since differences in electric prices among states are longstanding, the x-sectional approach provides estimates of long-run elasticities. In addition, since the state of technology changes through time, the x-sectional approach also holds the state of technology constant because it analyzes the variance in commercial electric energy demand across states in a single year.

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.912267316
R Square	0.832231656
Adjusted R Square	0.817643104
Standard Error	0.132847813
Observations	51

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	4	4.027178377	1.006794594	57.04690059	2.96769E-17
Residual	46	0.81183291	0.017648542		
Total	50	4.839011287			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	-6.362496117	0.786230961	-8.092400875	2.16205E-10	-7.94509696	-4.779895276
LN 5 yr price	-0.501549627	0.076892586	-6.522730677	4.74891E-08	-0.65632637	-0.34677288
LN(State GDP per com cust)	0.743840483	0.052266843	14.23159376	1.81969E-18	0.638632784	0.849048183
ln avg temp	0.463083141	0.108195294	4.280067319	9.37886E-05	0.24529731	0.680868972
LN(EE spending 10-year per R8	-0.037255632	0.013877971	-2.684515727	0.010064634	-0.06519054	-0.009320725

The adjusted R-Square statistic indicates that altogether the three independent variables and the constant term in the estimated equation explain a high proportion (82%) of the observed variation among the states in commercial electric energy consumption. The F-statistic indicates that the estimated equation has statistically significant explanatory power because the probability that no relationship exists between the dependent variable and the independent variables is less than 1 percent. The Multiple-R statistic indicates a high degree of correlation between the dependent variables actual values and the predicted values from the estimated equation.

The signs and magnitudes of all the regression coefficients conform to expectations:

Price--a rational profit maximizing commercial firm produces a downward sloping derived demand curve for electric energy and thus, creates the expectation of a negative price elasticity of demand.

The estimated long-run price elasticity of demand is negative. The estimated coefficient is statistically significant based on conventional metrics. The null hypothesis is that no relationship exists with the dependent variable because the true value of the coefficient is zero. The T-statistic indicates that the probability of a type I error (rejecting this null hypothesis when it is true) is less than 1 percent.

Gross state product per customer--electricity is an input into most production functions in the economy. Therefore, an expectation exists for a positive coefficient.

The estimated coefficient is positive and statistically significant based on conventional metrics. The null hypothesis is that no relationship exists with the dependent variable because the true value of the coefficient is zero. The T-statistic indicates that the probability of a type I error (rejecting this null hypothesis when it is true) is less than 1 percent.

Average temperature--electricity demand is linked to heating and cooling requirements and in the US, the seasonal cooling impacts are more powerful than seasonal heating impacts. As a result, the expectation is for a positive coefficient on average temperature variable.

The estimated coefficient is positive and statistically significant based on conventional metrics. The null hypothesis is that no relationship exists with the dependent variable because the true value of the coefficient is zero. The T-statistic indicates that the probability of a type I error (rejecting this null hypothesis when it is true) is less than 1 percent.

Net investment in ratepayer-funded efficiency programs—initiatives to increase efficiency investments beyond what consumers choose to do otherwise result in lower electric energy consumption. As a result, the estimated coefficient is expected to be negative.

The estimated coefficient is negative and statistically significant based on conventional metrics. The null hypothesis is that no relationship exists with the dependent variable because the true value of the coefficient is zero. The T-statistic indicates that the probability of a type I error (rejecting this null hypothesis when it is true) is less than 1 percent.

Industrial consumer electric energy demand

The industrial consumer electric energy demand function is shown in Equation 3.

Equation 3

$$\mathbf{Y}_{i} = \boldsymbol{\beta}_{0} + \boldsymbol{\beta}_{1}\mathbf{X}_{1i} + \boldsymbol{\beta}_{2}\mathbf{X}_{2i} + e_{i}$$

Where:

i is the state and the DC.

β_0 is the intercept.

Y_i is the natural log of the 2014 annual electricity consumption (MWh).

β_1 is the estimate of the long-run price elasticity of energy demand.

X_1 is the natural log of the trailing 5-year average real price of electricity ($2014 cents/KWh).

B_2 is the estimate of the long-run production elasticity of energy demand.

X_2 is the natural log of the gross state product (millions $2014).

e is the error term.

Industrial regression results

Since all variables are expressed as natural logs, the regression coefficients can be interpreted directly as elasticities of demand. Since differences in electric prices among states are longstanding, the x-sectional approach provides estimates of long-run elasticities. In addition, since the state of technology changes through time, the x-sectional approach also holds the state of technology constant because it analyzes the variance in commercial electric energy demand across states in a single year.

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.79235173
R Square	0.627821264
Adjusted R Square	0.612313817
Standard Error	0.745614116
Observations	51

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	45.01465697	22.50732848	40.48514566	4.98927E-11
Residual	48	26.68513968	0.55594041		
Total	50	71.69979665			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.091209421	2.820686164	0.032335898	0.974338269	-5.580160221	5.762579062
ln 5yr price	-1.496288156	0.317495819	-4.712780656	2.1282E-05	-2.134656286	-0.857920026
ln GDP	0.738646324	0.103125489	7.162597056	4.14372E-09	0.531298632	0.945994017

The adjusted R-Square statistic indicates that altogether the two independent variables and the constant term in the estimated equation explain a high proportion (61%) of the observed variation among the states in industrial electric energy consumption. The F-statistic indicates that the estimated equation provides statistically significant explanatory power because the probability that no relationship exists between the dependent variable and the independent variables is less than 1 percent. The Multiple-R statistic indicates a high degree of correlation between the dependent variables actual values and the predicted values from the estimated equation.

The signs and magnitudes of all the regression coefficients conform to expectations:

Price--a rational profit maximizing industrial firm produces a downward sloping derived demand curve for electric energy and thus, creates the expectation of a negative price elasticity of demand.

The estimated long-run price elasticity of demand is negative. The magnitude of the coefficient aligns with previous research. A survey of the literature for the US Department of Energy by Carol Dahl in 1993 found a wide disparity in estimates for both commercial and industrial price elasticities, ranging from a -1.03 to -1.94. The estimated coefficient is statistically significant based on conventional metrics. The null hypothesis is that no relationship exists with the dependent variable because the true value of the coefficient is zero. The T-statistic indicates that the probability of a type I error (rejecting this null hypothesis when it is true) is less than 1 percent.

Gross state product per customer-- electricity is an input into most production functions in the economy. Therefore, an expectation exists for a positive coefficient.

The estimated coefficient is positive and statistically significant based on conventional metrics. The null hypothesis is that no relationship exists with the dependent variable because the true value of the coefficient is zero. The T-statistic indicates that the probability of a type I error (rejecting this null hypothesis when it is true) is less than 1 percent.

The industrial consumer electric energy demand equation specification excludes a net investment in ratepayer-funded efficiency programs because these programs are focused primarily on the non-industrial consumer segments. The specification also does not include population weighted average temperature as an independent variable because space conditioning is not a major electric end use in the industrial sector.

Backcasting and counterfactuals

Estimated demand equations provide the capability to backcast—calculate predicted values of observed dependent variables by incorporating the actual values of the dependent variables into the estimated equations.

The functional form of the demand equation underlying the estimated equation for residential electric energy consumption is shown in Equation 4.

Equation 4

$$\mathbf{Y_i = e^{\beta_0} * X_{1\,i}{}^{\beta_1} * X_{2i}{}^{\beta_2} * X_{3i}{}^{\beta_3} * X_{4i}{}^{\beta_4}}$$

Where:

i is the state and the DC.

Y_i is the predicted value of the 2014 annual electricity consumption per residential customer (KWh/customer).

e is the mathematical constant base of natural logarithms.

β_0 is the estimated intercept value.

X_1 is the five-year lagging average real price of electricity ($2014 cents/KWh).

β_1 is the estimated long-run price elasticity of energy demand.

X_2 is the median household income ($2014).

B_2 is the estimated long-run income elasticity of energy demand.

X_3 is the population weighted average temperature (degrees Fahrenheit).

B_3 is the estimated temperature elasticity of energy demand.

X_4 is the lagging ten year accumulated net investment in ratepayer funded efficiency programs per non-industrial customer ($2014/customer).

B_4 is the estimated net investment in ratepayer-funded efficiency programs elasticity of energy demand.

The functional form of the demand equation underlying the estimated equation for commercial electric energy consumption is shown in Equation 5.

Equation 5

$$\mathbf{Y_i = e^{\beta_0} * X_{1\,i}{}^{\beta_1} * X_{2i}{}^{\beta_2} * X_{3i}{}^{\beta_3} * X_{4i}{}^{\beta_4}}$$

Where:

i is the state and the DC

Y_i is the predicted 2014 annual electricity consumption per commercial customer (KWh/customer).

e is the mathematical constant base of natural logarithms.

β_0 is the estimated intercept.

X_1 is the five-year lagging average real price of electricity ($2014 cents/KWh).

β_1 is the estimated long-run price elasticity of energy demand.

X_2 is the gross domestic product per commercial consumer by state (millions 2014$/customer).

B_2 is the estimated long-run production elasticity of energy demand.

X_3 is the population weighted average temperature (degrees Fahrenheit).

B_3 is the estimated temperature elasticity of energy demand.

X_4 is the lagging ten year accumulated net investment in ratepayer funded efficiency programs per non-industrial customer ($2014/customer).

B_4 is the estimated net investment in ratepayer-funded efficiency programs elasticity of energy demand.

The functional form of the demand equation underlying the estimated equation for commercial electric energy consumption is shown in Equation 6.

Equation 6

$$\mathbf{Y_i = e^{\beta_0} * X_{1\,i}{}^{\beta_1} * X_{2i}{}^{\beta_2}}$$

Where:

i is the state and the DC

Y_i is the predicted 2014 annual electricity consumption per industrial customer (KWh/customer)

e is the mathematical constant base of natural logarithms.

β_0 is the estimated intercept.

X_1 is the trailing 5-year average real price of electricity ($2014 cents/KWh).

β_1 is the estimated long-run price elasticity of energy demand.

X_2 is the gross state product per industrial customer (millions 2014$/customer).

B_2 is the estimated long-run production elasticity of energy demand.

The cost of increasing electric energy consumption efficiency

Relationships quantified in the demand analyses and the associated back casting capabilities allow estimation of the cost curve for increasing electric consumption efficiency beyond, what consumers choose to do themselves, through investments in ratepayer-funded programs. Constructing the cost curve for increasing electric energy efficiency beyond what consumers choose to do themselves through ratepayer-funded efficiency program investments involves six steps.

The first step involves isolating the impacts of existing levels of net investment in ratepayer-funded efficiency programs. Quantification is possible by employing comparative statics derived from the demand equations for the residential and commercial sectors. The base year impact equals the difference in predicted values for base year energy consumption with and without the actual net investment per customer in ratepayer-funded efficiency programs. This counterfactual result provides the starting point for constructing the cost curve for increasing electric energy consumption efficiency.

The second step involves estimating the percentage reduction in electric energy consumption in the first year of capital deployment associated with varying levels of net investment in ratepayer-funded efficiency programs. This step involves resolving the residential and commercial electric demand equations with increasing levels of net investment in ratepayer-funded efficiency programs. The associated declines in electric energy consumption--while holding all else constant--map out the expected positive relationship between net investment levels and electric consumption declines underlying the cost curve for increasing electric consumption efficiency.

The third step involves calculating the energy reductions beyond just the first year of capital deployment. This step is necessary because the regression coefficients on net investment in ratepayer-funded efficiency programs produces an estimate of the electric energy consumption impact in the first year, and not the full impact across the life of the investment.

The fourth step involves calculating the annual cost of different levels of net investment in ratepayer-funded efficiency programs in both the residential and commercial sectors. These costs involve the cost of capital consumed in the efficiency program, the opportunity cost of the capital employed, and the consumer contribution to total costs.

The cost of capital consumed in each year to produce the efficiency impact reflects the gross investment times the depreciation rate. Since a profitable investment recovers the upfront capital deployed, this "return of capital" cost provides recovery of the gross investment over the operating life of the efficiency investment. Since the depreciation rate employed in the ratepayer-funded investment case is non-linear, the return of capital cost is also uneven from one year to the next.

The opportunity cost of capital involves the foregone returns of deploying capital in the efficiency investment rather than the next best alternative use. This opportunity cost is referred to as the "return on capital" deployed and equals the net plant value (gross investment less accumulated depreciation) multiplied by the consumers cost of capital. Since net plant value declines over the operating life of the end use technology, this annual cost component also declines through time.

Ratepayer-funded efficiency programs provide subsidies to consumers as an incentive to alter consumer decisions in favor of deploying higher upfront cost, but more electric efficient end use technologies. Analyses of ratepayer-funded efficiency programs indicate that subsidies typically cover 50 percent of the efficiency investment.[75] Therefore, the full cost of an efficient investment involves the addition of the consumer contribution.

The fifth step involves calculating the "deadweight loss" to residential consumers arising from the imposition of a ratepayer funded efficiency charge. The estimated residential demand curve provides a schedule of the consumer's willingness to pay for different amounts of electric energy. Since the demand curve arise from residential consumers maximizing utility, the demand curve involves a consumer surplus measuring how much less residential consumers pay for electric energy than the value they put on that level of consumption. The existence of consumer surplus explains why consumers get mad when there is a blackout, even though this electric service interruption creates a proportional decline in their power bill.

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[75] K. Friedrich, M. Eldridge, D. York, P. Witte, and M. Kushler, *Saving Energy Cost Effectively: A National Review of the Cost of Energy Saved through Utility-Sector Energy Efficiency Programs,* American Council for an Energy-Efficient Economy, September 2009. http://www.dnrec.delaware.gov/energy/information/Documents/EERS/Review%20of%20Cost%20Effective%20Energy%20Savings.pdf

Consumers incur a deadweight cost even when the funds collected by a ratepayer-funded efficiency are fully recycled back to consumers in the form of electric efficiency subsidies. When a CO_2 charge is internalized into the residential electricity price, then households balance the value of consuming more electricity against the value of consuming other goods and services instead and the consumption choices consumers make reveal the bundle of goods and services that they value the most. Consumers revealed their preferences when they choose to allocate scarce capital resources to investments other than efficiency investments in the absence of subsidies and these decisions reveal their preferences for investing in options with better expected risk adjusted returns compared to the unsubsidized efficiency investment opportunities. A ratepayer-funded efficiency program imposes a charge to fund the efficiency program designed to alter the relative prices of goods and services to move a consumer away from their preferred consumption mix of goods and services. A deadweight cost arises even when purchasing power is maintained because the consumer ends up in a less preferred consumption position involving expenditures on electric energy efficiency beyond what they would otherwise choose to do. Deadweight loss measures the loss in value in moving from the initial preferred bundle of goods and services to the bundle chosen with relative prices altered by subsidies paid for by the imposed and recycled consumer charge.

Equation 7 provides an approximation of the cost of the deadweight loss.[76]

Equation 7

$$\mathbf{DWL = (Y_i - Y_{i0}) * (X_i - Y_{i0}) * 0.5}$$

Where:

DWL is the deadweight loss.

Y_i is the predicted value of the 2014 annual electricity consumption per residential customer (KWh/customer).

Y_{i0} is the predicted value of the 2014 annual electricity consumption per residential customer (KWh/customer) with a zero-net investment in ratepayer-funded efficiency programs with all else constant.

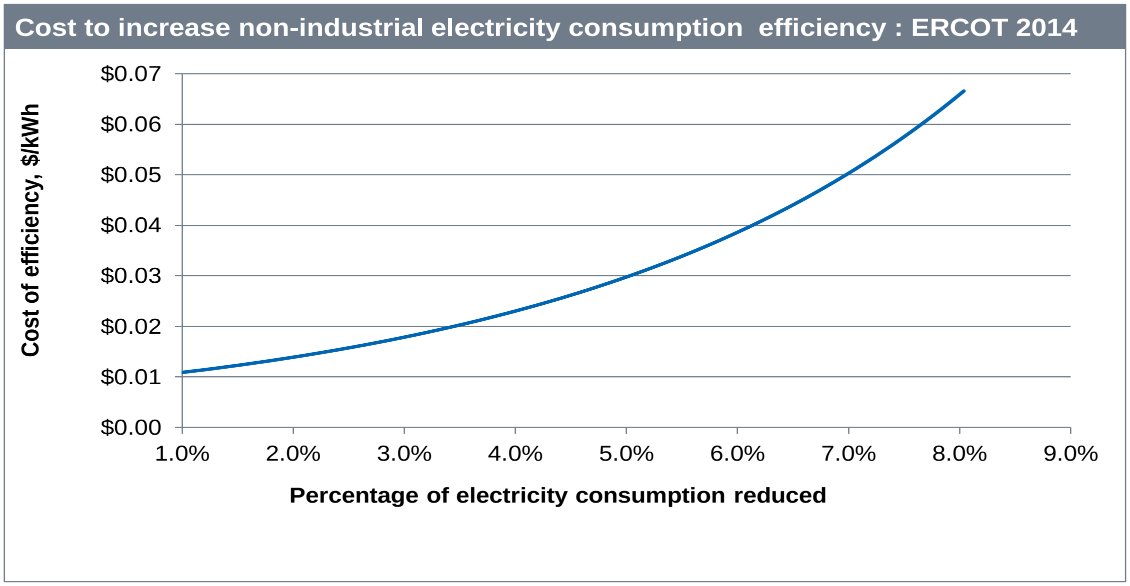
X_1 is the five-year lagging average real price of electricity ($2014 cents/KWh) including the ratepayer-funded efficiency charge.

X_{10} is the five-year lagging average real price of electricity ($2014 cents/KWh) less the ratepayer-funded efficiency charge.

The sixth step involves expressing the uneven stream of costs per KWh reduced over the investment operating lifetime as a levelized annual unit cost stream. The sum of the uneven annual cost components of ratepayer-funded efficiency programs are the numerator and the sum of the uneven annual electric energy reductions are the denominator. The construction of the cost curve involves finding the constant annual cost per KWH over the life of the investment that has an equivalent present value to the estimated uneven cost per KWh. Figure 38 provides an example of applying this methodology to estimate the ERCOT ratepayer-funded efficiency program electric energy reduction cost curve for 2014.

[76] P. Krugman and R. Wells, Microeconomics, Worth Publishers, 2005, pp 152-155.

FIGURE 38



Estimates of net impacts of electric end use technology changes and rebound effects

The cross-sectional regressions for the residential, commercial and industrial sectors hold technology and consumer behavior constant in the year 2014. Since the E-PATH demand equations are not missing any variables, deploying these equations to backcast electric energy demand provides the opportunity to solve through time for the one unknown variable that changed through time, which is the net effect of electric consumption end use technology changes and consumer behavioral trends. For example, the technological advances in electronic computing created an increase in electric consumption through time due to the expanded penetration of personal computers, smart phones and associated big data infrastructure. This creates a positive impact on electric use. Similarly, the efficiency gains embodied in the 2014 end use stock of electric appliances created a rebound effect through time, as for example, when refrigerators became more efficient, consumers purchased bigger refrigerators and substituted fresh food purchases for canned food purchases and created a positive "rebound" effect from a gain in electric end use efficiency. Solving for this demand determinant provides a basis for setting the trend in this exogenous demand side factor affecting future electric consumption levels.

Dispatchable supply LCOE screening curve module

Matching electric generation to varying load in real time is a defining requirement of the cost minimization algorithm of the E-PATH. To meet this requirement involves always having enough dependable electric capability available to meet the maximum instantaneous net load, as well as having enough flexible generating capacity to follow changes in net load through time. These constraints exist because economic electricity inventory options do not eliminate the variations in net electric load through time.

Efficient power system operation involves generating electric energy to match power system electric net-load in real time subject to security and environmental constraints. To meet this operational requirement, conventional power generation technologies evolved with the operational capability to vary output with enough flexibility to follow expected changes in system net load requirements through time. As a result, conventional generation technologies have varying degrees of "dispatchability."

Conventional dispatchable electricity production at efficient scale involves capital intensive production technologies with multi-year economic lives. Thus, meeting the electric system objective requires a cost-effective alignment of these long lived dispatchable electric service supply technologies to the recurring short-run annual pattern of electric system net load. Since the economic life of dispatchable generating technologies exceeds the time dimension of hourly demand and supply equilibration, the upfront capital costs need to be treated as a fixed cost—a cost that is invariant to the annual utilization rate of the generating technology.

E-PATH employs a long-standing approach to finding the mix of physical plant and the associated varied utilization rates in a supply portfolio that produces a commodity with time varied demand levels at minimum cost with uneconomic inventory options.[77] This approach requires quantifying the changes in the levelized cost of energy associated with changes in utilization rates. These alternative generating resource cost screening curves include both capital and variable cost components.

Two capital cost components arise from deploying capital in electric generating technologies. First, the annual cost associated with capital consumed over the life of the generation technology. Second, the annual opportunity cost associated with having capital deployed in the productive process. The sum of these two components—the return of capital and the return on capital—produce an annual fixed capital cost.

Return of capital cost

The initial amount of capital employed is calculated as the gross plant value:

$GP_t = KW_t * IC_t$

Where:

t = technology

n = year of operation (n=1 in first year of operation)

GP_t = Gross Plant Value (dollars)

KW_t = Installed capacity (kilowatts)

IC_t = installed cost per kilowatt ($/KW)

Depreciation costs approximate the annual consumption of capital in the production process through time. Depreciation costs are:

$BOOKDEP_{tn} = GP_t / N_t$

Where:

t = technology

[77] Williamson O E, "Peak Load Pricing and Optimal Capacity under Indivisibility Constraints" AER, vol. 56 no 4, September 1966, pp 810-827

n = year of operation (n=1 in first year of operation)

GP_t= gross plant value (dollars)

$BOOKDEP_{tn}$= book depreciation (dollars)

N_t= operating life

The annual consumption of capital over the operating life of a generating plant causes the amount of capital deployed to also decline over the life of a generating plant. Accumulated depreciation measures this cumulative consumption of capital and is calculated as:

$$ACCBKDEP_{tn} = ACCBKDEP_{tn-1} + BOOKDEP_{tn}$$

Where:

t = technology

n = year of operation (n=1 in first year of operation)

$ACCBKDEP_{tn}$= accumulated book depreciation, initialized to zero in the year prior to operation (n=0), (dollars)

$BOOKDEP_{tn}$= book depreciation (dollars)

Return on capital cost

The costs of capital deployed reflect the opportunity cost of capital. Interest costs approximate the cost for borrowed capital and the competitive rate of return on equity approximates the cost of equity capital. The difference in interest rate and the competitive rate of return on capital reflects the difference risks of capital cost recovery. The return to debt capital is the interest expense that is calculated as follows:

$$INT_{tn} = (GP_t - ACCBKDEP_{tn}) \times CS_d \times INTR_n$$

Where:

t = technology

n = year of operation (n=1 in first year of operation)

INT_{tn}= interest expense (dollars)

GP_t= gross plant value (dollars)

$ACCBKDEP_{tn}$= accumulated book depreciation (dollars)

CS_d= debt percentage of capital structure

INTR = interest rate on borrowed funds

The annual cost of equity capital is calculated as:

$$ROE_{tn} = (GP_t - ACCBKDEP_{tn}) \times CS_e \times ROER_n$$

Where:

t = technology

n = year of operation (n=1 in first year of operation)

ROE_{tn}= after tax return on equity (dollars)

GP_t= gross plant value (dollars)

$ACCBKDEP_{tn}$= accumulated book depreciation (dollars)

CS_e= equity percent of capital structure

ROER = market after tax return on equity rate

Annual fixed costs

Since capital is a fixed input to the annual production process, capital costs are considered part of annual fixed costs. Similarly, some operation and maintenance costs do not vary with annual output and are also considered fixed costs. Total annual fixed costs are the sum of the return of capital, and the return on capital, as well as fixed operation and maintenance expenses:

$$AFC_{tn} = BOOKDEP_{tn} + INT_{tn} + ROE_{tn} + (FO\&M_{tn} \times KW_t)$$

Where:

t = technology

n = year of operation (n=1 in first year of operation)

AFC_{tn}= total annual fixed costs (dollars)

$BOOKDEP_{tn}$= Book depreciation (dollars)

INT_{tn}= interest expense (dollars)

ROE_{tn}= after tax return on equity (dollars)

KW_t= capacity

$FO\&M_{tn}$= Fixed operations and maintenance expenses ($/KW)

Income Tax Expense

Income taxes are calculated as using the tax compliment as follows:

$$INCTX_{tn} = ROE_{tn} \times \left(\left(\frac{1}{1 - INCTXR}\right) - 1\right)$$

Where:

$INCTX_{tn}$= income tax expense

ROE_{tn}= After tax return on equity

INCTXR = Income tax rate

Property Tax and Insurance

Property taxes and Insurance are based on net book value and calculated as:

$$PTXI_{tn} = (GP_t - ACCBKDEP_{tn}) \times PTXIR$$

Where:

$PTXI_{tn}$= Property tax and insurance expenses

GP_t= gross plant value (dollars)

$ACCBKDEP_{tn}$= accumulated book depreciation (dollars)

PTXIR = Property tax and insurance rate

Deferred Taxes

Tax depreciation schedules provide a subsidy by allowing recognition of depreciation costs before they are incurred in the calculation of taxable income. Therefore, the difference between tax depreciation and book depreciation gives rise to deferred taxes. The book depreciation is adjusted for the difference between the book and tax gross plant basis. Deferred taxes are calculated as:

$$DEFTAX_{tn} = (TXDEP_{tn} - (\frac{GPTAX_t}{GP_t})BOOKDEP_{tn}) \times INCTXR$$

Where:

$DEFTAX_{tn}$= Deferred Taxes

$TXDEP_{tn}$= Tax depreciation

$GPTAX_t$= Tax Basis for Gross Plant Value (dollars)

GP_t= Gross Plant Value (dollars)

$BOOKDEP_{tn}$= Book depreciation in year n

INCTXR = Income tax rate

Income Taxes with deferred taxes

Income taxes incorporating the effects of deferred taxes are:

$$INCTX_{tn} = ROE_{tn} \times \left(\left(\frac{1}{1 - INCTXR}\right) - 1\right) - DEFTAX_{tn}$$

Where:

$INCTX_{tn}$= income tax expense with subsidy impacts

ROE_{tn}= After tax return on equity

INCTXR = Income tax rate

$DEFTAX_{tn}$= Deferred Taxes

Total Taxes

Total annual tax expense are the sum of income taxes and property and insurance expenses less deferred taxes, investment tax credits and production tax credits. This is calculated as:

$$TAXES_{tn} = INCTX_{tn} + PTXI_{tn}$$

Where:

$TAXES_{tn}$= Total annual tax expense

$INCTX_{tn}$= income tax expense

$PTXI_{tn}$= Property tax and insurance expenses

Variable Operating Costs

During the operation of a power plant, variable costs are related to the level of power output. There are three primary types of these variable costs: fuel, variable operating and maintenance (O&M), and emissions costs.

Fuel Costs

The total fuel cost per year depends on the price paid for delivered fuel, the amount of power produced, and the efficiency at which the power plant can convert the fossil fuel into power. The heat rate is a measure of the efficiency of the power plant in transforming the energy of the fuel input into electricity. The fuel costs are calculated as:

$$F_{t,n} = DF_{t,n} \times KWh_{t,n} \times HR_t \times (\frac{1}{1{,}000{,}000})$$

Where:

$F_{t,n} =$ Fuel cost

$DF_{t,n} =$ Delivered price of fuel for a given technology expressed in dollars per MMBtu

$KWh_{t,n} =$ Power plant output in kWh

$HR_t =$ Heat rate of the power plant technology, t, in btu per kWh

$(Dividing\ by\ 1{,}000{,}000\ converts\ btu\ per\ kWh\ to\ MMBtu\ per\ kWh.)$

Variable O&M Costs

The operations and maintenance costs vary depending on how often the power plant is operated and how much power is produced. The variable O&M costs are calculated as:

$$VOM_n = vom_{t,n} \times KWh_n(\frac{1}{1{,}000})$$

Where:

$VOM_n =$ Variable operations and maintenance costs in dollars duringa given year, n.

$vom_{t,n} =$ Variable operations and maintenance costs in dollars per MWh for a given technology, t, and a given year, n.

$KWh_{ny} =$ Power plant output in KWh in a given year, n.

$(Dividing\ by\ 1{,}000\ converts\ kWh\ to\ MWh\ of\ power\ output.)$

Environmental Costs

Environmental costs are internalized by:

$$E_{t,p,n} = EP_{t,p,n} \times EI_{t,p} \times (\frac{1}{2{,}204}) \times HR_t \times (\frac{1}{1{,}000{,}000}) \times KWh_y$$

Where:

$E_{t,p,y}$ = Emission costs in dollars for a given technology, t, for a given pollutant, p, for a given year, n.

$EP_{t,p}$ = Emissions price in dollars per metric ton of a given pollutant, p, for a given technology, t, for a given year, n.

$EI_{t,p}$ = Emissions intensity in pounds per MMBtu for a given pollutant, p, for a given technology, t.

$(Dividing\ by\ 2{,}204\ converts\ pounds\ into\ metric\ tons.)$

HR_t = Heat rate of the power plant in btu per kWh, for a given technology, t.

(Dividing by 1,000,000 converts Btu into MMBtu.)

KWh_{ny} = Power plant output in kWh in a given year, n.

Total Variable Costs

Total annual variable costs are:

$$AVC_{tn} = F_{t,n} + VOM_n + \sum_p E_{t,p,n}$$

Where:

AVC_{tn}= Total annual variable costs

$F_{t,n}$ = Fuel cost

VOM_n = Variable operations and maintenance costs in dollars duringa given year, n.

$E_{t,p,n}$ = Emission costs in dollars for a given technology, t

Annual Costs of Power Supply

The total annual cost of the dispatchable power technology supply is:

$TAC_{tn} = (AFC_{tn} + TAXES_{tn} + AVC_{tn}) / KWh_{tn}$

Where:

TAC_{tn}= Total annual power supply cost per KWh

AFC_{tn}= Total annual fixed costs

$TAXES_{tn}$= Total annual tax expense

AVC_{tn}= Total annual variable costs

$KWh_{t,n}$ = Annual power plant output in kWh

Levelized Annual Cost per KWh of Dispatchable Generating Technologies

The annual cost per KWh varies from one year to the next over the expected operating life of the generating technology. Levelization is a technique to find a constant annual cost per KWh that has the same present value over the life of the power plant. The levelized annual cost is:

$$PV(n \times LC) = \sum_{n} PV(TA\,C_n)$$

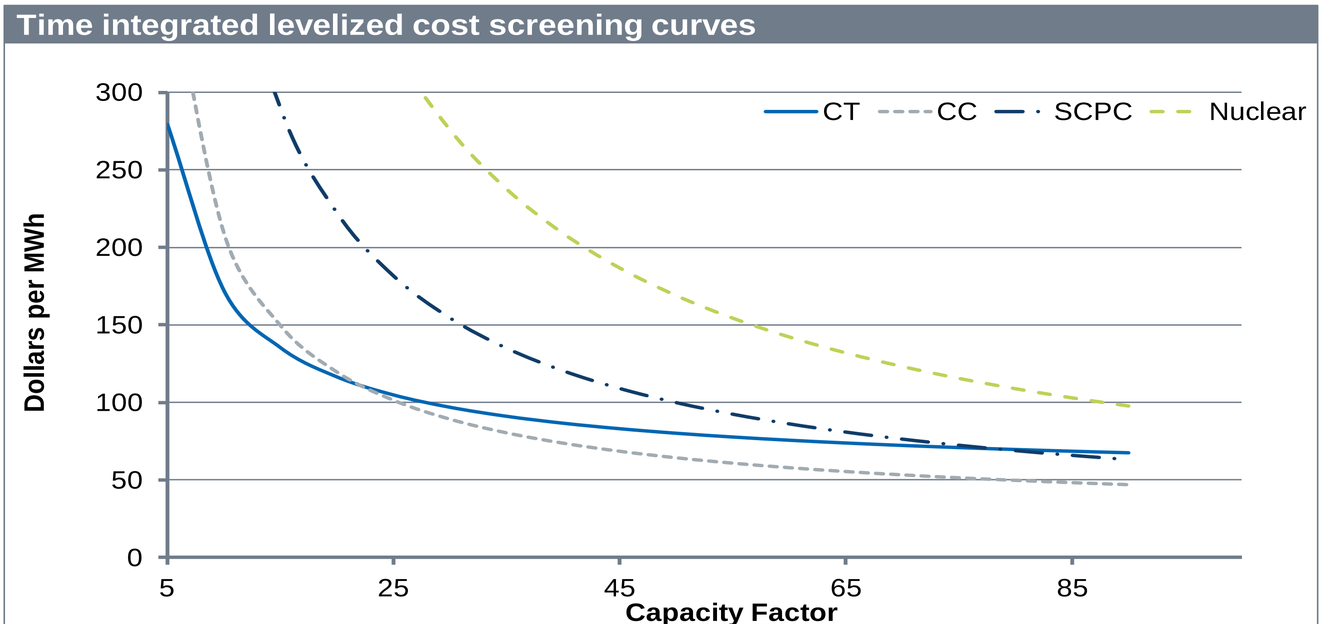
Where:

LC = Annual levelized cost per KWh

TAC_n= Total annual power supply cost per KWh

Dispatchable generating technology LCOE screening curves trace out a least-cost frontier versus expected utilization rates. For example, Figure 39 shows an example of four alternative new dispatchable electric generation technologies in which the combustion turbine generating technology is the lowest cost source of new supply for net load levels expected less than about 25 percent of the time, and the combined cycle generating technology is the lowest cost source of new power supply for net load levels expected 25 percent of the time or more.

FIGURE 39



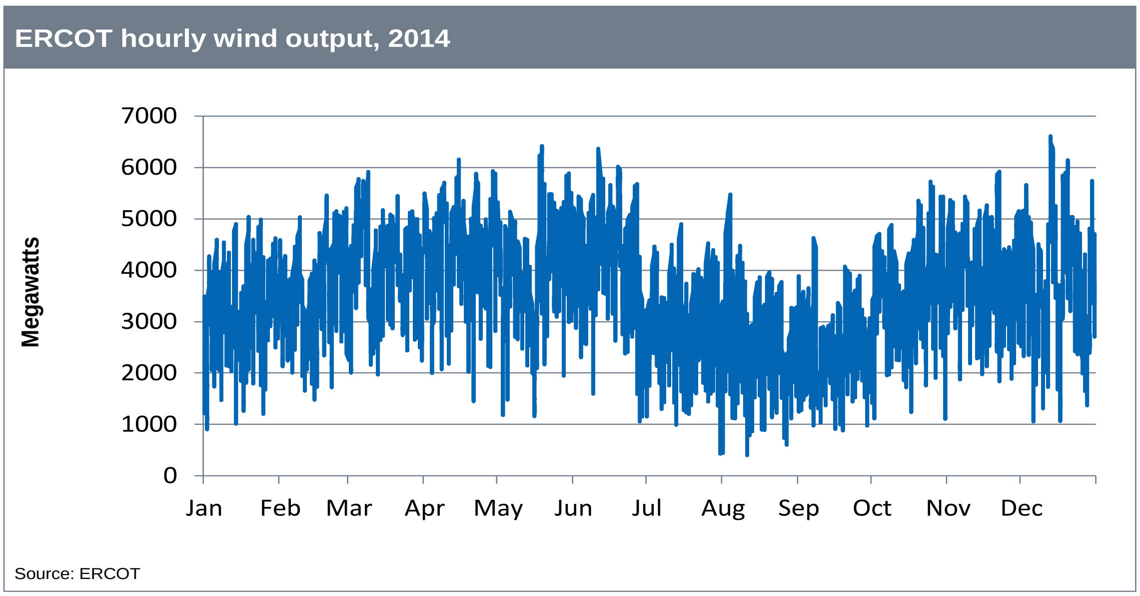
CT: conventional combustion turbine unit, CC: conventionial combined cycle unit, SCPC: super-critical pulverized coal unit

Screening curves show how production costs vary with utilization rates across technologies. This outcome arises because a variety of technologies can generate electric energy, and a fundamental tradeoff exists between the upfront capital costs and the efficiency of transforming primary energy inputs into electric energy. Since net load varies through time, cost effective alignment of power supply to net load in real time means that all power plants do not operate at the same utilization rate and power plants do not necessarily operate at their most efficient stand-alone utilization rate. This condition of a least-cost solution does not constitute underutilization or inefficiency in electric energy production. Instead it is the basis for finding the efficient power supply portfolio to meet a given net load profile. Consequently, the least-cost alignment of dispatchable resources to meet net load typically involves a mix of generating technologies.

Load modifier module

Load modifiers include ratepayer-funded efficiency program impacts, non-dispatchable power generation sources including wind, solar, and hydro outputs and storage impacts. Load modifiers have two characteristics. First, the costs are positive and increasing with the scale of deployment. Second, load modifier impacts alter the profile of net load through time. Figure 40 provides the example of the recent annual hourly pattern of wind production in ERCOT to illustrate the time pattern of a load modifier.

FIGURE 40



Electric storage can modify net load because charging and discharging electricity can smooth the hourly variation of power system load. Since the marginal cost of electric production is positively correlated to aggregate load, electric inventory becomes economic when the storage cost is less than the production cost reduction associated with smoothing the load profile.

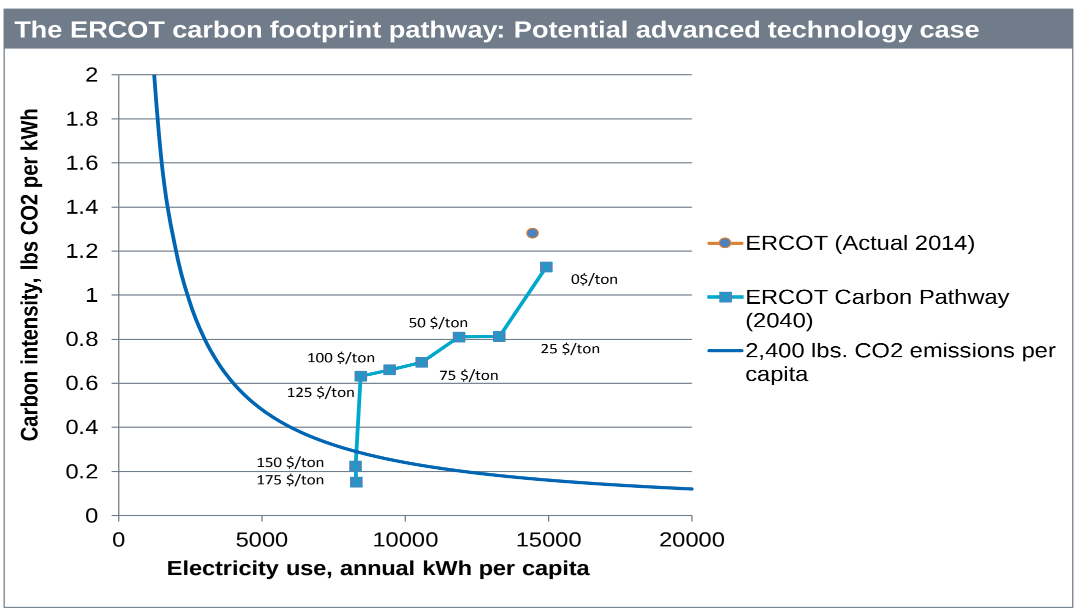
Mapping the least-cost CO_2 emission footprint reduction pathway

E-PATH employs an iterative solution algorithm to converge on a least-cost solution of dispatchable supply and load modifiers that meet security of supply requirements. Although the least-cost electric generation mix typically involves a mix of generating technologies and load modifiers, it does not typically include all possible demand and supply options. For example, electric generation technologies typically involve significant economies of scale and as a result, the current cost and performance of small distributed generation technologies are typically less cost effective than larger scale grid based power supply. As a result, an available small distributed technology may not be part of a least-cost solution.

A series of E-PATH solutions internalize incrementally higher CO_2 emission charges while holding all other inputs constant. This sequence of solutions with increasing CO_2 emission charges cause increases in marginal electricity production costs based on the carbon intensity of alternative electric generating resources, and consequently shifts the least-cost supply portfolio toward a mix of fuels and technologies with a lower CO_2 emission per kilowatt-hour profiles. On the demand side, higher marginal production costs drive electricity prices higher and cause electricity consumption per capita to decline due to consumer responses to price increases, as well as from higher levels of cost-effective ratepayer-funded efficiency programs. These reductions in both the demand and supply-side factors each cause a proportional reduction in the future electricity CO_2 emission footprint and thus, produce an inverse relationship between the level of the CO_2 emission charge and the electricity CO_2 emission footprint.

E-PATH solutions that internalize increasingly higher CO_2 emission charges alter the least-cost demand and supply coordinates for the power system electricity CO_2 emission footprint. These changed coordinates map out the least-cost pathway to lower future power system electricity CO_2 emission footprints from the baseline electricity CO_2 emission footprint. Figure 41 provides an example by illustrating the result of least-cost CO_2 emission footprint pathway analysis of the Texas power system for the year 2040. In this example, the baseline electricity CO_2 emission footprint is lower than the current CO_2 emission footprint (the "costless change in electricity CO_2 emission footprint") and increments of $25 per ton in the CO_2 emission charge produces sequential least-cost solutions with increasingly lower future year CO_2 emission footprints.

FIGURE 41

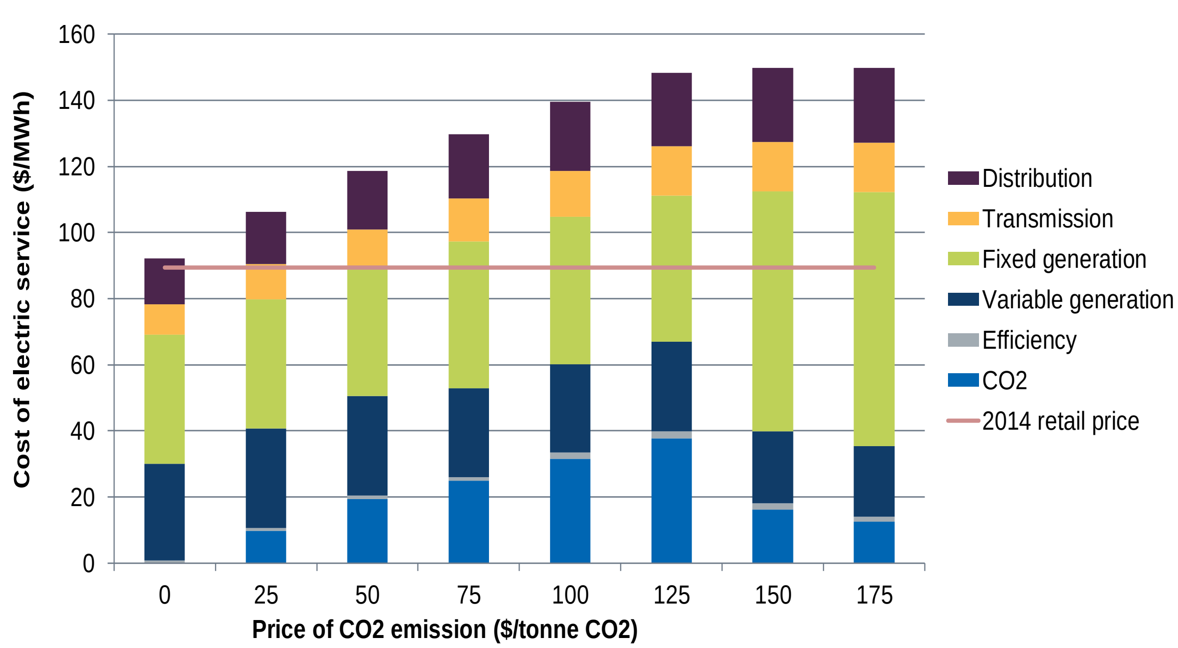


Power system CO_2 emission abatement costs

Electricity CO_2 emission footprint pathway analysis calculates average total cost-based retail electricity prices. Figure 42 shows the example of ERCOT with a breakdown of the cost components.

FIGURE 42

ERCOT 2040 cost of electric service cost under CO2 pricing: Potential advanced technology case



Chapter 5: The least-cost pathway to reducing future US electricity sector CO_2 emission footprints

The least-cost pathway to reducing future US electricity CO_2 emission footprints depends on the state of technology and the lead time for policy implementation. Costs are a function of the state of technology and the future state of technology is difficult to predict. Therefore, this assessment incorporates technological uncertainty by developing two pathways; the first pathway deploys the current best available state of technology while the second pathway employs a potential advanced state of technology. Both cases maximize available climate policy lead time by shifting away from business-as-usual climate policy initiatives and toward implementing CO_2 emission charge driven demand and supply alterations without delay.

The state of technology impacts climate policy implementation costs

The state of technology determines the cost to transform primary energy inputs into electricity outputs. Table 5 shows the variation in cost and performance characteristics of the current best available technologies capable of delivering AC power to the grid. The technologies are all utility scale power supply options. These profiles for new resources are consistent with the EIA Annual Energy Outlook and current cost and performance data.[78]

TABLE 5

Current best available technology cost and performance profiles

		Combustion Turbine	Combined Cycle	Supercritical Coal	Nuclear	Wind	Solar PV
Capital costs	$/Kw	1092	969	5030	5880	1686	2277
Life	years	25	25	40	60	20	20
Fixed O&M	$/Kw-year	17.39	10.93	60	99.65	46.71	21.66
Variable O&M	$/MWh	3.48	3.48	5	2.29	0	0
Fuel Cost	$/mmBtu	3.5	3.5	2	0.7	0	0
Heat Rate	Btu/KWh	14700	6828	8300	9800		
Firm Capacity	Nameplate %	93	90	88	90	10	45
Property tax and Insurance	Net plant %	1.25	1.25	1.25	1.25	0.7	1.5

[78] US Energy Information Administration, *Cost and Performance Characteristics of New Generating Technologies*, Annual Energy Outlook, 2017.

Legacy natural gas, coal and nuclear technologies involve fixed O&M going forward costs of 25, 60 and 210 $/KW-year respectively. The current best available battery storage technology involves a levelized annual cost of $233 per KW. All power supply technology costs reflect some common cost parameters including income taxes reflecting 35% and 5% rates respectively for Federal and state levies, a capital structure of 50% debt and 50% equity, and real costs of capital equal to 5 and 9 percent respectively for debt and equity.

The first E-PATH solution employs current best available technology cost and performance characteristics to establish a cost benchmark. This approach does not reflect an assumption that technology will not change over the analysis timeframe. Instead, this benchmark allows quantification of the impact of technological change on the overall costs and mix of options involved in the least-cost pathway to electricity CO_2 emission footprint reduction.

The second E-PATH solution employs the potential advanced technology cost and performance characteristics to show the sensitivity of the least-cost pathway to the state of technology and provide an estimate of a more likely case. The potential advanced technology case reflects improved cost and performance characteristics for combustion turbines and combined cycle technologies based on the US EIA technology assessment.[79] In addition, the potential advanced technology case incorporates 20% lower total overnight costs for wind and solar technology versus the current best available technology profile, as shown in Table 6.

TABLE 6

Potential advanced technology cost and performance profiles

		Combustion Turbine	Combined Cycle	Wind	Solar PV
Capital costs	$/Kw	672	1094	1346	1822
Life	years	25	25	20	20
Fixed O&M	$/Kw-year	6.76	9.94	46.71	21.66
Variable O&M	$/MWh	10.63	1.99	0	0
Fuel Cost	$/mmBtu	3.5	3.5	0	0
Heat Rate	Btu/KWh	9800	6300		
Firm Capacity	Nameplate %	93	90	10	45
Property tax and Insurance	Net plant %	1.25	1.25	0.7	1.5

The simultaneous improvement of natural gas-fired and renewable technologies in the potential advanced technology case mirrors past trends. In the past decade, innovation trends in natural gas supply, especially the shale gas revolution, along with the trend

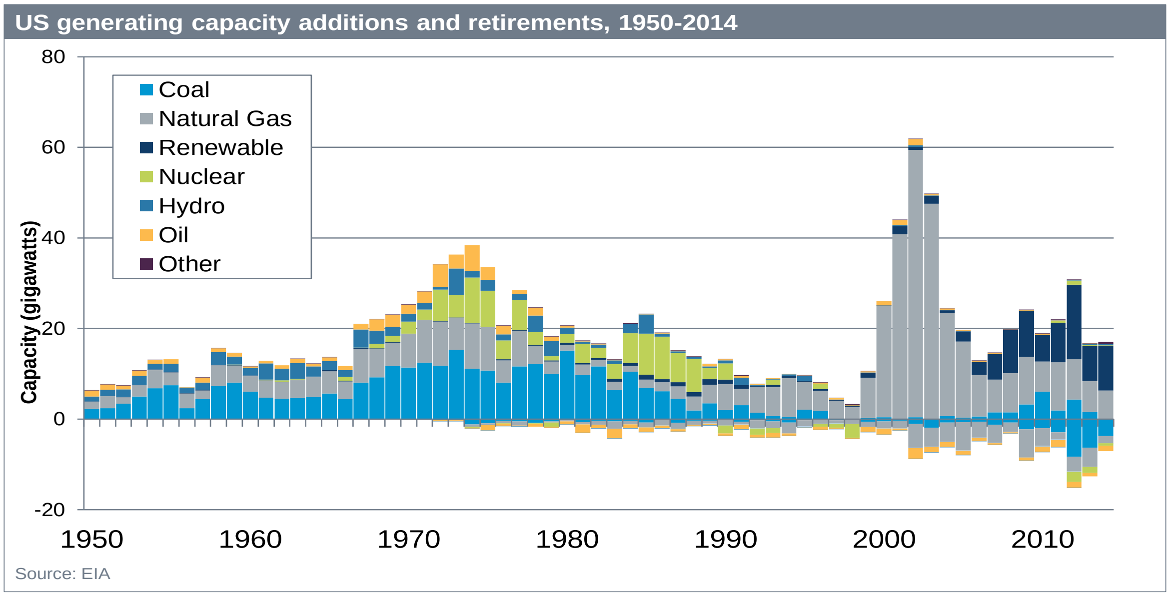
[79] Ibid

toward greater production efficiency in natural gas-fired technologies prevented declines in renewable power technologies costs from significantly altering the relative cost of renewable versus conventional generation in an electric supply portfolio.

Lead time impacts climate policy implementation costs

The costs to achieve any degree of electricity CO_2 emission footprint reduction increases as the available lead time diminishes in the absence of game changing technological advances. For example, a significant reduction in the US electricity CO_2 emission footprint in just a few years by employing current best available technology would likely be prohibitively expensive, whereas achieving the same reduction over twenty-five years would likely be far more politically feasible, all else equal. However, twenty-five years is still less than one full investment cycle in the electricity sector. Apart from hydroelectric generating resources that have expected operating lives of over one century, most electric infrastructure will begin operation, retire and be replaced within fifty to sixty years. As Figure 43 shows, the current pace of US electric generating capacity additions and retirements sum to around 20 GW per year, and since current US installed generating capacity is just over 1,000 GW, the opportunity exists to shape fuel and technology choices for roughly 2% of the US electric generating portfolio each year. The window of opportunity to address the electricity sector climate policy challenge by 2040 is roughly half the length of the infrastructure turnover interval or similarly, half of the electricity sector investment cycle. Thus, by the year 2040, investment decisions affecting roughly 50 percent of the demand and supply side alternatives still need to be made in the electricity sector. However, altering these pending decisions may not be sufficient to achieve a US electricity climate policy target of an annual 2,400 lbs. CO_2 emissions per capita over a quarter century long lead time. As a result, an effective and efficient solution may require accelerating the baseline electric technology turnover rate. Nevertheless, moving forward with a twenty-five-year long lead time involves stranding far less existing resource sunk costs compared to the alternative of achieving the same degree of CO_2 emission footprint reductions within a much shorter timeframe.

FIGURE 43



Since the state of technology can improve over time, the possibility exists that technological innovation will make meeting the climate policy challenge less costly in the years ahead. Therefore, delaying climate policy initiatives and reducing the lead time to alter demand and supply side factors in the US electricity sector could result in a lower cost pathway due to the impact of game changing technological innovations. However, delaying climate policy implementation in anticipation of game changing technological innovations appears to be a risky proposition. Delaying alterations to demand and supply-side factors locks in the status quo and increases the demands on the eventual changes from game-changing technological improvements. Similarly, shifting the emphasis of climate policy initiatives toward research and development activities and away from efforts to implement current best available technology options also involves making a bet that delaying alterations to the demand and supply-sides of the electricity sector will lower the costs of achieving climate policy targets within the available window of opportunity. Again, betting that R&D can payoff in the available widow of opportunity to address climate change is a risky proposition.

The future state of technology is difficult to predict. This uncertainty translates into uncertainty regarding the optimal climate policy lead time and makes choosing a lead time a largely qualitative rather than quantitative decision. This US least-cost pathway assessment reflects a qualitative decision to maximize the lead time. The reasoning follows from three observations:

- **Change takes time**--experience shows that the typical progression from technological innovation to wide scale commercial deployment typically takes decades. Therefore, the odds are that technological innovation will not improve fast enough to offset the higher cost associated to shorter lead time climate policy implementation.

- **Technological optimism is appealing but unrealistic**--behavioral economists warn that human beings suffer from a bias to overestimate of our ability to shape the future.[80] As a result, acting sooner rather than later counters the tendency to bet on the appealing, but low probability outcome that we can simply invent the future that we want within the next several decades.
- **It is better to be safe rather than be sorry**--maximizing the expected net benefits from climate policy initiatives require more conservative bets regarding improvements in the available state of technology. Uncertainty regarding climate sensitivity to atmospheric concentrations of CO_2 produce asymmetric risks. The IPCC Fourth assessment report indicates that, "Anthropogenic warming could lead to some effects that are abrupt…if large-scale abrupt climate change were to occur, its impact would be quite high."[81] The costs of doing too much to address climate change are more certain than the costs of doing too little. In particular, uncertainty regarding climate sensitivity to atmospheric concentrations of CO_2 produce scenarios where doing too little pushes average global temperatures past critical thresholds that accelerate a feedback loop and cause catastrophic environmental impacts. This risk asymmetry leads to expectation that the costs of doing too little to address climate likely exceed the cost of doing too much. Therefore, the expected costs from delay and potentially overestimating technological innovation exceed the expected costs of going forward and potentially underestimating changes in the state of technology.

Following a least-cost pathway requires shifting away from business-as-usual

The California track record shows that the current leading-edge of US climate policy is not on the least-cost pathway to reducing future electricity sector CO_2 emission footprints. More broadly, shifting away as soon as possible from the current mix of uncoordinated Federal and state climate policies will minimize the cost of reducing the US electricity CO_2 emission footprint by avoiding the ongoing deployment of scarce resources to inefficient initiatives.

Baseline 2040 US electricity CO_2 emission footprints

The US 2040 electricity CO_2 least cost pathway analyses aggregate the least-cost pathway assessments of the three US electrical interconnections—Eastern, ERCOT and Western. The interconnections remain independent and ongoing trend transmission investments are assumed adequate to accommodate the changes to the demand and supply-sides of the electric systems over the lead-time interval.

Shifting away from business-as-usual produces a future year CO_2 emission footprint starting point for the least-cost pathway assessment that reflects no additional scarce resources being deployed in climate policy initiatives. The baseline reflects the least-cost combination of demand and supply options available to provide future demands for electric services with a zero charge on CO_2 emissions. As a result, initial conditions in the future year baseline will differ from current conditions because non-policy driven trends exist that shift demand and supply-side CO_2 emission footprint factors through time.

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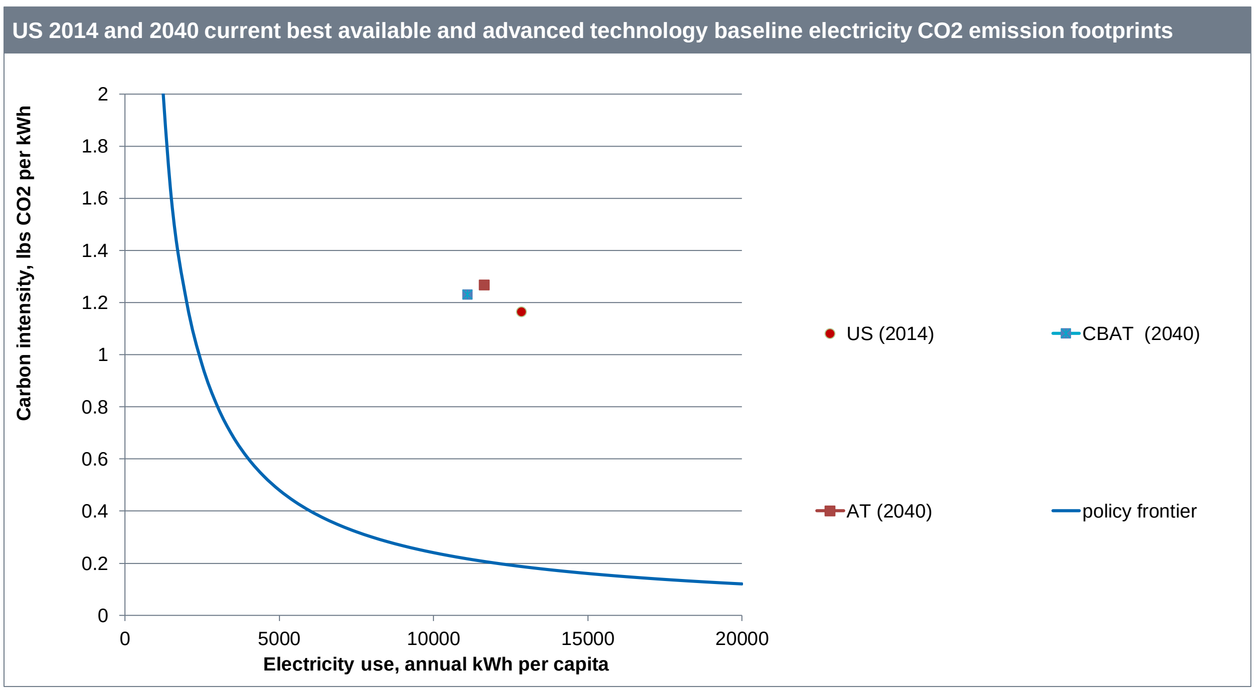
[80] Bazerman and Watkins, Predictable Surprises, Harvard Business School Press, 2004

[81] IPCC, Climate Change 2007: Synthesis Report, Contribution of working Groups I, II and III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, pg. 53.

As Figure 44 shows, the baseline 2040 baseline US electricity CO_2 emission footprint in the current best available (CBAT) and potential advanced technology (AT) cases involves a slight change from the current level. In both cases, the baseline demand-side (x-axis), shows the downward influence of electricity consumption efficiency trends exceed the upward influence of electrification trends and the net effect causes future electricity consumption per capita to decrease from current levels. The decline in electricity consumption per capita is less in the potential advanced technology case due to more efficient production technologies generating lower retail electricity prices and thus higher consumption. On the supply-side (y-axis), the expected economic turnover of electric production technologies with no charge on CO_2 emissions leads to an increase in electricity generation CO_2 emission intensity. The increase reflects a continued expansion of the natural gas-fired technology generation share in the supply mix and a generation share decline, albeit lower than the current level, for coal-fired technologies. Reinforcing this rate of increase in CO_2 emission intensity is the reduction in the wind and solar generation shares due to the elimination of renewable mandates and subsidies, along with the trend toward lower hydroelectric and nuclear generation shares due to retirements.

FIGURE 44



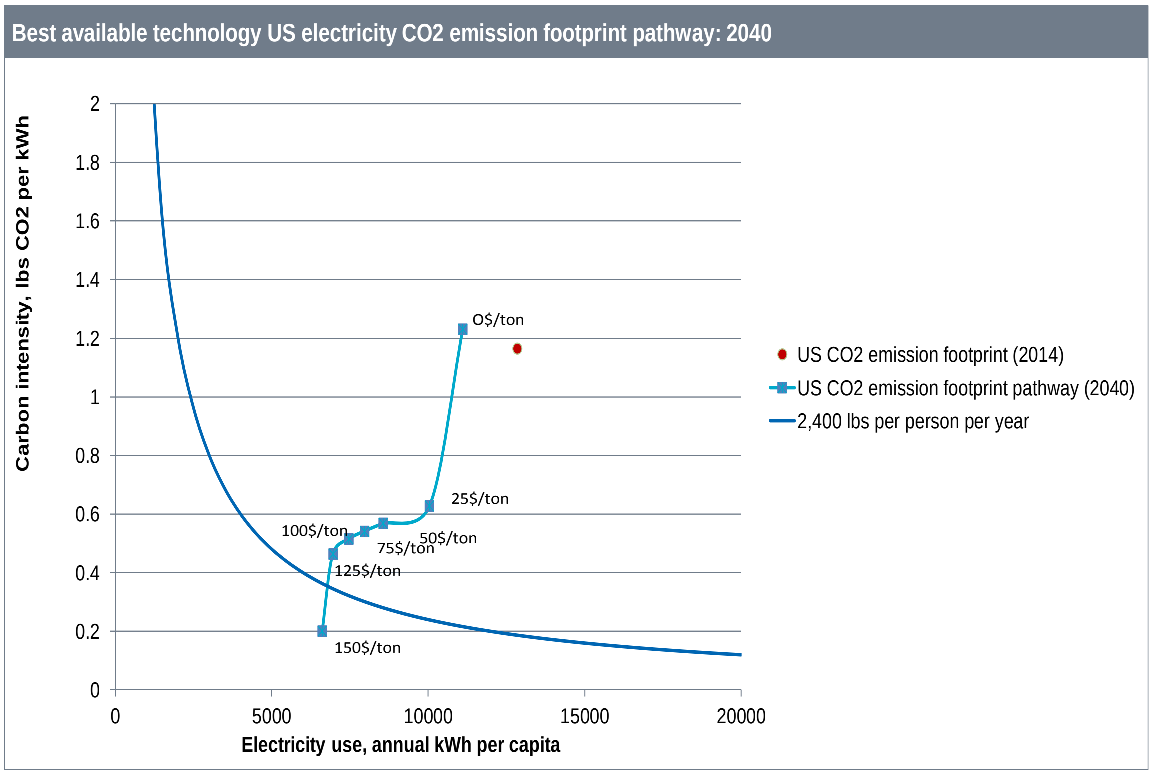
The net effect of expected changes in demand and supply-side factors create an electricity climate policy challenge to reduce the 2040 baseline CO_2 emission footprints by about 80 percent to close the gap to the annual 2,400 lbs. CO_2 emissions policy goal by 2040.

The baseline 2040 US electricity carbon footprints involve an absolute annual electric sector CO_2 emission level of around 2.6 Gt. This baseline emission level is over one-third higher than the 2014 level. Therefore, meeting the electricity CO_2 emission policy challenge involves reducing the absolute level of electricity sector CO_2 emissions by roughly 85 percent.

The current best available technology least-cost pathway to reducing the US baseline 2040 electricity CO_2 emission footprint

The least-cost pathway to reducing the 2040 baseline US electricity CO_2 emission footprint with current best available technology is shown in Figure 45. Each block along the least-cost pathway reflects the constrained cost minimization outcome achieved by incorporating an accumulating, incremental $25 per ton CO_2 emission charge from the baseline starting value of zero.

FIGURE 45

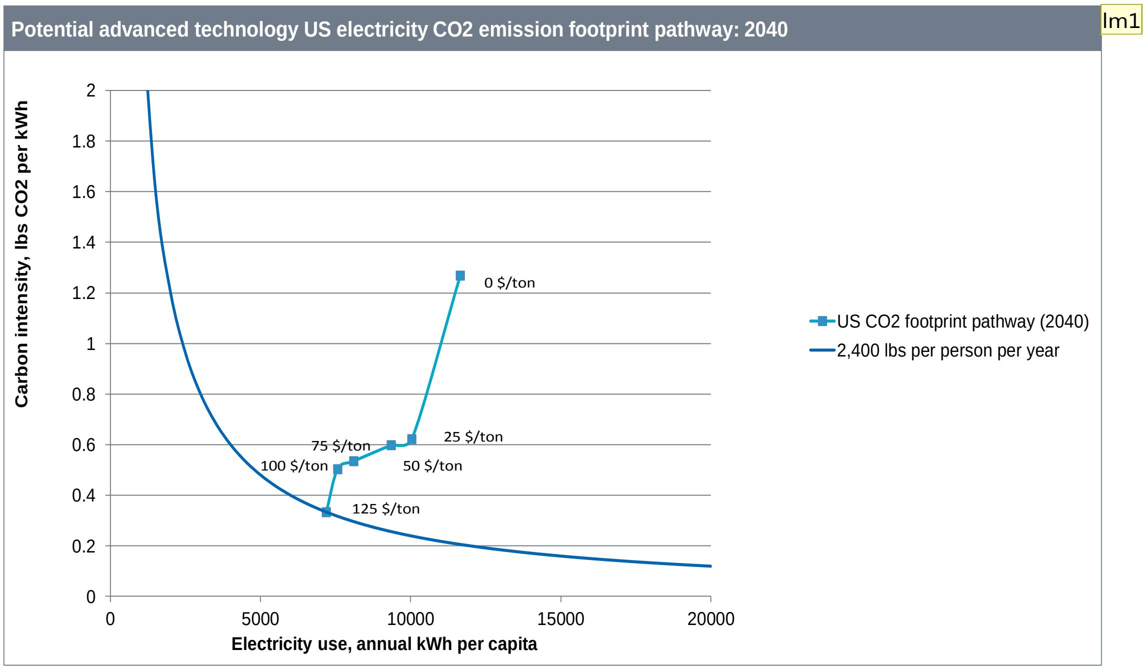


Reaching the 2040 CO_2 emission footprint of 2,400 lbs. annual CO_2 emissions per capita requires a CO_2 emission charge between $125 and $150 per tonne.

The potential advanced technology least-cost pathway to reducing the US baseline 2040 electricity CO_2 emission footprint

The least-cost pathway to reducing the 2040 baseline US electricity CO_2 emission footprint with potential advanced technology is shown in Figure 46.

FIGURE 46

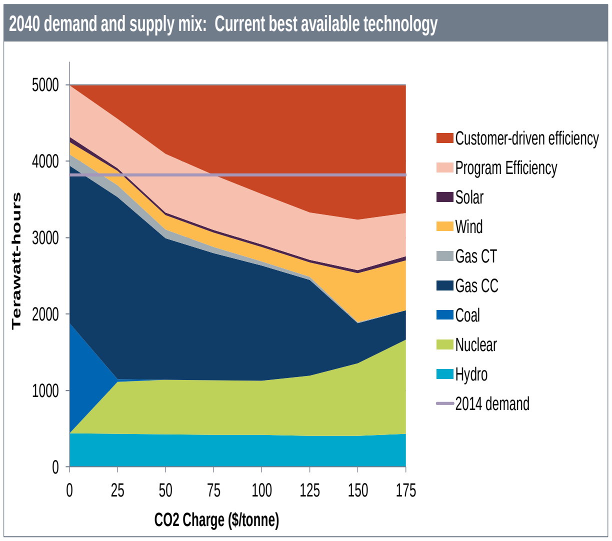


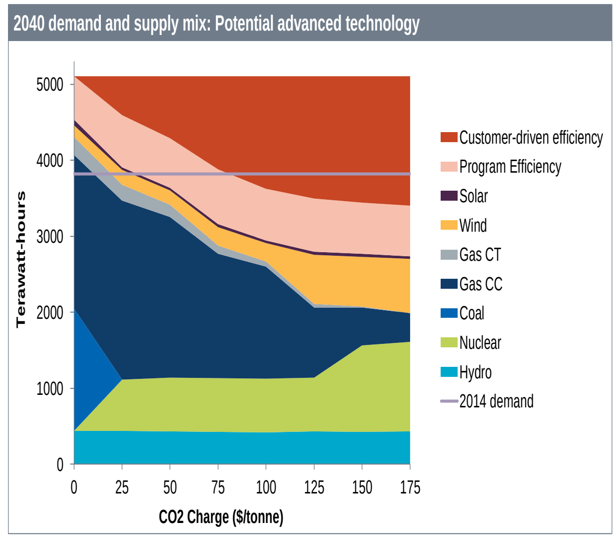
Reaching the 2040 CO_2 emission footprint of 2,400 lbs. annual CO_2 emissions per capita requires a CO_2 emission charge of around $125 per tonne in the potential advanced technology case.

US electricity CO_2 emission footprint least-cost reduction pathway demand and supply-side factor changes

The US electricity sector climate policy least-cost pathway is a complex mix of alterations to demand and supply-side factors. Figure 47 shows the alterations in the least-cost mix of demand and supply-side options associated with reductions in the 2040 electricity CO_2 emission footprint due to incrementally higher CO_2 emission charges.

FIGURE 47





Increasing electric consumption efficiency is part of the least-cost pathway all along the way as incremental CO_2 emission charges increase, but consumption efficiency gains arise primarily though internalizing a CO_2 charge into retail electricity prices, rather than by expanding rate payer-funded efficiency programs. The result reflects the CO_2 emission charge contributing to a price signal that drives the demand-side relationships reflecting reasonably well-informed consumers making rational decisions when evaluating the cost/benefit tradeoffs of efficiency investments.

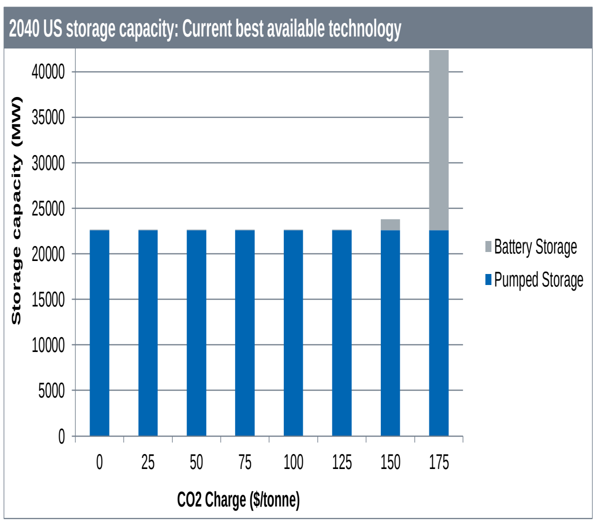
Increasing electricity consumption efficiency through consumer responses to prices and through rate payer-funded programs both involve positive and increasing costs. Therefore, as the CO_2 emission charge increases, more electric consumption efficiency investments become economic and when the CO_2 emission changes reaches between 25 and 50 dollars per tonne, the least-cost pathway incorporates enough demand side alterations to completely offset the factors driving baseline electric energy growth from 2015 to 2040. Further, reaching the 2,400 annual lbs. CO_2 emission target with a $175 per tonne charge involves 2040 electric energy demand falling by around one-third from the 2015 base year levels.

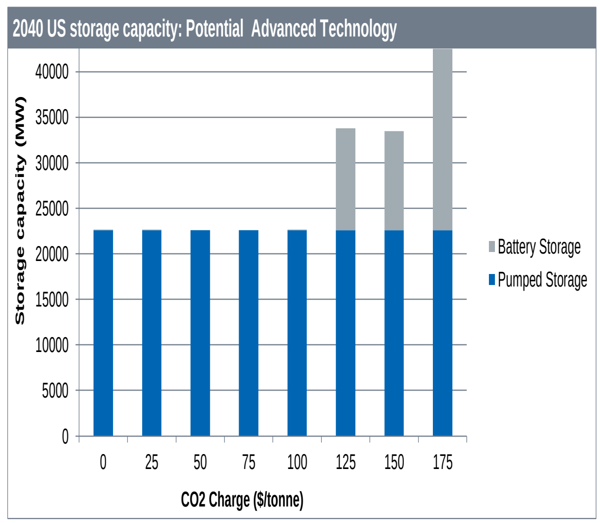
Wind and solar resources are part of the least-cost pathway, but not as the primary source of generation even in the deep CO_2 emission reduction cases. The least-cost pathway methodology incorporates economic dispatch of power supply in real time to meet net load and as the CO_2 emission charge increases, the limiting factor to higher wind and solar shares is the cost to integrate larger shares of intermittent renewable generation.

Within the intermittent renewable least-cost generation share, the relative cost and performance of wind technologies versus solar technologies favor wind technologies. Within the smaller solar generation share, the relative cost and performance of utility scale solar versus distributed solar favors utility scale solar technologies with the capability to track the changing position of the sun.

As Figure 48 shows, electric storage technologies make up a small part of the least-cost pathway. The going forward costs of legacy storage cause little economic retirement of pumped storage resources but a lack of feasible additional development sites limits future expansion. Battery storage technology performance in both cases involves a daily charging and discharging cycle to optimize the role of storage within the entire portfolio rather than an optimization of an exclusive application to intermittent renewables. The primary limit on battery storage technology expansion is that load following generation technologies remain the most cost effective option to meet most of the variation in net load throughout the year.

FIGURE 48





The natural gas generation share remains steady as the legacy coal generation share declines due to additional substitution of natural gas for coal-fired generation. Natural gas-fired generation technologies remain a significant part of the supply portfolio even when CO_2 emission charges reach the $175 per ton level in the current best available technology case. However, higher CO_2 emission charges drive to more efficient natural gas-fired generation by shifting the technology mix away from simple cycle and toward combined cycle generation technologies.

The least-cost pathway does not involve the elimination of fossil-fueled generation because natural gas is more than a “bridge fuel” to a lower carbon future. Natural gas-fired resources remain a significant part of the least-cost supply portfolio when the US electricity sector moves along the least-cost pathway to the 2,400 annual lbs. CO_2 emissions per capita goal.

Continued operation of high utilization conventional coal-fired generation technologies remains cost effective in the 2040 baseline with a zero CO_2 emission charge. However, coal-fired generation shares decline rapidly with the introduction of a positive CO_2 emission charge. Most coal-fired generation is displaced as the CO_2 emission charge moves up to and past the $50 per ton level. However, coal-fired capacity remains operable even as CO_2 emission charges reach $100 per ton because the low going forward costs of legacy coal capacity keeps coal resources in the supply portfolio as a seasonal source of capacity with associated seasonal dispatch patterns and low annual plant factors. Since fossil-fueled generation remains in the least cost outcome, coal generation could remain in the least cost generation mix with an advance in CO_2 emission capture and sequestration technology if the cost, performance and emission profile for the partial coal-fired CC&S option were competitive with the natural gas-fired combined-cycle technology.

Nuclear generation share declines in the baseline when CO_2 emission charges are zero. However, moving from zero to a $25 per ton charge reverses the prospects for continued nuclear resource operation and life extension. New nuclear power plants become cost effective in the least-cost pathway as the CO_2 emission charge reaches 100 to 125 dollars per tonne respectively, in the current best available technology and in the potential advanced technology cases.

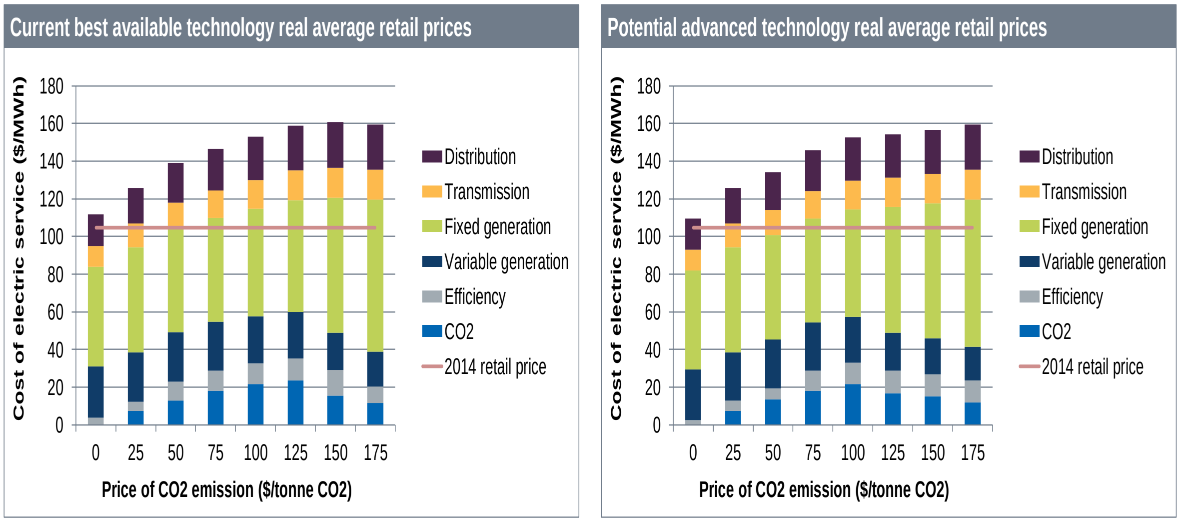
The hydroelectric generation share remains relatively steady because the continued operation and refurbishment of hydro resources are cost effective along the whole range of CO_2 emission charges. However, natural endowments of feasible hydroelectric sites limit hydroelectric resources expansion in the decades to come.

Cost and retail price impacts

Figure 49 shows that if nothing is done to address climate change, the expected real price of electricity increases from 2 to 5 percent by 2040 depending on the available state of technology. The costs associated with following the least-cost pathways to achieving the 2,400 annual lbs. CO_2 emission per capita by 2040 translate into real retail electricity price increases of around 42 to 45 percent from the baseline levels depending on the state of technology case. Retail price levels in the potential advanced technology case are only a few percentage lower than the current best available technology case because the retail prices include significant common cost components that are independent of the technology differences, including the legacy generation costs, the transmission and distribution charges.

Retail prices increase proportionally more than electric consumption declines and thus, following the least-cost pathway to reducing the electricity CO_2 emission footprint would not involve a decline in the average monthly electricity bill.

FIGURE 49


Current best available technology real average retail prices
Cost of electric service ($/MWh)
180
160
140
120
100
80
60
40
20
0
0
25
50
75
100
125
150
175
Price of CO2 emission ($/tonne CO2)
Distribution
Transmission
Fixed generation
Variable generation
Efficiency
CO2
2014 retail price
Potential advanced technology real average retail prices
Cost of electric service ($/MWh)
Price of CO2 emission ($/tonne CO2)
Distribution
Transmission
Fixed generation
Variable generation
Efficiency
CO2
2014 retail price

Chapter 6: Climate policy implications

The potential for climate policy failure

The scale and scope of the global warming problem impose both the size and pace of the CO_2 emission reductions required for an effective solution. The current assessment of the problem requires most developed world electricity systems to make significant and sustained reductions in their electricity CO_2 emissions footprints within the next several decades.

No country can solve the global warming problem on its own. Consequently, an effective solution requires multilateral national climate policy initiatives across key GHG emitting sectors, including the electricity sector. Therefore, the overall success of electricity sector climate policy initiatives requires two conditions. First, a developed economy electricity sector needs to effectively address the electricity climate policy challenge. Second, other power systems around the world also need to follow suit within the following couple of decades. The implication is clear, inefficient unilateral CO_2 emission reduction policies will contribute to an overall failure to solve the global warming problem because these efforts are lost opportunities to set an attractive example for power systems around the world to follow.

Global climate policy is not moving toward the adoption of a uniform anthropogenic CO_2 emission charge based on estimates of the social cost of carbon. As a result, the electricity sector is not on track to pursue CO_2 emission reductions up to the point where marginal CO_2 abatement costs across all demand and supply-side options equal the social cost of carbon. The global electricity sector is also not on track to do its part to limit the impact of global warming to a two-degree increase from the average pre-industrial temperature level. Current economic and technology trends, along with business-as-usual climate policy approaches, create a high probability of climate policy failure in reaching the goals associated with the 22 Gt by 2040 two-degree scenario even though these goals set a lower bar for policy success versus the more aggressive IPCC 2.6 Representative Concentration Pathway scenario goal of achieving net zero anthropogenic GHG emissions by around 2065.[82]

The window of opportunity to meet the electricity climate policy challenge spans only half of the electricity sector infrastructure turnover and investment cycle. As this window of opportunity closes, the increasing potential for climate policy failure creates a sense of urgency to shift away from business-as-usual climate policy initiatives and move toward climate policy initiatives designed to follow least-cost pathways to CO_2 emission footprint reductions. Reinforcing this sense of urgency is the diminishing likelihood that technological innovation can ride to the rescue as the required lead time for research, development and widespread deployment of game-changing technology advances becomes increasingly beyond the remaining window of opportunity to implement necessary changes at the required scale.

The US is withdrawing from the Paris Climate Agreement. However, the political pressure to do something about climate change is not going away. As a result, current US climate initiatives are an uncoordinated mix of Federal and state climate policies with a bias

[82] IPCC, 2014: Summary for Policymakers, In: Climate Change 2014, Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Edenhofer, O., R. Pichs-Madruga, Y. Sokona, E. Farahani, S. Kadner, K. Seyboth, A. Adler, I. Baum, S. Brunner, P. Eickemeier, B. Kriemann, J. Savolainen, S. Schlömer, C. von Stechow, T. Zwickel and J.C. Minx (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

toward appealing but unrealistic optimistic policy formulations that underestimate costs and produce a low probability of achieving effective outcomes.

Business-as-usual US climate policy initiatives continue because a consensus does not exist regarding the best mix of demand and supply-side changes to pursue to achieve climate policy objectives. The range of opinion regarding what to do is quite extreme and often quite different from the least-cost pathway demand and supply-side changes. For example, several states are debating ratcheting up renewable power supply portfolio requirements well beyond the cost-effective generation share. Already, some states have reset goals to 50 percent renewable shares by 2030 and one state (Hawaii) reset its mandate to 100 percent renewable energy by 2045.

Current US electricity climate policy initiatives are not demonstrating an attractive example for other power systems to follow. Simply putting a charge on CO_2 emissions (while eliminating the distortions of efficiency program and renewable generation mandates and subsidies) would circumvent the debate about what options to pursue and thus avoid having to build a consensus regarding what to do because the price signal would coordinate and shape an efficient mix of initiatives. An alternative approach involves incorporating a CO_2 emission charge into an integrated resource planning process that aligns with the dollar per tonne charge necessary to move along the least-cost pathway to the desired CO_2 emission footprint. However, the integrated resource planning approach is difficult to implement without using retail price signals as the primary policy implementation mechanism, especially on the demand-side with numerous and heterogeneous options.

The bottom line is that the US could shift climate policy to rely primarily on a CO_2 emission charge to achieve GHG emission goals and increase the probability of demonstrating an attractive example for other power systems worldwide to follow.

Confronting costs

Confronting a realistic assessment of the cost to meet the electricity climate policy challenge is difficult. The E-PATH analyses indicates that it is going to be expensive for the US electricity sector to do its part to limit the impact of global warming to a two-degree increase from the average pre-industrial temperature level. Although the E-PATH analyses indicate that climate policy cost depends on the expected state of technology, and that innovation and technological advance could lower the overall cost to achieve any level of CO_2 emission footprint reduction, nevertheless, the E-PATH analyses shows that, without a game-changing technology improvement, achieving electric climate policy targets is going to expensive even with potential advanced technologies, and these costs will challenge the political tolerance to implement the policies.

The E-PATH analyses differs from some influential studies that suggest addressing the climate policy challenge does not require confronting the political tolerance for incurring costs. For example, Figure 50 is a summary of the White House press release of the proposed Clean Power Plan reflecting an EPA assessment of cost to lower US electric sector CO_2 emissions by around twenty percent from 2012 levels. The policy assessment suggests that such significant reductions in electric sector CO_2 emissions are possible though a policy approach that generates savings rather than costs.

FIGURE 50

President Obama White House August 3, 2015 Clean Power Plan press release

The Clean Power Plan will:

Boost our economy by

- Leading to 30% more renewable energy generation in 2030
- Creating tens of thousands of jobs
- Continuing to lower the costs of renewable energy

Save the average American family

- Nearly $85 a year on their energy bills in 2030
- Save consumers $155 billion from 2020–30

The EPA cost assessment of the Clean Power Plan was not the first influential study to postulate that solving the global warming problem does not require confronting politically challenging costs. The IEA World Energy Outlook Special Report, *Energy and Climate Change* developed a "Bridge Scenario" that halts GHG emission growth by 2020 and subsequently delivers the IPCC recommended substantial and sustained reductions in global anthropogenic GHG emissions by 2030 while not affecting global or regional prospects for economic growth. The IEA concluded that the level of ambition to reduce energy-related greenhouse gas emissions can be raised appreciably at no cost to global economic activity.[83] McKinsey and Company produced a similar study focused on the US that showed a CO_2 emission cost abatement curve with accumulating negative costs from efficiency gains available from employing currently available technologies at a scale sufficient to offset the accumulated positive costs of other CO_2 emission abatement actions and allow the US economy to double in size by 2030 while reducing GHG emissions below 2006 levels at a total cost of zero.[84]

In 2015, Mark Jacobson et al. produced a study finding that the US electricity sector could feasibly transition to low cost solutions to grid reliability problems with 100 percent of electric supply coming from intermittent wind, solar and hydroelectric resources by 2050.[85]

The idea of dramatically reducing GHG emissions at little or no cost naturally raises red flags because the obvious question is why such an attractive path to the future is not already being pursued. The Economist Magazine answered this question in an article illustrating the McKinsey CO_2 emission abatement cost curve and concluded that "The result is a testament to economic

[83] International Energy Outlook, *World Energy Outlook Energy and Climate Change Special Report*, 2015, pgs. 68, 99, 100, 106
[84] McKinsey and Company, *Reducing U.S. Greenhouse Gas Emissions: How Much at What Cost?* U.S. Greenhouse Gas Abatement Mapping Initiative Executive Report, December 2007.
[85] Mark Jacobson et al., *Low-Cost Solutions to the Grid Reliability Problem with 100% Penetration of Intermittent Wind, Water and Solar for All Purposes,* Proceedings of the National Academy of Sciences USA, 112:15060-15065.

irrationality." [86] A group of 21 prominent energy and climate scientists reviewed the Jacobson study and found significant analytical shortcomings and concluded that, "Policy makers should treat with caution any visions of a rapid, reliable and low-cost transition to entire energy systems that relies almost exclusively on wind, solar and hydroelectric power."[87]

The EPA projected US electric sector CO_2 emission reduction associated with the Clean Power Plan underpinned the Obama administration Paris Climate Accord NDC. The political shift from the Obama administration to the Trump administration indicates a shift away from the no cost assessment to reduce US electricity sector CO_2 emissions and toward a confrontation with the implications of significant costs, as shown in Figure 51.

FIGURE 51

President Trump White House June 1, 2017 Paris Climate Accord press release

The United State withdrawal from the Paris Climate Accord will:

Boost our economy by
- Saving 2.7 million jobs by 2025

Save the average American family
- $7,000 in disposable income by 2040

The divergence of opinion regarding climate policy cost impacts explains some of the current conflict in climate policy formulation. From the low-cost perspective, there is no cost constraint to moving climate policy forward, and no concern that doing so could create a competitive disadvantage if other nations do not follow suit. Conversely, recognition of significant costs creates a political challenge to move forward and exposes a significant risk that unilateral actions can generate a competitive disadvantage versus other countries that do not follow suit and incur their own CO_2 emission reduction costs. The implication is that costly unilateral actions could produce a policy failure if the impact of unilateral action is offset by failures to act elsewhere.

The E-PATH analysis cost estimates appear to differ from the low, zero or negative cost studies for three reasons. First, the cost to increase electric consumption efficiency is positive and increasing because the E-PATH demand analysis forces the rejection of the hypothesis that a massive pool of negative cost efficiency options exists due to consumers being ill-informed and irrational and chronically underinvesting in opportunities to increase consumption efficiency. Second, the E-PATH analysis incorporates the critical

[86] The Economist, June 2nd-8th, 2007, Special Report, *How business is tackling climate change*.
[87] Christopher Clack, et al., *Evaluation of a Proposal for Reliable Low-cost Grid Power with 100% Wind, Water, and Solar*, Proceedings of the National Academy of Sciences, 2017. www.pnas.org/cgi/doi/10.1073/pnas.1610381114.

time dimension of balancing electric demand and supply in the power system cost analyses and does not incorporate time ignorant LCOE cost assessments of electric supply options that overestimate the grid parity of intermittent electric supply resources. Third, the E-PATH holds the bias to technological optimism in check and does not assume game-changing technological innovations will experience widespread deployment within an interval less than or equal to half of the electricity infrastructure turnover and investment cycle.

Confronting realistic CO_2 emission reduction costs does not constitute an argument for inaction regarding climate policy. Instead, the climate policy implication of confronting realistic cost estimates is that successful policy formulation and implementation depends on achieving policy goals at a politically acceptable cost. This makes policy formulation to pursue the least-cost pathway critical to a successful outcome.

Social Cost of Carbon

Setting a climate policy goal to equate the marginal costs and benefits based on the mid-range SCC estimate results in a CO_2 emission charge that is less than half of the CO_2 emission charge that closes the gap to the 2,400 annual lbs. CO_2 emissions per capita. However, since CO_2 emission abatement involves diminishing marginal returns, the SCC mid-point based charge produces more than half of the CO_2 emission abatement required to close the gap to the 2,400 annual lbs. CO_2 emissions per capita frontier. Although the climate policy goals associated with the SCC solution framework differ from the goals associated with the CO_2 emission sources and sink equilibration framework, employing a charge on anthropogenic CO_2 emissions maps the efficient implementation pathway in both cases.

Political will to pursue the least-cost pathway to electricity CO_2 emission footprint reductions

The pathway ahead for US electric sector climate policy is a political decision that hinges on the political tolerance for incurring the costs associated with addressing the climate policy challenge. Yet, even if the US electricity sector incurred the costs to meet its climate policy challenge, failure is still an option if other power systems worldwide fail to follow suit. Thus, part of the political will to address the climate policy challenge depends on embracing the opportunity and risk of leading, rather than following.

An inverse relationship likely exists between the costs and risks to achieve climate policy goals and the political will to move forward. The implication is that the political will to meet increasingly ambitious climate policy targets will likely diminish at an increasing rate. The variance in political will across states generates the current patchwork of uncoordinated state and Federal climate policies. Reframing US climate policy could reduce the inefficiencies of the status-quo. A politically feasible way forward probably requires a combination of phasing-in an effective climate policy approach in conjunction with recirculating the CO_2 emission charge revenue. For example, CO_2 emission charges of 75 to 125 \$(2014) per tonne in the potential advanced technology case involves recycling 58 to 67 billion dollars per year back to consumers to support purchasing power, to counter regressive cost burden distributions and to mitigate cross-border trade distortions.

The window of opportunity is closing for the US to address the electricity climate policy challenge by following a least-cost pathway to achieving lower future electricity sector CO_2 emission footprints. Delaying the shift away from current policy approaches to a CO_2 charge driven policy approach designed to pursue the least-cost pathway causes the available lead time to decrease and thus, likely increases the cost to achieve any level of future CO_2 emission reduction. As a result, delay reduces the likelihood of generating the political will to incur the cost of meeting the climate policy challenge.

Even a phased approach looks difficult to implement. Implementing a CO_2 emission charge of around 40 $(2014) per tonne would produce an expected real retail price increase of around 25 percent. This approach would be relatively more politically tolerable than implementing the 125 $(2014) per metric ton CO_2 emission charge that translates into an expected greater than 40 percent real retail price increase to pay for closing the gap to the 2,400 annual lbs. CO_2 emission per capita by 2040. However, to put this into perspective, note that the least politically feasible approach appears to be trying to achieve the "last mile" of CO_2 emission reductions associated with reaching a net-zero CO_2 emission footprint goal around the year 2065.

The US electricity sector CO_2 emission reduction least cost pathway indicates that annual revenues from a CO_2 emission charge peak around 67 $(2014) billion with a CO_2 emission charge of 100 $(2014) per metric ton. A political window of opportunity may open in the future if shifting US climate policy toward a CO_2 emission charge is also considered a feasible way to address Federal fiscal deficits and a growing national debt in lieu of increasing individual and corporate income tax rates.

Reframing US electric sector climate policy

Shifting to efficient and effective policy approaches presents a political challenge because making such a change requires recognition of unappealing realistic cost assessments. Seizing the opportunity to lead the global electricity sector by example requires the US electricity sector to demonstrate how to follow the least cost pathway to achieving electricity CO_2 emission footprint policy goals at a politically tolerable cost by around 2040. If other power systems followed suit within the subsequent couple of decades, then the global electricity sector could do its part to solve the global warming problem.

Reshaping US electricity sector climate policy to pursue an efficient and effective outcome involves six policy recommendations:

1. **Reframe the policy debate**—the inefficiencies and ineffectiveness of current popular policy approaches need to be exposed to move a political consensus toward taking an alternative pathway.
2. **Develop a political strategy**—organize supporting interests and take advantage of the need for additional Federal revenue sources to set the timing and magnitude for a shift award from the status-quo and toward a CO_2 emission charge based climate policy initiative.
3. **Replace business-as-usual climate policy approaches with an appropriate CO_2 emission charge**--phase out command and control environmental policies such as mandates and subsidies, and phase in a CO_2 emission charge starting at a 40 ($2014) per metric ton with an initial escalation rate designed to move toward the E-PATH potential advanced technology case-based target of 125 $(2014) per metric ton. The phase-in should involve a predictable schedule of periodic reviews to adjust the CO_2 emission charge based on the level and rate of change in the electricity carbon footprint as well as changes in the state of technology and the associated costs of CO_2 emission abatement.
4. **Fully reflect electricity costs in retail price signals**—to coordinate the complex and heterogeneous cost-effective efficiency investments.
5. **Recirculate some CO_2 emission charge revenues**—to mitigate regressive cost impacts and augment any necessary border tax adjustments to mitigate distortions to industrial competitiveness from trading partners whose electricity sector climate policies do not follow suit to effectively address the electricity sector climate policy challenge.

6. **Lead by example**—encourage other nations and power systems to impose equivalent CO_2 emission charges and encourage CO_2 emission allowance trading where cap-and-trade approaches are employed with reliable CO_2 emission accounting,

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