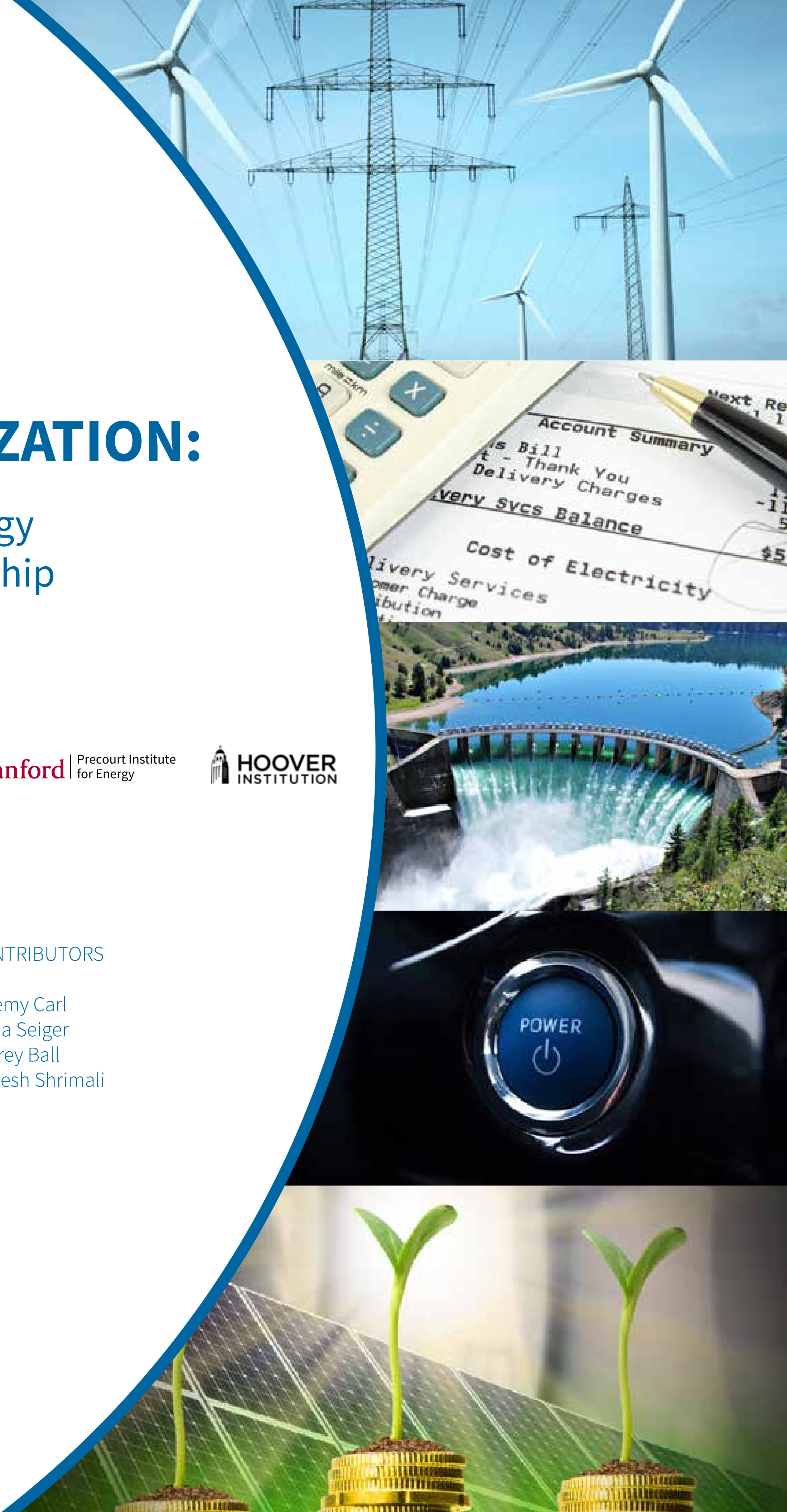
DERISKING DECARBONIZATION:

Making Green Energy Investments Blue Chip



Stanford | Steyer-Taylor Center for Energy Policy and Finance

Stanford | Precourt Institute for Energy

HOOVER INSTITUTION

PRINCIPAL AUTHORS

Dan Reicher
Jeff Brown
David Fedor

CONTRIBUTORS

Jeremy Carl
Alicia Seiger
Jeffrey Ball
Gireesh Shrimali

October 27, 2017

Table of Contents

Table of Contents, continued

Chapter 1: Introduction

This framing paper for the launch of the Stanford Clean Energy Finance Initiative considers the challenge and opportunity of dramatically scaling up global investment in clean energy deployment. Simply put, the International Energy Agency (IEA) reports that we are currently investing globally roughly one-third of the private and public funds necessary to have a shot at staying within the 2 degrees Centigrade warming threshold that could help avoid the most severe impacts of climate change. This paper takes a look through an "investor lens" at the risks that stand in the way of adding tens of trillions of dollars globally over the next 25 years to the current clean energy investment trajectory.

The paper analyzes several different types of investment risk, takes an initial cut at the solutions that might address them, and identifies future research steps.

The audience for the paper is broad given the important areas of technology, policy, and finance that undergird clean energy deployment. The finance community looms large in how we analyze investment risk and consider solutions. Policymakers are also important given the impact that policy at all levels has on investment flows and deal-making.

The framing paper focuses globally but pays particular attention to clean energy investment risks in the top three carbon-emitting nations — the U.S., China and India — with the largest focus on the U.S. It takes a broad look technologically across the entire clean energy spectrum including energy efficiency, the full range of renewables, nuclear power, carbon capture and storage (CCS), natural gas, cogeneration, as well as key enabling technologies including transmission, storage, and demand response.

The paper was written by a team assembled from two Stanford energy groups: the Steyer-Taylor Center for Energy Policy and Finance (STC) and the Hoover Institution ("Hoover"). STC is a joint center of the Stanford law and business schools that "explores and develops economically sensible policy and finance solutions that advance cleaner, more secure energy." Hoover is a "public policy think tank promoting the principles of individual, economic, and political freedom." The groups have collaborated before and given their sometimes differing substantive and political takes on energy issues we believe joint efforts yield a more pragmatic and balanced outcome. Dan Reicher (STC), Jeff Brown (STC) and David Fedor (Hoover) are the paper's principal authors, with contributions from Jeremy Carl (Hoover), Alicia Seiger (STC), Jeff Ball (STC), and Gireesh Shrimali (STC)

The framing paper complements eight "solutions papers" that address specific aspects of investment risks. Together these analyses support the November 1, 2017, Stanford Clean Energy Finance Forum. This paper was funded by a gift from Bank of America Merrill Lynch to the Stanford Precourt Institute for Energy. The gift provides Stanford with full independence to conduct the research, draw conclusions and write this report.

1.1 CHALLENGES AND OPPORTUNITIES

Climate change, resulting from a massive increase in global greenhouse emissions over many decades, poses a serious existential challenge. This paper will not analyze the science that underlies this assumption. Rather the issue we explore is how to pay for the unprecedented investment that is required to address the problem, as it relates to decarbonizing the global energy system. We look at this challenge based on recent data and analysis from the IEA that quantifies the projected investment across a range of energy technologies required to achieve the agency's "450 Scenario," an ambitious scenario that IEA believes could limit atmospheric CO_2 to 450 parts per million (ppm) and thus keep global warming below 2 degrees Centigrade.[1]

In the 450 Scenario, IEA forecasts that investment in energy efficiency, renewables, electricity networks (transmission and storage), and low-carbon generation, such as nuclear and CCS, needs to average \$2.3 trillion per year during 25 years of the 2016-2040 planning period.[2] The average annual global spending on these areas during 2010-2015 was \$0.75 trillion.[3] Thus, the IEA's \$2.3 trillion annually under the 450 Scenario amounts to a *tripling* of spending. The \$2.3 trillion figure is admittedly an estimate and many economic, political and technological factors will shape actual spending levels, but for this framing study we adopt this average spending forecast made by a well-regarded international body. Anything close to tripling spending of this magnitude is a monumental financial challenge, on par with the challenge of rebuilding the world's energy system.

Three related challenges, confront scaling up clean energy spending in line with the IEA's 450 Scenario:

- **The Quantity Problem:** The annual investments needed to keep global warming under 2 degrees C would absorb a very significant portion of the world's total annual new investible capital;
- **The Quality Problem:** There is a mismatch between the conservative risk profile of most major institutional investors, who hold the vast proportion of the planet's capital, and the currently high-risk nature of most clean energy projects;
- **The Location Problem**: We must triple global clean energy spending within an annual global pool of investible capital that is mostly held in OECD nations, while much of it will have to be spent in the non-OECD developing world to deploy clean energy, with all the attendant risk.

FIGURE: 1. IEA's Annual Spending on Clean Energy 2016-2040 by Category (\$ billions/yr)

IEA's Annual Spending on Clean Energy 2016-2040 by Category (\$ billions/yr)

Category of Spending	2010-2015 Average	"450 Scenario" 2016-2040	Multiple 450 vs. Today (x)	Dollar Change vs. Today
Renewables	\$282	\$503	1.8x	\$220
Electricity Networks	229	288	1.3x	59
Other Low CO_2 (CCS, Nuclear, Etc.)	13	114	8.8x	101
Energy Efficiency	221	1,402	6.3x	1,181
Totals:	\$746	\$2.3T	≈3x Current Spending	\$1,561

These challenges require a major reduction in investment risk, as analyzed in the nine chapters below.

1.1.1 THE QUANTITY PROBLEM — A YAWNING GAP IN FUNDING

Tripling current clean energy spending to $2.3 trillion annually represents a large fraction — perhaps 2/3rds — of the new funds that the world's institutional investors put to work each year across all sectors. We examine total investments held by the world's largest institutional investors, including pension funds, insurance companies, mutual funds, sovereign wealth funds, and billionaires.[4] As shown in Figure 2, these assets total about $100 trillion. This is a very big number, but the not the relevant one in considering tripling annual global clean energy investment. In the language of finance, $100 trillion in this respect is a "stock", not a "flow." The $100 trillion "stock" is the aggregate value of all historical "flows" of funds received by these investors, i.e. funds that have already been spent on existing assets. More relevant are the cash inflows these investors can spend on new assets. We calculate these to average $3.4 trillion annually.[5] The IEA's 450 Scenario depends on investors purchasing clean energy stocks and bonds, or directly lending to ("debt") and investing in ("equity") clean energy projects.

The $3.4 trillion annual figure would, in theory, accommodate the IEA's $2.3 trillion annual investment figure. We say in theory because there are clearly many other global investment needs, for example, traditional infrastructure, information technology, and biotech, all competing for the same pool of dollars.[6] One additional competitor today is, of course, fossil fuels. One would expect that if fossil fuel use tapers off there would be greater capital available for clean energy projects. The IEA's figures suggest that capital investment on the order of $200-$400 billion[7] per year might be redirected in the 450 Scenario. However, this is a relatively modest figure and whether it ends up in clean energy investment, as opposed to a myriad of other sectors, depends in large part on the risk levels in clean energy projects under the 450 Scenario.

FIGURE: 2. Asset Holdings and New Investible Inflows for World's Major Institutional Investors

Asset Holder	Assets $T 2015	1-yr Change* 2014-2015 $T	Annual Avg. Inflow 2010-2015	Source
Pension Funds	$25	$1.1	$1.0	OECD Contributions as % GDP
Insurance Companies	$23	($0.9)	$0.2	OECD Assets 2015 vs. 2014 & 2010
Mutual Funds	$37	$1.9	$1.3	ICI Tables 65 & 67 for Net Purchases
Sovereign Wealth Funds	$8-9	$0.2	$0.5	SWFI Assets 2015-16; Preqin 2011-16
Billionaires	$7	($0.6)	$0.4	Forbes 2015 vs. 2014 & 2010
TOTAL	$100	$1.7T/yr Δ	$3.4T/yr Δ	Versus $2.3T /yr Need

* Insurance, SWF, and billionaires net inflows not available—change in net assets used as proxy.

1.1.2 THE QUALITY PROBLEM — A BIG MISMATCH IN RISK

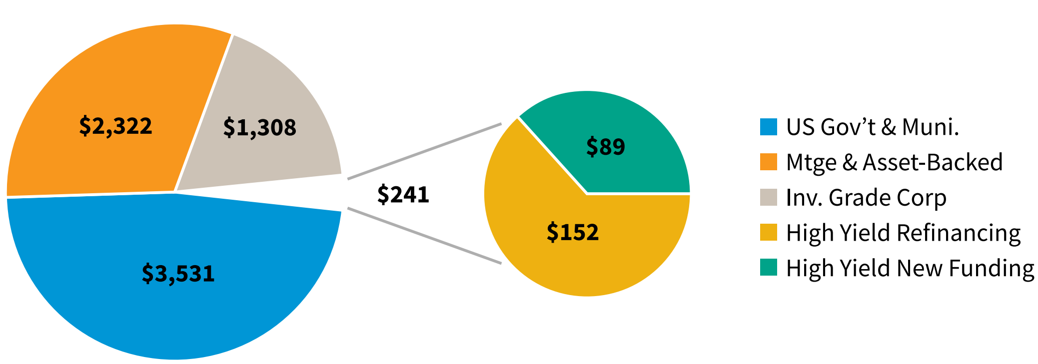
There is another challenge — the quality problem — facing the massive scale-up of clean energy investment required to address climate change. The vast proportion of institutional money is invested in conservative, low-risk asset classes, but most clean energy investments anticipated under IEA's 450 Scenario are likely to fall into the non-traditional, high-risk asset class.

Investing in clean energy projects, with one high-profile exception, tends to be a high-risk endeavor, across the technology spectrum in the IEA's 450 Scenario. From building hydropower dams, nuclear reactors and carbon capture projects to developing storage, transmission, and natural gas infrastructure to making energy efficiency upgrades to buildings there are a host of risks that can block a clean energy project. The one major exception has been utility-scale wind and solar projects that have had long-term arrangements to sell their power at relatively high fixed prices via feed-in tariffs or government-mandated power purchase agreements and enjoyed other support including tax incentives, direct cash grants, or government loans. They have typically used standard-issue wind turbines and solar panels with strong manufacturer warranties, instead of less proven technologies. Often located in OECD countries, these projects have generally avoided the rule of law, currency, and corruption issues in many developing countries. As a result, the projects could in fact access capital with investment-grade debt and eager equity investors. However, even these kinds of projects have faced challenges like permitting and grid interconnection. And increasingly they are becoming more difficult to develop as the best transmission paths are taken, "curtailment" makes project economics less attractive, and tax subsidies and feed-in tariffs phase down. Addressing these risks for even the best projects in the safest countries is important, and it is essential in developing-world projects and those using less-proven technologies.

The essence of the quality problem is that while many clean energy projects face significant risks, the vast bulk of securities successfully *sold* each year are low-risk blue chip instruments and are *held* by investors focused on low-risk blue chip categories. Two examples follow — the U.S. bond market and global pension markets — that represent a significant chunk of global assets and where reliable data is available.

U.S. Bond Market: The U.S. public bond market makes up 1/3 of world bond markets, with $7.3 trillion of annual new issue volume. As shown in Figure 3, after winnowing out U.S. government bonds, municipal bonds, mortgage securities, and high-rated corporate bonds, we are left with $241 billion (4% of the market) remaining for "high yield" bonds, i.e. bonds without investment-grade ratings that pay

FIGURE: 3. "New Money" High Yield Bonds = 1% of 2016 U.S. Bond Market (Billions)

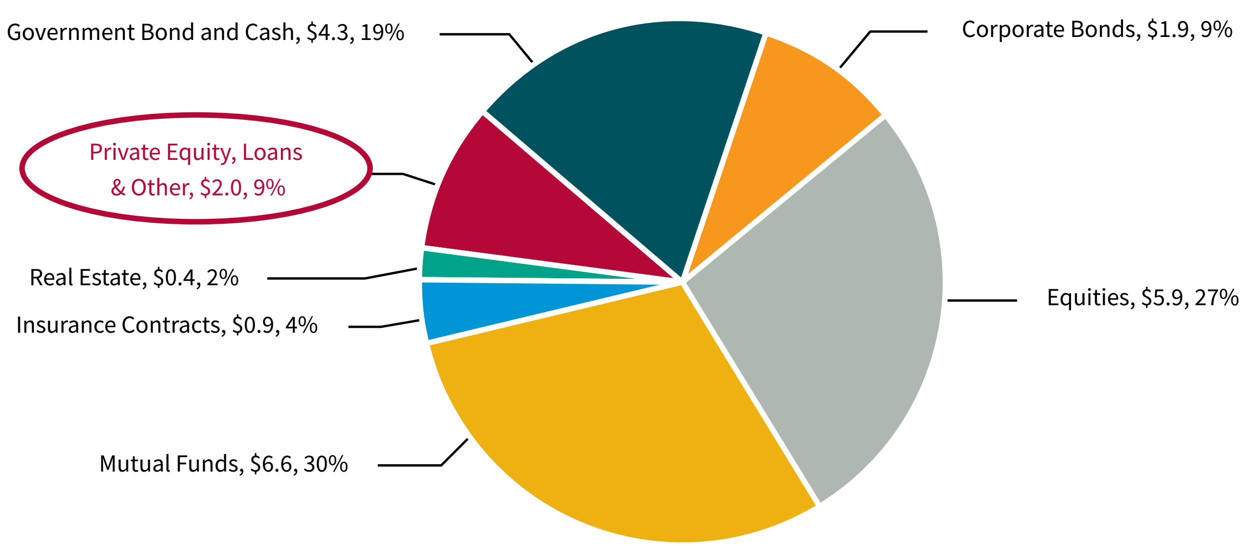


higher interest rates because of their higher credit risk. This category of low-rated "high-yield" bonds is used to finance higher-risk enterprises. Of that $241 billion total amount of high-yield bonds issued, $152 billion (2% of the bond market) was used to refinance old debts, thus leaving just $89 billion (1% of the market) for actual new investments by low-rated borrowers.[8]

Further complicating matters, the high yield/high-risk slice is unlikely to grow very much and as a result, we must reduce the risks in clean energy projects so that more of them appear on the lower-risk end of the risk spectrum. For most debt investors, there is not really a smooth risk/reward continuum, moving from ultra-safe to ultra-risky. It would be reasonable to expect that if an investor demands 3% rates for an AA-rated publicly traded bond, s/he might be happy to own a B-rated high-yield bond for a higher 7% rate. However, the rules by which most large institutional investors operate prohibit moving very far outside a narrow range of the risk/reward spectrum. Thus, insurance companies must meet standards set by state insurance commissions; pension funds are subject to lawsuits under the ERISA federal pension law if they are not "prudent", and a "high-grade bond fund" manager can't buy B-rated bonds. There is a similar dynamic in equity markets, i.e. no matter how high the promised returns on clean energy LLCs, institutional investors will be compelled to allocate a significant portion of their equity portfolio to low-risk "large-cap" blue chip stocks.

Global Pension Markets: Pension funds are especially relevant because they have been a major focus of advocacy for clean energy investment. As shown in Figure 4 below, pension funds put the vast proportion of their funds in traditional assets of cash, government bonds, investment-grade bonds, publicly traded stocks, commercial real estate, and mortgage-backed securities, and loans — a total of $22 trillion (91%) of the pie chart below. The $2 trillion (9%) red slice — "Private Equity, Loans & Other" — is currently invested in riskier *non-traditional asset* categories including private equity, hedge funds, infrastructure, etc.[9] Most new clean energy investment in the IEA 450 Scenario falls into this higher-risk non-traditional category, as explained above. Within the overall non-traditional category, pension funds designate a sub-class for "infrastructure," and then within that sub-class carve out a portion of infrastructure for "clean energy"

FIGURE: 4. Most Clean Energy Investments Fall Within ~ 9% Slice of Pension Asset Allocation ($billions)



or “green investments.” Based on responses to the OECD’s “Annual Survey” of pension fund asset allocations, representing about 1/3 of pension dollars,[10] approximately 1% of total assets are invested in “infrastructure,” with clean energy representing about 0.01% (1/100th of 1%) of total assets.

On a more hopeful note, as pension funds seek to increase earnings to make up for low current returns on stocks and bonds, the non-traditional slice above could grow and clean energy investments could claim a bigger piece of that growing slice. However, this would require pension funds to build stronger internal teams to make these kinds of investments at current risk levels. Even better, if the risks of clean energy investment were reduced then clean energy projects could compete across larger slices of the pension pie, e.g. investment-grade bonds, and listed shares.

Taken together, the U.S. bond market and the global pension market demonstrate that the securities sold within key portions of the global capital markets and held in the asset portfolios of institutional investors are primarily of high credit quality. This sets a high bar for clean energy projects.

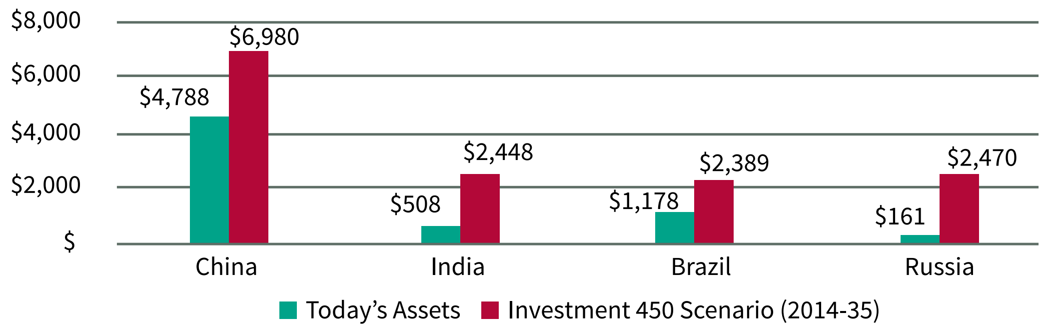
1.1.3 THE LOCATION PROBLEM — WHERE THE MONEY ISN’T

There is a third problem — the location problem — complicating the scale-up of global clean energy spending: the majority of the IEA’s forecasted capital investment to meet the 450 Scenario will have to be spent in non-OECD countries but most of the planet’s capital resides in OECD nations. If the need for clean energy investment capital in each country, rich or poor, were in line with its existing wealth or annually generated investible funds, then the problem would be less acute. However, the opposite is the case: a disproportionate amount of decarbonization spending is required in poor countries that haven’t amassed large pension funds, insurance accounts, or mutual fund holdings.[11] [12] Large amounts of foreign investment (FI) — providing debt and purchasing equity — will, therefore, be needed to fill this gap.

The IEA 450 Scenario projects that $900 billion to $1.2 trillion will be required annually between 2016 and 2040 for *non-OECD* spending on clean electricity and energy efficiency.[13] Four non-OECD countries known as the “BRICs” (Brazil, Russia, India, and China) — that accounted for 43% of world CO_2 emissions in 2015 — have a particularly significant mismatch between IEA forecasted decarbonization capital expenditures and their current investment assets. The IEA’s 2014 450 Scenario shows the BRICs spending $14.2 trillion by 2035 on decarbonization investments.[14] Figure 5 below shows this investment gap. In the aggregate, the need for decarbonization spending in the BRICs outpaces current investment assets by about $8 trillion, a gap that will likely have to be filled primarily by FI.[15] [16] And beyond the BRICs, the “needs versus wealth” equation is even more challenging in lesser-developed countries, especially where there is little or no access to modern energy.

One obvious answer is that multilateral development banks (MDBs) might be able to solve the location problem. Current lending data, however, suggests the opposite. For example, the World Bank made energy efficiency and renewable energy loans of only $4 billion per year between 2010 and 2016,[17] and the International Development Finance Club, made up of 23 other international development banks, is making similar loans at the rate of just $7 billion per year.[18] Another potential option is the Green Climate Fund established under the U.N. Framework Convention on Climate Change to help developing nations address climate change. The 2020 goal for the fund is $100 billion, but as of May 2017 just $10.3 billion had been pledged[19] and in June President Trump announced that the U.S. would stop paying into the fund.

FIGURE: 5. Investment Needs Bigger than Wealth ($Bn)



1.1.4 IMPLICATIONS FOR SUCCESSFUL DECARBONIZATION

Taken together, the quantity problem, the quality problem and the location problem leave us with a monumental challenge. We must triple global clean energy spending within an annual global pool of investible capital that is:

- Not much larger than the required need identified in the IEA's 450 Scenario;
- Largely allocated to investments that are far safer than most clean energy projects;
- Mostly held in OECD nations, while much of it will have to be spent in the developing world, with all the attendant risk.

Since it is highly unlikely that pension funds, insurance companies, mutual funds, sovereign wealth funds and billionaires will significantly lower their investment standards for climate reasons (assuming they even could) then the quality of the green investments offered must be improved.

Green energy projects must become blue chip investments, if we are going to successfully confront climate change.

One piece of good news is that unlike some other existential threats, e.g. nuclear proliferation, mitigating the climate problem carries with it a significant upside. Investment in new global energy infrastructure could well be the single greatest economic opportunity of the 21st century.[20] Global investment totaling $58 trillion[21] over the next 25 years in clean energy could bring with it major economic, security and health benefits. Importantly, many of these benefits will flow to the developing world. At the same time, there is no doubt a downside, from coal miners to oil drillers to gasoline station attendants who could lose their jobs. However, handled well, major employment opportunities should accompany the massive new spending the clean energy sector could see.

The other piece of good news is that the needs of the world's institutional asset owners[22] and the needs of the world's clean energy project developers are actually well aligned. Both institutional asset owners and clean energy project developers need to take a long-term view and require stable, predictable debt and equity payments. The owners of institutional assets are compelled to be long-term oriented because of the nature of their obligations to beneficiaries such as retirees with pension assets. At the same time, clean energy project developers also need to take a long-term view because of the nature of their industry. If clean energy projects can only borrow higher-cost short-term debt to fund long-term assets with 20-30 year useful lives, those projects won't be able to compete against traditional fossil projects and other kinds of investments with traditional long-term financing.

1.2 INVESTMENT RISK

The foregoing suggests an unprecedented challenge but also signals the essential point of leverage in solving it. If we are going to achieve anything close to the kind of spending required to address climate change, we need to "derisk" clean energy projects so that they become more attractive to major institutional investors. Only by fixing a broad range of investment risks that confront clean energy projects will we have a shot at scaling clean energy investment at a pace and to a level that is required. Looking through an "investor lens" we can see in clear focus the many risks that cause clean energy investments to fail. In Figure 6 we highlight four broad risk categories and, within each category, the specific investment risks that this paper analyzes.

FIGURE: 6. Risk Categories and Specific Investment Risks

Risk Category	Specific Investment Risks
Markets	Electricity Market Design
	Fossil Fuel Prices
Policy	Mandates & Carbon Pricing
	Government Subsidies
Project Development	Innovative Technologies
	Government Approvals & Permitting
Investment Framework	Rule of Law
	Tax Issues
	Debt Regulation, Equity Disclosure & Currencies

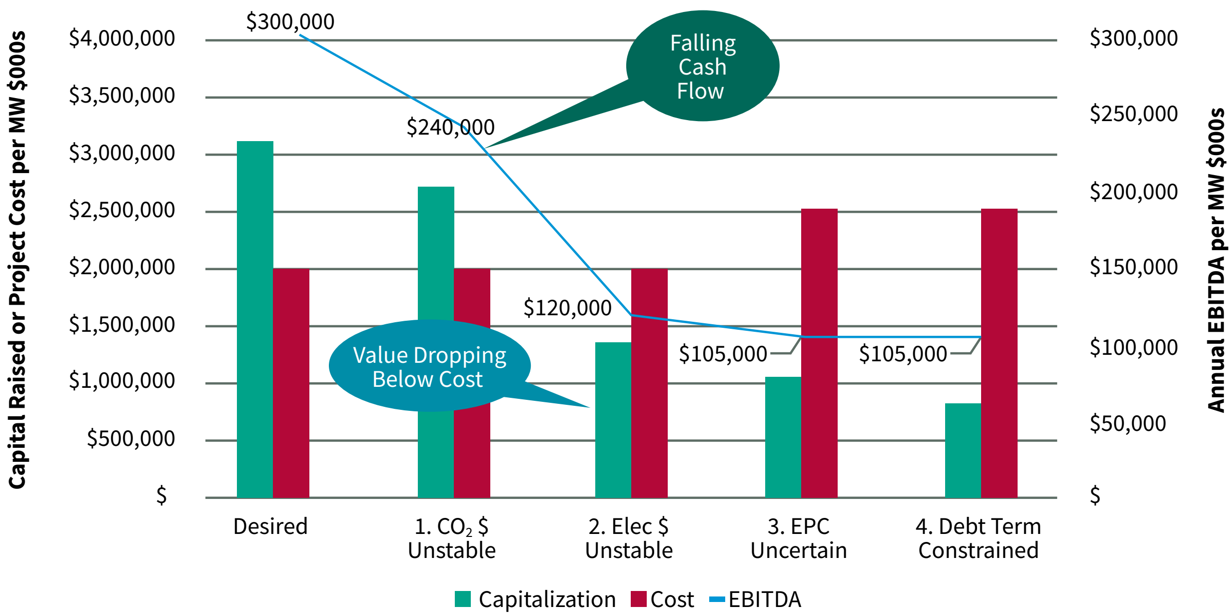
Some of the risks are market-based, e.g. volatility in the price of electricity and fossil fuels. These market risks will either affect the financial merits of a proposed clean energy project directly, e.g. the price a wind project can sell into a market, or indirectly via the economics of a competing incumbent energy source, like natural gas. Some of the risks flow from major policy decisions, e.g. the pricing of carbon emissions or the value of government subsidies. These risks will govern the overall economics of a proposed project, e.g. will a carbon price on competing fossil-based generation or a tax-related subsidy for the clean energy project be high enough (and reliable enough) to offset any cost disadvantages of a project on the drawing boards?

Some of the risks relate to the nuts and bolts of developing a project, e.g. securing interconnection contracts, transmission permits, or power purchase agreements, or addressing the uncertainties around an innovative technology in an engineering, procurement, and construction (EPC) contract. These types of risks will have a lot to say not only about the economics of a project but also about its pace. In project development time is money and delays can sink an otherwise attractive project.

And some of the risks are at the heart of the investment framework that sets the terms of a project deal: bank capital adequacy rules; "rule of law" considerations; general tax provisions etc. For instance, regulations developed to ensure adequate bank liquidity have made it more difficult to obtain long-term loans. And a weak "rule of law" in a country regarding contracts, bankruptcy or sovereign immunity can send investors scurrying.

Critically, the above risks often occur simultaneously in a project and their impacts may compound on each other i.e. three or four major risks may confront a project, the cumulative impact of which may be worse than the sum of their individual impacts. Figure 7 below highlights this situation where four risks – unstable CO_2 prices, unstable electricity prices, an uncertain engineering, procurement and construction (EPC) contract, and a constrained debt term – lower cash flow and raise project cost, thereby eroding capitalization (i.e., the "value" of the project).

FIGURE: 7. Four Risks Compound, Cash Flow Dives & Capitalization Falls



1.3 APPROACH TO THIS PAPER

This paper takes a preliminary look at risks in clean energy investment and potential solutions (subsequent phases of the Stanford initiative will dig deeper). We analyze the nine specific risks above answering several questions:

- What is the investment risk and how does it differ across geographies?
- What are some of the solutions to address this risk and barriers to their implementation?
- What are the next research steps?

Solutions might involve, for example: energy markets that better account for the benefits of particular energy resources; more effective pricing of carbon emissions or smarter clean energy mandates; and rule of law reforms, particularly in the developing world. In terms of barriers, a number of them — political, technical, capacity-related — stand in the way of implementing these solutions. In prioritizing efforts, we need to consider that some high-impact solutions may face insurmountable political barriers and some individually smaller-bore fixes may win broader support. In the U.S., for example, a nation-wide carbon tax may face long political odds while targeted changes to the tax code might be more viable.

Finally, the measure of success for a particular solution should be considered from multiple directions. The ultimate societal goal involves the most low-carbon energy produced and/or carbon abated per private and public dollar spent. An institutional investor's goal would be to obtain reasonable and stable risk-adjusted returns, while a policymaker might look for what is politically practical to adopt and also enduring over the long haul.

ENDNOTES – CHAPTER 1

1 https://www.iea.org/media/publications/weo/WEO2016Chapter1.pdf p.1.

2 Data from IEA's "World Energy Outlook 2016," Table 2.4 on p. 82, subtracting fossil fuel expenditures.

3 Some analysts describe the funding challenge as smaller. For instance, Bloomberg New Energy Finance (BNEF) and CERES explain that the challenge is increasing today's $277B/yr on renewable energy spending to $485B/yr in a 2-degree C scenario. That analysis does not include increasing today's $500B/yr on energy efficiency, electricity networks, and other low carbon sources (nuclear, CCS, etc.) to $1.8 T/yr, as projected by IEA. See "Mapping the Gap," January 2016, p.3. https://data.bloomberglp.com/bnef/sites/4/2016/01/CERES_BNEF_MTG_Overview_Deck_27January.pdf

4 As to investment flows we did not include banks because they primarily make short-term loans backed by short-term deposits. In order to make long-term loans, they need to raise long-term deposits from or sell securities to the institutional investors such as the pension funds, etc. already included in our calculations. https://www.federalreserve.gov/newsevents/pressreleases/bcreg20160503a.htm

5 Figure 2 has a mix of sources. Databases allow one to observe actual new investible funds for the OECD's pension contribution data and the mutual fund industry's mutual funds net sales data. For insurance companies, SWFs, and billionaires, data was only available for changes in assets controlled — a figure that includes the sum of new inflows plus appreciation of existing assets under management. Thus, the figures are likely to overstate the annual new amounts of money available. As a cross-reference, Boston Consulting Group showed $71.4 trillion of "Global Assets Under Management" by institutions in 2015 (vs. $100 trillion above), that had grown by $1.05 trillion 2014-2015 (versus our $1.7 trillion change above). https://www.bcg.com/publications/2016/financial-institutions-global-asset-management-2016-doubling-down-on-data.aspx

6 Figures such as the worldwide Gross Fixed Capital Formation of $19 trillion in 2015 (per World Bank data base) suggest larger quantities of annual investible capital. But that figure overstates the case because it includes replacement of worn out equipment, homes, streets, sewers, etc., and therefore it is the net investment figure that is relevant. Thus the World Bank estimated "net investment in non-financial assets" was 1.345% of World GDP in 2015.http://data.worldbank.org/indicator/GC.NFN.TOTL.GD.ZS. That percentage applied to 2015 World GDP of $74.51 trillion equals $1.0 trillion versus a gross of $19 trillion.

7 The IEA's 2014 World Energy Investment Outlook shows total fossil fuel production investments over 2014-2035 (21 years) of $19.2 trillion under the 450 Scenario (p. 42) and of $23.5 trillion under the New Policies Scenario (p. 29). The difference is $4.3 trillion, or about $200 billion per year. A higher figure could be obtained by comparing depressed 2016 fossil spending to the total fossil spending in the 450 Scenario as revised later in the 2016-2040 projections.

8 Source: SIFMA website. https://www.sifma.org/resources/research/bond-chart/ plus high-yield analysts' estimates on refinancing volumes.

9 OCED Pension database, with USD 2015 figures from tables at http://www.oecd.org/daf/fin/financial-markets/globalpensionstatistics.htm. The 9% / $2 trillion slice combines five small categories in which most proposed clean energy projects would fall: Private Equity ($7 billion), Hedge Funds ($0.5 billion), Loans ($160 billion), "Other" ($1,785 billion), and Unknown ($15 billion). Some very low risk clean energy investments would be included in Equities & Corporate Bonds.

10 "Annual Survey of Large Pension Funds and Public Pension Reserve Funds 2015." See Table 9 (p. 46) for infrastructure investments by fund, p. 49 for infrastructure as % total assets, and Figure 12 (p. 51) for infrastructure allocation by category.

11 Boxed quote from introduction to Project Report May 2014 for the OECD's project on "Institutional Investors and Long-Term Investment."

12 World Energy Investment Outlook 2014, p. 42, Table 1.6. 55% of non-fossil power spending and energy efficiency spending takes place in non-OECD countries.

13 $900 billion derived by taking BRIC's annual 450 Scenario non-fossil electric plus energy efficiency spending from IEA 2014 World Energy Investment Outlook, p. 42. The IEA boosted world-wide spending on these categories in the 450 Scenario by a factor of 1.7 over a longer 2016-2014 time frame (26 vs. 21 years). $900 x 1.7 x 21/26ths = $1.2 trillion.

14 The "Spending 450 Scenario" figures are from the IEA's to 2014 World Energy Investment Outlook p. 42 (Table 1.6). The figure would show a much more striking disparity between assets and spending if 2016 IEA figures had been broken down by country as they were in the previous 2014 report. That is because between 2014 and 2016, the IEA increased total investments needed in the 450 Scenario for decarbonization and energy efficiency by a factor of approximately 1.7x.

15 A better comparison would be annual spending needs vs. annual growth of investment assets in these countries (similar to the figures we used earlier in this Introduction) but that data was not available to the authors.

16 The investment assets are from the same sources as investment flow figures in the Introduction. For each country the amount shown is the sum of the IMF's "Table 15" All Economies — Reported Portfolio Investment Assets," sovereign wealth funds from the Sovereign Wealth Fund Institute, insurance company assets (cross checking OECD insurance assets and industry tables for world's largest insurance companies by assets), and mutual fund holdings from the Investment Company Institute's 2016 Investment Company Factbook (Section 8, Table 65).

17 http://www.worldbank.org/en/topic/energy/projects Accessed September 7, 2017.

18 "Mapping of Green Finance Delivered by IDFC Members in 2014," November 2015. A total of $40 billion was delivered for renewable and energy efficiency loans in 2014, but only 18% ($18 of $98 billion) of all green loans went from OECD countries to non-OECD borrowers, implying roughly $7 billion of RE and EE loans from OECD countries to non-OECD. https://www.idfc.org/Who-We-Are/members.aspx

19 Green Climate Fund, Status of Pledges.

20 https://www.iea.org/publications/freepublications/publication/WEIO2014.pdf

21 IEA 2016 World Energy Outlook p. 82, Table 2.4 (fossil energy figures subtracted out).

22 The investors who "run money" on a daily basis for the asset owners are typically short-term thinkers, because they have to beat other managers every quarter. We are talking here about entities that actually own the funds and have responsibility to meet their obligations to, e.g. pensioners and insurance beneficiaries.

Chapter 2: Market Risk — Electricity Market Design

A developer will only launch a project if there is a good prospect of obtaining a long-term stable agreement under which a project sells its electricity and/or "capacity"[23] to a credit-worthy customer. The jurisdictions that pose the greatest challenges in obtaining such agreements are often those that adopted competitive markets where power suppliers are typically chosen based on hourly energy auctions but also where certain clean energy sources are mandated in order to meet environmental goals. These hybrid systems — partly competitive, partly regulated — have increased development risks for many of the technologies in the IEA's 450 Scenario.

This chapter looks at current electric market design, the risks it poses to various clean energy project investments, with a brief consideration of potential solutions. The chapter uses California as an illustration.

2.1: INVESTMENT RISK

To assess the risks in electric market design, it is important to understand just how different the IEA's future path is from the road we have been following, particularly in the hybrid markets that make up much of the U.S. power grid. In Figure 8 below we highlight some of these changes.

- The changes in the composition of U.S. installed generation between 2004 and 2014 (left column) included: the shutdown of 14 GW of unabated fossil plants; the addition of 75 GW of wind and solar; and 6 GW addition in the broad category we call "non-intermittent low carbon."
- Meeting the IEA's 450 Scenario for the U.S. from 2014-2040 (right column) requires: the shut-down of 309 GW of fossil capacity; development of wind and solar at approximately triple the current annual rate (adding 595 GW); and development of 309 GW of non-intermittent low-carbon sources — the resources that saw little progress in the last decade, e.g. hydro, biomass, geothermal, concentrating solar power (CSP) (with storage), nuclear, and CCS.

FIGURE: 8. Historic vs. Forecast U.S. Capacity Changes (GW)

Historic vs. Forecast U.S. Capacity Changes (GW)		
	2014 vs. 2004 (actual per U.S. EIA)	2040 vs. 2014 (IEA 450 Scenario)
Unabated Fossil		
Coal w/o CCS	(11.0)	(297.6)
Gas and Oil w/o CCS	(3.4)	(12.0)
	(14.4)	(309.6)
Intermittent Zero Carbon		
Wind	58.6	286.0
Solar PV Utility	16.6	309.0
	75.2	595.0
Non-Intermittent Low Carbon		
Nuclear	(0.5)	37.9
Hydro (Dams and Pumped Hydro)	2.9	17.2
CSP with Storage	1.6	56.0
Coal w/ CCS	0.0	61.0
Gas w/CCS	0.0	86.3
Wood & Other Biomass	2.4	35.6
Geothermal	(0.1)	10.5
Marine	0.0	5.0
	6.3	309.4

Figure 8 suggests that to the extent we are closing down coal and gas plants without CCS — higher carbon but reliable — the IEA's 450 Scenario envisions, in part, a comparable, off-setting addition of reliable lower carbon resources. These projects are unlikely to be developed if discouraged by a jurisdiction's electricity market design. This chapter uses California as an illustration because of the state's large and complex electricity market.

Why are investment risks for developers of decarbonization projects particularly challenging in countries and regions that "deregulated" generation and formed "competitive markets"[24] and then re-regulated certain resources to meet environmental goals? These markets, as with any power grid, face a difficult optimization problem of generating electricity efficiently, maintaining reliability, cutting carbon emissions, all while holding electric rates as low as possible. We call this the "efficiency-reliability-carbon problem." In these hybrid jurisdictions, separate siloed entities are responsible for different parts of this triad and too often no single entity is responsible for the difficult trade-offs overall. As the California Public Utility Commission (CPUC) staff warned in a recent report to the commissioners: "[T]he siloed procurement structure created by governing statutes and policies makes it difficult to identify the most efficient and cost-effective solutions to grid integration [of low-carbon technologies]. . . . [P]olicies directing resource procurement should consider costs and benefits from a system perspective."[25] This warning has major implications for developers and investors in a broad array of clean energy projects under the IEA's 450 Scenario in many competitive markets. California provides a useful illustration:

- The California Independent System Operator (CAISO) ensures efficient generation through competitive spot power market auctions and "merit order dispatch." Resources are dispatched from lowest to highest price without explicit regard to carbon emissions but subject to rules that put RPS-based resources first. For developers and investors, this means a non-RPS zero-carbon resource can only run if it beats higher carbon resources purely on price.[26]
- The CPUC and CAISO share responsibility for reliability. CAISO sets reliability standards and CPUC approves contracts between generators that own high-reliability power plants and utilities. The procurement process seeks the most capacity for the cheapest price without regard to carbon. Since natural gas-fired generation is the cheapest source of high-reliability power, developers of these plants have an easy time securing long-term bilateral

contract under California PUC orders, with debt and equity returns assured by the monthly capacity-based payments. Developers of other types of low-carbon high-reliability projects have a harder time and thus California has had a growing fleet of natural gas-fired power plants.[27]

- The California Energy Commission (CEC), California Air Resources Board (CARB) and CPUC share the carbon reduction mandate. CEC monitors whether utilities have met their RPS requirements,[28] measuring electricity sold to customers with no regard to reliability. The renewable energy contracts themselves require CPUC approval and are competitively procured primarily based on energy price. Separately, the California Air Resources Board sets overall carbon emission limits and allocates carbon allowances to utilities. As a result of this price-based procurement, virtually all new California renewable generation (with the exception of a small amount of concentrating solar power or CSP) has been wind and solar P.V., tracking the U.S. as a whole. Developers and investors who have pursued other kinds of low-carbon projects have mostly failed (or didn't get started) because they either (1) were not covered by the RPS, e.g. CCS, nuclear, large hydro, pumped storage or (2) offered combinations of reliability and low-carbon attributes at somewhat higher prices (e.g., CSP with storage, geothermal, and biomass).

To understand the competitive landscape of RPS procurement, consider a utility mandated to contract for low-carbon renewable resources based on the lowest "Levelized Cost of Electricity" (LCOE), a metric that does not value reliability. On this measure, as shown in Figure 9 below, intermittent resources such as wind and solar P.V. will be procured. Geothermal, biomass, and CSP with storage are highly predictable and reliable, with capacity factors in the 85% range,[29] but no value is placed on these attributes in the procurement process. As a result, their higher LCOEs are not offset by their reliability value.

FIGURE: 9. Qualifying Renewable Resources

Qualifying Renewable Resource	LCOE Avg. ($/MWh)
Solar PV	$55
On-shore Wind	$47
CSP with Storage	$119
Geothermal	$98
Biomass	$93.50

The examples below from California and elsewhere show the extent to which, in the absence of a systematic approach to solving the efficiency-reliability-carbon optimization problem, electricity market design can be a major source of risk to developers and owners of certain types of projects:

- Biomass plants are not being built and old ones are shutting down in the U.S. because they cannot beat NGCCs[30][31] in providing capacity/reliability, and they cannot compete against wind and solar in supplying RPS-compliant energy if reliability is not valued.
- In California, the HECA project (Hydrogen Energy of California), an Integrated Gasification Combined Cycle (IGCC) power plant with CCS, failed in part because the company could not obtain a long-term PPA approved by the CPUC.[32] CCS doesn't qualify as renewable, there is no regulatory framework to permit a plant like HECA to claim carbon allowances, and CCS can't compete with cheaper natural gas plants (lacking carbon controls) in reliability procurement;
- California regulators approved the shutdown of the state's remaining nuclear power plants and nationwide a number of nuclear plants are facing decommissioning. While their capital costs were fully amortized, these zero-carbon plants in most states are not prioritized under RPS and hence must compete in spot power markets on price alone, particularly with natural gas units, with lower variable costs but no carbon controls;

- CSP power plants have faced many challenges in California and several proposed projects have been abandoned, including the Palen[33] CSP plant and three others proposed by BrightSource Energy to sell output to the Southern California Edison Company. CSP plants, if built with storage capacity, can shift solar energy from day-time surplus periods to meet night-time demand peaks. However, reliability has not been a key factor in California RPS procurement and California storage procurement has focused only on batteries.
- California regulators have considered two major pumped hydro storage facilities but neither has been built. One is a project known as LEAPS that sought to be "rate-based" as a reliability asset but was rejected by federal regulators in response to CAISO objections.[34] The Eagle Mountain Pumped Storage project seeks to integrate intermittent renewables in Southern California but has made little progress in a decade. Storage is greatly needed to integrate intermittent renewable resources, and, as noted above, the California PUC ordered utilities to acquire 1.3 GW of battery storage. However pumped hydro projects — that are not a renewable energy generator, a cheap capacity resource like natural gas generation, or a battery — have found no regulatory avenue by which to obtain a secure contractual revue stream.

2.2: SOLUTIONS

A recent IEA observation highlights two approaches to solving the problem above: "In 2016, 94% of global power generation investment was made by companies operating under fully regulated revenues or regulatory mechanisms to manage the revenue risk associated with variable wholesale pricing."[35] So most of the world did not adopt competitive markets in the first place — from India to Indiana. Moreover, many nominally competitive systems are really hybrids that insulate large sectors of generation from wholesale price volatility through fixed-price procurement for renewable energy under RPS and fixed-price bilateral contracts for capacity.

So one solution is re-regulation of these hybrid systems. That is, countries or regions with competitive markets might pull back and reestablish old ways of regulation. In so doing regulators would be admitting that the efficiency benefits of competition are outweighed by the challenges they create for decarbonization.

A second approach would be to enlarge the current carve-outs from competition to add more project types protected from competition. For example, RPS could be expanded to include:

- ***Wider resource types***. The term "renewable" in RPS does not correspond to "low-carbon" and the term usually excludes nuclear, carbon capture, and large hydro, all key resources according to the IEA. An alternative would create a "clean energy standard," as New York's Public Service Commission did when it adopted a "Zero-Emissions Credits" requirement.[36]
- ***Capacity as well as energy***. Instead of RPS being defined based upon the percentage of energy sold by a utility, it might also impose some type of low-carbon capacity mandate. This would give dispatchable low-carbon resources — both generation and storage — a way to monetize their most attractive attribute, i.e. capacity value.

A third approach would be to create a "shadow carbon price" that can be used to evaluate prices bid by generators on a carbon-adjusted price per MWh basis, rather than the raw bids alone.[37] An alternative version of this idea is the Carbon-Linked Incentive for Policy Resources (CLIPRS) that would provide an extra payment to zero-carbon generators based on their carbon intensity.[38] Instead of penalizing emitters, CLIPRS would reward non-emitters.

ENDNOTES – CHAPTER 2

23 A power project has two products to sell: first, the actual energy output measured in megawatt hours; second, capacity measured in megawatts which is a customer's ability to order a plant to operate in support of reliability.

24 In countries or subnational regions with government-owned power monopolies or state-regulated, vertically integrated investor-owned utilities, the issue of "electricity market design" does not generally pose significant risk to developers or investors.

25 "Beyond 33% Renewables: Grid Integration Policy for a Low-Carbon Future," CPUC Staff, November 25, 2015, page 14.

26 When bidding into the CAISO spot market, fossil fuel resources must buy carbon allowances, but because these allowances are cheap (e.g. $5 per MWh for a natural gas NGCC plant) they generally don't confer meaningful competitive advantage to zero-carbon resources.

27 Note that in 2013 California required utilities to buy 1300 MW of battery storage. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M078/K929/78929853.pdf No other storage assets have been approved.

28 California also has a cap-and-trade system mandated by AB32, but the primary driver of carbon reduction has been RPS. Utilities are given large allocations of free "allowances" that they sell to the generators that supply energy, and the actual allowances have been trading at minimum price floors of ~$13/MT for a number of years.

29 Capacity factors and LCOEs from "Lazard's Levelized Cost of Energy Analysis — Version 10.0," December 2016, pp. 18-19. The 85% capacity factor for CSP assumes a concentrating solar tower system with 18-hour storage capability, per Lazard.

30 "Solar Is In, Biomass Energy is Out — and Farmers are Struggling to Dispose of Woody Waste," *LA Times,* December 15, 2015.

31 http://www.energy.ca.gov/almanac/electricity_data/electric_generation_capacity.html

32 Prospects were also harmed by lack of a regulatory regime that would permit the project to earn Allowances under California's Cap-and-Trade system — a separate process administered by CARB.

33 "Five Hundred MW Palen CSP Project in California Cancelled," October 5, 2015, *Clean Technica*.

34 Pumped hydro, and all hydro facilities on "waters of the United States" are licensed by the Federal Energy Regulatory Commission, but in this case FERC rejected the business plan in its role as overseer of the CAISO.

35 IEA World Energy Investment 2017, pp. 106-107

36 State of New York Public Service Commission, "Order Adopting a Clean Energy Standard," issued August 2, 2016.

37 Electricity Market Design and Carbon Capture Technology: The Opportunities and the Challenges," white paper prepared by State CO_2-EOR Working Group, June 2017, p. 32. Available on Great Plains Institute website at http://www.betterenergy.org/publications/electricity-market-design-and-carbon-capture-technology

38 "Pre-filed Comments of Robert B. Stoddard" FERC Docket No. AD17-11-000. Mr. Stoddard testified on behalf of the Conservation Law Foundation.

Chapter 3: Market Risk — Fossil Fuel Prices

While nations often regulate prices and competition in electric markets, they tend to have little control over fossil fuel prices. From the perspective of a clean energy developer or investor, fossil fuel prices pose two related challenges: low price and substantial volatility.

This chapter looks at the specific situations where low fossil fuel prices and/or significant price volatility pose risks to clean energy projects and some of the solutions that might address these challenges.

3.1 INVESTMENT RISK

Low fossil fuel prices affect many low-carbon investment opportunities, as summarized in Figure 10:

FIGURE: 10. Decarbonization Projects and the Risks Posed by Low or Volatile Fossil Prices

Decarbonization Projects and the Risks Posed by Low or Volatile Fossil Prices	
Decarbonization Projects	Fossil Price Exposure
Renewable power projects	Low natural gas prices make natural gas combined cycle plants more attractive
Storage projects to integrate renewables	Low natural gas prices make natural gas peaker plants cheaper
Replacement of coal plants with natural gas plants	Low coal prices hurt replacement
Hydrogen production through electrolysis powered by renewables	Cheap natural gas in steam methane reforming undercuts lower-carbon electrolysis alternative
Electric vehicles and assembly plants	Low gasoline prices make electric vehicles and manufacturing less competitive with incumbents
Production of less carbon-intensive light oils (API >30)	Cheap natural gas encourages production of tar sands/heavy crudes with higher carbon intensity
Coal gasification with carbon capture	Low natural gas prices make power less competitive; low oil prices hurt CO_2 sales for enhanced oil recovery operations

If, as some believe, solar and wind have now reached "grid parity," then fossil prices would not be such a risk. However, while solar and wind equipment costs have dropped substantially, serious competition remains from a fleet of already-built, highly efficient natural gas combined cycle (NGCC) generators that, in the U.S., are only running at 45% capacity factor nationally.

As shown in Figure 11, the cash operating cost of an *existing* NGCC at $20/MWh is less than the life-cycle cost to build a new wind ($32/MWh) or solar PV ($49/MWh) project.[39] The comparison would be more favorable for solar and wind in the case of a new NGCC ($48/MWh). The lower the cost of natural gas, the higher the incremental cost of the clean project, and the higher the marginal cost of reducing CO_2 by pursuing the zero-carbon option. Of course, a meaningful price on carbon emissions could change this equation and a renewable portfolio standard set it aside.

FIGURE: 11. "Grid Parity"

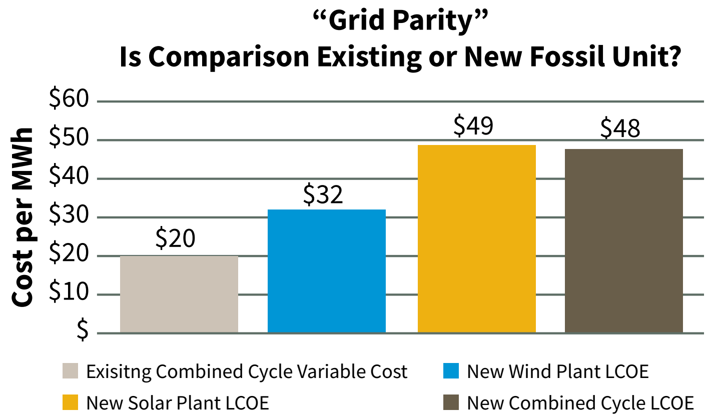
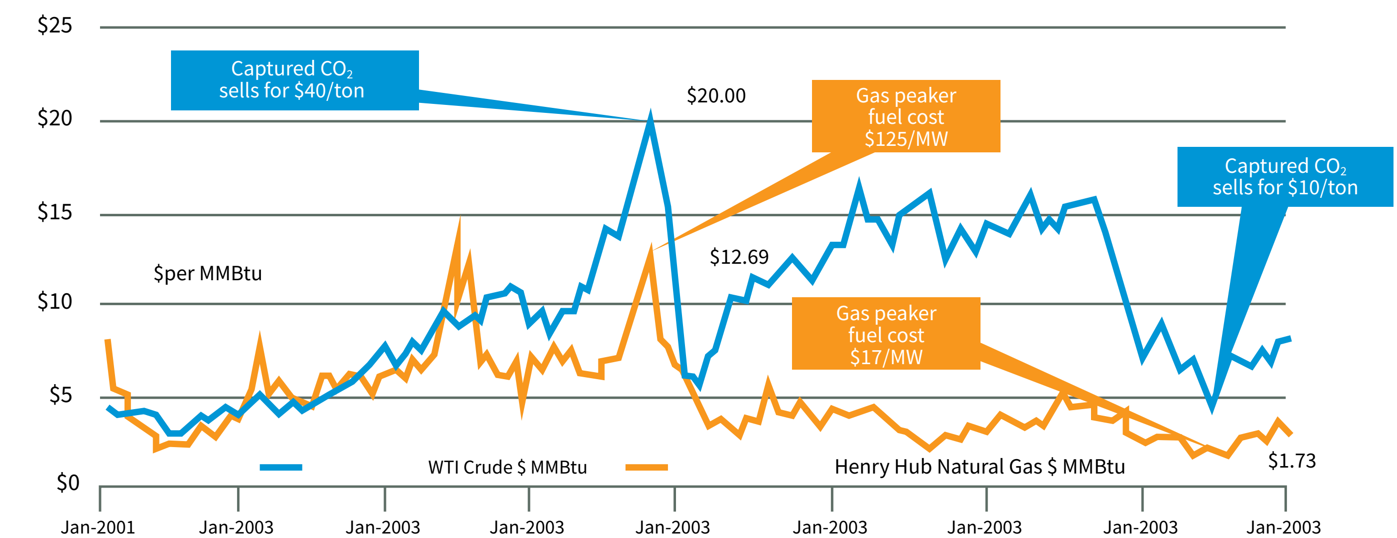


Figure 12 below provides a real-world snapshot of how volatility in fossil fuel prices might affect two types of projects: (1) an electricity storage project competing with natural gas peaking generators (blue) and (2) a carbon capture facility competing with the status quo of unabated emissions (orange). A storage project is attractive with natural gas at the 2008 price, resulting in gas-fired electricity costing $125/MWh. The opposite is the case when natural gas prices fall to about 15% of the 2008 peak, as they did in 2016. At peak oil prices in 2008, the CO_2 obtained from adding carbon scrubbers to a power plant could sell for $40/ton, at which point CCS projects become attractive. That would not be the case with 2016 oil prices at 25% of that peak.

The investment risks posed by fossil fuels prices are driven both by *absolute price levels* (high or low) and *volatility* (steady or fluctuating significantly). The risks can be expressed either in difficulties of reaching financial closing of a project investment, or the possibility of financial distress once a project is operating. Of course, if a project could lock in or "hedge" fossil prices in the futures markets, neither

FIGURE: 12[40]. Oil and Natural Gas Prices - Impact on CCS and Natural Gas Power Plants



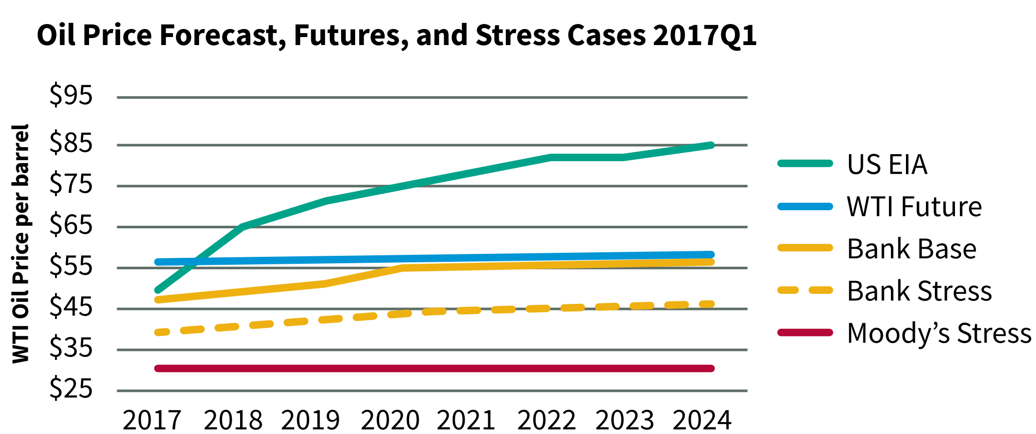
the absolute price level nor the volatility of fossil fuel prices would be a serious problem. However, gas and oil futures markets are quite illiquid more than five years in the future, versus a typical energy project's need for a stable earnings pattern for roughly two decades in order to service debt.

Low-carbon projects have greater financial viability at *higher absolute price levels* of fossil fuels. At higher prices, the penalty for switching from a CO_2-emitting activity to a clean activity is lower. Confidence levels are also higher, since when "spot" fossil fuel prices are high today, expert forecasters tend to project a continuance of generally high prices, and fossil fuel futures prices are anchored on the high current spot prices.[41] In such an environment it is easy to gain public support, government subsidies, and output contracts in support of clean energy projects. On the other hand, when fossil fuel prices are at low absolute price levels, the penalty for switching to a clean activity is high, most forecasters project continuing low prices, and futures prices are anchored on today's depressed spot prices.

With high fossil fuel price *volatility*, a more-subtle, lender-related problem emerges. Volatility is the statistical measure of the likelihood of extreme price changes. For a project or company that is highly leveraged with debt — as decarbonization projects often need to be — performance can be strong for a decade, and then a single extreme year of low fossil fuel prices might cause a debt default and bankruptcy. In contrast, volatility is not as great a problem for a project or company financed mostly by shareholders (i.e. equity) that has little debt.

Volatility makes it harder for clean energy developers to borrow project funding. Because fossil fuel prices are inherently volatile for political, technological, and macroeconomic reasons, lenders are dubious of rosy fossil fuel price projections. Figure 13 below depicts five views of the oil market as of first quarter 2017, with U.S. EIA forecasting West Texas Intermediate (WTI) oil rising back to $85/bbl (green) and the oil futures market pricing it in the mid-$50s/bbl (blue). However in order to satisfy Moody's credit rating standards — and thus to garner precious investment-grade ratings on long-term bonds — a project borrower has to show it can survive $30/bbl oil (red line). If a borrower can't meet that $30/bbl rating stress test, it may need to seek shorter-term financing from banks whose "Base Case" starts out at a 15% discount to futures (solid yellow line) and whose "Stress Case" starts at a 30% discount to futures (dashed yellow line).

FIGURE: 13[42]. Oil Price Forecast, Futures, and Stress Cases 2017Q1



The conservative assumptions used by lenders and rating agencies limit borrowing capability and thus raise overall project capital cost. Using the EIA oil prices above a project might be able to use a mix of 60% debt and 40% equity, generating a blended financing cost of 8%. But if the debt is limited to the amount the company can service at $30/bbl — the stress case — the project may end up with 30% debt and 70% equity, generating a blended financing cost of 11.5%.

3.2 SOLUTIONS

The fundamental risk of low and volatile fossil fuel prices for clean energy projects seems quite intractable, but several solutions have been advanced, although none are necessarily easy.

A high and stable carbon tax would, of course, both raise the price of and reduce the volatility of fossil fuel prices. For example, a barrel of oil when consumed emits approximately ½ MT of CO_2. So in a world of $50/bbl oil, a $50/MT carbon tax (or $25/bbl) would raise the price of the barrel to $75/bbl. It would also introduce a non-fluctuating $25 element into oil pricing, reducing the percentage, if not absolute dollar volatility. This wouldn't fully stabilize fossil prices, but it would make project sensitivity cases less challenging.

Another idea floated legislatively in the U.S., is to stabilize fossil fuel prices for projects that are sensitive to such prices by authorizing the U.S. government to act as a long-term hedging counterparty.[43] This is similar to the U.K.'s Contracts for Differences (CFD) in the power market as described below in Chapter 5 (Government Subsidies). The budget impact might be beneficial because the commodities risk exposure to the government is exactly opposite of the U.S. government's current exposure. Today, the U.S. government is a major oil consumer in operating the largest transportation fleet in the world on land, sea, and air (260 million bbl/yr[44]) and is thus *hurt* by rising prices and *helped* by falling prices. A clean energy project typically has the opposite position of the U.S. government, i.e. the clean energy project is *helped* by rising oil prices and *hurt* by falling prices. The legislative proposal is to transfer this exposure to the U.S. government in a hedging contract using a CFD. The combination of the government's normal exposure (hurt by rising oil) with its position in the hedging contract (helped by rising oil) is more stable because the two exposures tend to cancel each other out. The government could also offer a CFD on natural gas prices. A green project competing in spot electric markets, with those prices influenced by natural gas prices, would be less risky if it had a contract in hand that paid it when natural gas prices dropped and vice versa.[45]

ENDNOTES – CHAPTER 3

39 NGCC $20 per MWh for an existing plant assumes a 7,000 Btu/kWh Heat Rate, $2.50/MMBtu natural gas price (USEIA 2016 average), and a $2.50 variable O&M cost. Other figures are low end of range for LCOE for Lazard's Levelized Cost of Energy Analysis-Version 10.0, December 2016, "Unsubsidized Levelized Cost of Energy Comparison" p. 2. On-Shore Wind at $32-62/MWh (the low number assumes a 55% net capacity factor) and Solar PV-Crystalline Utility Scale at $49-61 (the low number assumes a 30% net capacity factor). Lazard new build NGCC numbers are $48-78/MWh using a $3.45/MMBtu long-term natural gas price.

40 USEIA historical oil (WTI) and natural gas (Henry Hub) price series plus authors' calculations for natural gas peaking plant cash costs and CO_2 sales revenues.

41 Many people have the impression that oil or natural gas futures prices (i.e., the price at which one can contract to sell or buy oil or natural gas in, e.g., five years) are in some measure the market's "forecast" of prices." Instead, the prices are driven primarily by physical factors such as cost of storage (I can buy a barrel of oil today, pay to keep it in a tank, and deliver it in five years) and simple market dynamics between buyers and sellers (futures prices often trend downward because there are ample natural forward sellers such as over-leveraged oil producers, but few natural forward buyers).

42 Data from US EIA Annual Energy Outlook; Macquarie-Tristone Energy Lending Survey http://static.macquarie.com/dafiles/Internet/mgl/com/energy-ad/publications/energy-lender-price-survey/2017Q1.pdf?v=2 ; Moody's website https://www.moodys.com/research/Moodys-maintains-range-bound-oil-price-band--PR_362810; and WTI futures strip accessed on line for first quarter 2017.

43 Provisions contained in bipartisan Senate Energy Committee draft energy bill 2016 (S.2012- North American Energy Security and Infrastructure Act of 2016), Senate Engrossed version of 4/20/2016 in Section 3404 "Report on Price Stabilization Support."

44 DOE AER September 2012, Table 1.13.

45 According to trade press, Texas wind farms have sometimes used hedges that protect against falling gas prices to indirectly hedge against falling spot electricity prices in ERCOT. See "On the Rebound: Merchant Wind Projects Becoming Popular Alternative for U.S. Off-take Agreements," August 18, 2015, on North American Windpower website. http://nawindpower.com/on-the-rebound-merchant-wind-projects-becoming-popular-alternative-for-us-off-take-agreements

Chapter 4: Policy Risk — Mandates and Carbon Pricing

Mandates (including deployment targets and technology standards) and emissions pricing (including taxes and cap-and-trade) are two of the main tools governments use to guide clean energy investment without drawing substantially on public funds. Analysts have long argued over the relative merits of these tools: mandates are generally seen as effective but relatively expensive, while pricing is more economically efficient but less tested.

This chapter considers clean energy mandates and emissions pricing in terms of their impact on potential clean energy investments. Given that these tools are already intended to motivate clean energy investment, the chapter analyzes the comparative risks they present, and how these risks might be mitigated.

4.1 INVESTMENT RISK: MANDATES

Mandates are intended to create market demand that may not otherwise exist, generally through a government obligation of a regulated off-taker such as an electricity distributor, fuel blender, or manufacturer/installer of energy-consuming goods. Mandated demand for a clean energy project tends to increase the price which buyers pay for a given product versus conventional substitutes. Below we consider two kinds of mandates: the first for mature, but commercially non-competitive technologies and the second for experimental or otherwise non-market-demonstrated technologies.

Mandates for mature technologies are generous to developers but can stifle competition*. A project developer delivering a mandated — and essentially matured — technology, is presented with an attractive investment situation: the project has improved off-take certainty since contracts can be structured around the existence of the mandate, likely improved cash flow versus other technologies in the market, and often a known market size.*

But the same attributes that make mandates attractive for developers whose projects or technologies qualify can make the overall market in which the mandate exists worse for competing but potentially transformative, energy investments. Mandates like RPS reduce the addressable market for competing technologies, and they can be a costly approach. The California RPS, for example, has been estimated to deliver carbon dioxide emission reductions at costs of over $270 per ton,[46] with rooftop solar net metering specifically estimated by the state to cost $903 per ton.[47] These mandated options compare with alternatives like energy efficiency, industrial process shifts, or demand response that might cost less than $50 per ton.[48] In particular, in a system that primarily relies upon mandates, with market-based mechanisms being viewed as secondary, most of the emission reductions will be accomplished by the mandates, driving down demand for and prices of carbon allowances.

Mandates are less effective for early-stage technologies if not credible. Turning to the second kind of mandate, if conventional quota-based mandates carry with them the risk of hurting other investments, what about mandating less-proven desirable technologies? The major challenge with such mandates is that they may be seen as not credible. This could occur:

- If the mandate is widely viewed as technologically infeasible;
- If the mandate timelines are viewed as too aggressive so as to be unobtainable with reasonable effort;
- If the mandate does not enjoy broad government support and could be overturned with political cycles;
- If the mandate's market impacts create significant negative externalities for other assets or businesses;
- If the realized costs of the mandate are seen as excessive given the benefit; or
- If complementary financing and incentive schemes do not exist to facilitate achievement of the mandate.

California's 2009 Low Carbon Fuel Standard (LCFS) illustrates how mandates may be so aggressive as to invite survivability concerns that could turn off potential investment through elevated off-take risk. Under the LCFS, motor fuel distributors must blend an increasing percentage of advanced biofuels so as to reduce the overall carbon intensity of statewide gasoline and diesel sales by approximately 10% by 2020. Biofuel technology development did not meet government expectations; meanwhile, crude-based fuel prices fell.[49] By 2012, essentially no cellulosic ethanol was being produced at scale, which led to substantial legal challenges by obligated entities, a policy freeze, and a series of proposed reforms.[50] Meanwhile, the secondary market for tradable credits under the mandate — a proxy for potential additional revenues created by the mandate for potential new investors in this space — remained quite volatile, swinging month to month between lows of $17 to highs of $122.[51]

While the LCFS policy was eventually modified,[52] investment levels have fallen far behind initial government expectations of building more than two-dozen advanced biofuel refineries in the state by 2020.[53] California's experience here echoes the state's earlier attempts to mandate the use of M85 methanol in motor vehicle fuel.[54]

4.2 POTENTIAL SOLUTIONS: MANDATES

As a theoretical matter, mandates are more credible — considering both feasibility and social cost — when they are used to shore up achievement or deployment of mature technologies in lagging jurisdictions to levels already achieved by similar jurisdictions elsewhere. Consider, for example, Japan in its well-regarded "Top-Runner" program for the manufacture of energy efficient consumer goods: best performers are rewarded, but the overall standard is only increased through a stakeholder process as the viability of high-performance products and techniques is demonstrated in the marketplace. This program has now been in place for nearly three decades.

As a US-based example, an RPS mandate may be a more effective tool when used by states at lower deployment levels to support moving towards average target levels, e.g. from 10% to 20%. Of course, in the U.S. federalist system states of all political stripes have typically had significant authority to chart their own paths in areas like this and have done so for decades. For those who wish to use mandates more aggressively, using cost-minimization mechanisms such as reverse auctions, broadening the eligibility of covered technologies, and identifying and internalizing any cost shifts incurred by the mandate can help maintain political support.

Finally, the use of mandates should be limited — even for mature technologies — where mandates would overlap with concurrent broader clean energy investment incentives such as a carbon price. A "complementary" policy model may reshuffle available capital towards politically-preferred investments, and in doing could reduce average decarbonization effectiveness per dollar invested.

4.3 INVESTMENT RISK: CARBON PRICING

Whereas government subsidies or the mandates described above represent "out-of-market" interventions that attempt to incentivize particular types of clean energy investment, broad-based emissions pricing policies instead use existing market structures while nudging collective capital deployment in desired directions.

A broad literature has described the ways in which carbon taxes or cap-and-trade systems can be designed to minimize economic inefficiencies or administrative costs, compensate particular groups, or collect and redistribute public receipts.[55] These tools are becoming increasingly popular: as of 2013, 40 countries and another 16 states or provinces around the world priced carbon dioxide emissions, collecting over $28.3 billion in government "carbon revenues" in the process. Seventeen new pricing systems were implemented in the years 2007 through 2014 alone.[56]

But how does an investor view such policies? At a high level, a decision to implement carbon externality pricing signals that a jurisdiction has solidified the political support to make low-carbon investment an underlying goal of their economic development. This reduces the risk that capital investments might find themselves stranded due to changing political winds and moves clean energy projects towards the front of the queue to potential off-takers looking for new contracts or infrastructure acquisitions.[57] In fact, most carbon pricing systems have gradually increased their impacts over time.[58]

In terms of individual low-carbon investments, the effect of carbon pricing is to increase potential net revenues. But carbon pricing also introduces a number of new risks as to exactly what that positive impact will be over time.

Carbon pricing form affects predictability. First are the differences in risk associated with cap-and-trade versus carbon tax pricing regimes. Both are broadly beneficial to clean energy investors in that they are non-discriminate, especially if the market is "doing most of the work" in the presence of potentially overlapping deployment mandates as described above. While cap-and-trade or carbon tax schemes can both be designed to operate similarly from a macroeconomic perspective, investor differences can nonetheless persist. For example, like mandates, cap-and-trade systems require regulator foresight on complex variables — e.g. economic growth, energy demand, and the availability of competing technologies — in order to maintain a stable price signal over time.[59] When regulators fail to forecast these variables accurately, the impact of the carbon price may drop (as in California's AB32 cap-and-trade market following the 2008 recession) or the rules of the market may be changed to meet political goals (as with allowance allocation adjustments in the EU ETS). Contrast this with a carbon tax, which has more predictable price certainty and therefore lower risk of government abrogation.

Adding hard price collars to cap-and-trade systems can help mitigate this weakness, but it does not solve it. While a policymaker may expect clean investments as a whole to adjust smoothly over a range of cap-and-trade permit prices, any one project can likely only depend on — and therefore secure debt financing against — the carbon price being at its floor over the lifetime of that project. Equity investors may reap upside profits if the carbon price were to unexpectedly rise, but that would not necessarily motivate additional overall investment, especially from pools with low-risk tolerances.

Carbon pricing impact is affected by market dynamics. A related risk for both pricing schemes is that even if the government-created carbon price itself is consistent, its revenue benefits to a clean energy investor depend upon variables that are outside the investor's control, for example, the carbon intensity of a regional electric grid. A $20 per short ton carbon price would increase costs for a supercritical pulverized coal plant by around $17.50 per megawatt-hour and by about $8.00 for a natural gas combined cycle plant. Therefore, for a new zero-carbon generator in the PJM market,[60] such a carbon price might increase revenues on the order of 50 percent given the existing generation mix. For example, a typical nuclear power plant could expect additional revenues of $120 million in the first year. Those additional revenues, however, would fall over time if the carbon price caused decarbonization of that regional grid, such as a shift from coal to gas-fired generation. The value to an individual investment of a carbon price is reflected primarily in the future behavior of its competitors.[61]

Carbon prices can be muted by "complementary" regulatory mandates. Finally, there is the matter of carbon pricing policies interacting with government interventions such as mandates. Economists have recognized that the existence of a mandate — a renewable portfolio standard for example — alongside a broad carbon price such as a cap-and-trade system does not increase overall clean energy investment. Rather, the mandate simply shifts investments towards (generally higher-cost) chosen sectors or technologies, and in the process increasing overall social costs of decarbonization.[62] From an investor perspective, overlapping mandates and pricing policies can mean higher profits when investing in the mandate-favored sector. Non-mandated (but still carbon-priced) investments, meanwhile, may still enjoy revenues in excess of baseline expectations, but nonetheless, suffer capital flight toward more favored sectors.

Market structure allocates carbon pricing risk. Cutting across all of these is the issue of market structure, for example in electricity markets. In broad terms, traditionally regulated markets transfer business risk away from a project developer and onto customers or society at large once an investment is approved. In competitive generation markets, risks remain with the new project developer or investor (unless separately hedged). This has led to criticism that competitive markets will increasingly struggle to meet increasingly ambitious social goals or provide attractive investment opportunities alongside their basic charge to deliver cost-efficiency.[63]

For example, even given a cap-and-trade system or carbon tax, the added incentive for new clean energy investment in a competitive market is essentially limited to the lowest expectation of future conditions given the chances of policy change or simply of market shifts that change a completed project's competitive landscape. Compounding this is the fact that if a cap-and-trade system is changed once already in effect, the competitive project investor likely has no legal recourse against the government for the impacts to his or her now-“stranded” asset.

In a traditionally regulated market, however, the same carbon price signal can be more easily considered at its *expected* rather than *minimum* value over the lifetime of the project if accepted by regulators for approval. Moreover, an investor with an affirmative decision gains a counterparty with a legal obligation, which can be translated into other contractual agreements and used to secure better financing terms.[64]

While the relative merits of different market structures can still be debated given broader social interests, the narrower purposes considered here of reducing investor risks at a time when more investment is socially desired would seem to favor traditional markets. Anecdotally, recent efforts by North American electric utilities to shed competitive generation assets in favor of regulated infrastructure — and sagging competitive generator profitability and stock prices amid cheap natural gas and low demand growth — appear to support this view.

4.4 POTENTIAL SOLUTIONS: CARBON PRICING

Of the risks identified above, the first relates to volatility in the additional cash flows clean energy investors can actually expect over a project’s lifetime. To the extent that market prices vary because the price on carbon itself changes unpredictably over the lifetime of an investment — as has been observed in some weakly-constrained emissions cap-and-trade markets — then the use of more stable carbon prices (i.e. taxes rather than cap-and-trade) may be justified.

In the case of declining project revenues over time due to broader decarbonization, many proposed carbon tax designs suggest pre-determined schedules to gradually increase the pricing level every year or every five years. While there are broader economic justifications for such an escalation mechanism, it would also seem to be beneficial from a project investor perspective. Unknown system dynamics under a carbon price are also a good argument for prudency in the gradual implementation over time of any pricing system (as used to good effect in British Columbia with the five-year incremental roll-out of their provincial carbon tax) over a more abrupt approach, as used in Australia. The public- or private-led development of investor and consumer-friendly simulation tools during that ramp-up period could help affected parties better plan for and anticipate potential system dynamics before they actually face them.

Finally, as to overlapping market (e.g. pricing) and out-of-market policies (e.g. mandates), the best answer is likely to keep things simple. A “complementary measure” belt and suspenders approach might make policymakers feel as though they are doing more to pursue decarbonization, but this generally does not effectively deploy additional capital.[65]

ENDNOTES – CHAPTER 4

46 Adam Diamant, 2013, "Exploring the Interaction Between California's Greenhouse Gas Emissions Cap-and-Trade Program and Complementary Emissions Reduction Policies." EPRI.

47 See p. F-34 of Appendix F "Compliance Pathways Analysis" of the 2008 AB-32 Scoping Plan, which shows the State's calculation of the California Solar Initiative at $903 per ton.

48 CARB "Proposed Regulation to Implement the California Cap-and-Trade Program" Part I, Volume 1, p. V-12 shows the CARB staff's carbon abatement curve, with numerous options in the sub-$100 per ton area.

49 Whereas state regulatory staff originally estimated that the mandate would create a market for advanced biofuels at prices equal to or no more than 15 percent above conventional gasoline and diesel -- about $2.70 per gallon (CARB, 2009, "Proposed Regulation to Implement the Low Carbon Fuel Standard."; CARB, 2010, "AB32 Scoping Plan Updated Economic Analysis) — fuel producer KiOR estimated that its "scaled" cellulosic ethanol production cost in 2013 would actually be $5.95 per gallon (KiOR, 2012, "Q4 Earnings call."). KiOR declared bankruptcy in 2014.

50 These reforms, for example, included the development of a "safety-valve" cost cap for obligated off-takers, which while reasonable as a cost-containment mechanism from the government's perspective, essentially amounted to a tax on off-takers while not helping to improve the investment environment for new clean fuel suppliers.

51 CARB, January 2014 - July 2017, "LCFS Credit Trading Activity Monthly Reports."

52 CARB, October 2015, "2015 Re-Adoption of the LCFS Program."

53 CARB, 2009, "Proposed Regulation to Implement the Low Carbon Fuel Standard."

54 Jeremy Carl and David Fedor, 2014, "More Simplicity, Less Charisma: Improving the Effectiveness, Cost, and Fairness of California's Climate Agenda."

55 For a recent survey, see for example *Implementing a US Carbon Tax: Challenges and Debates*, edited by Ian Parry, Adele Morris, Roberton C. Williams III. 2015. Routledge.

56 Jeremy Carl and David Fedor, May 2016, "Tracking Global Carbon Revenues: A Survey of Carbon Taxes vs. Cap and Trade in the Real World." *Energy Policy*.

57 Australia's aborted carbon tax scheme stands as one exception to this observation, though it is notable that Australia's policy was implemented over loud opposition party dissatisfaction and was also the most ambitious — as measured by per capita carbon revenues — such policy globally.

58 Global carbon pricing systems have generally increased impact over time by expanding the scope of their coverage of the economy (e.g., California, Scandinavian countries), intervening in the market to increase the value of cap-and-trade emission permits (European Union, US Regional Greenhouse Gas Initiative), or increasing the rate of a carbon tax (British Columbia, Switzerland, Japan, France, UK, and Scandinavian countries)

59 Michael Wara, 2015, "Instrument Choice, Carbon Emissions, and Information." *Michigan Journal of Environmental & Administrative Law* 4(2).

60 The average wholesale electricity price in the U.S. PJM electric market was $29.23 in 2016.

61 Similar dynamics could be expected in other sectors as well -- for example the relative attractiveness to consumers of hybrid gasoline-electric vehicles versus full electric under a regime of higher gasoline prices, given that market share is here is dominated by conventional drivetrains.

62 Jeremy Carl and David Fedor, 2014, "More Simplicity, Less Charisma: Improving the Effectiveness, Cost, and Fairness of California's Climate Agenda."

63 Texas's full retail market being one notable exception. For one recent perspective on this tension see Travis Kavulla, May 2017, "There Is No Free Market for Electricity: Can There Ever Be?" *American Affairs Journal*.

64 A similar dynamic occurs with mandates such as an RPS: even in an otherwise "competitive" market, the RPS requirement obligates an off-taker, creating a private counterparty who can be sued. The RPS often then allows that counterparty to pass on costs (and, effectively, risk) to is own captive end customers, making the process similar to selective market re-regulation.

65 This is especially true if clean investment capital as a class is thought to face supply constraints because of other market failures. Even if clean energy capital deployment is in fact limited only by the level of risk-adjusted returns available to investors, then overlaps will still be undesirable from a social cost perspective.

Chapter 5: Policy Risk — Government Subsidies

Government subsidies have been pivotal in supporting a broad range of clean energy projects. When these subsidies are substantial, reliable and efficient they can make a real difference in the economics of a clean energy project. When they aren't they may have little impact, distort markets, waste resources, and harm public support for the incentives themselves.

This chapter considers subsidies of general applicability, i.e. available to any project of a particular type that is developed in a specified time period. Subsidies provided on a more project-specific basis to accelerate commercialization of innovative energy technologies are considered in chapter 6 (Innovative Technologies).

5.1 INVESTMENT RISK

Subsidies of general applicability come in a variety of forms in the energy project context and help projects by addressing high costs and/or low/unstable revenues through mechanisms such as:

- Reducing the upfront physical capital cost of a facility, for example, the U.S. IRC section 48 solar Investment Tax Credit and "viability gap funding" in India;"[66]
- Supplementing revenues with a per-unit tax credit or payment, for example, the \$23/MWh U.S. IRC section 45 wind Production Tax Credit or \$10/MT U.S. IRC section 45Q carbon sequestration tax credit;
- Providing a guarantee of payments to clean energy developers for the electricity they produce, for example, Feed-in-Tariffs in Europe and China, generation-based incentives in India, and Contracts-for-Differences in the U.K. and some Canadian provinces;
- Offering access to special debt or equity finance mechanisms that reduce the weighted average cost of capital for a project, such as U.S. tax-exempt private activity bonds for debt, or Master Limited Partnerships.

Subsidies can be problematic for investors for a variety of reasons:

- ***They may not be significant enough to make a real difference in the economics of a project***. For example, the U.S. federal tax credit for upgrading the efficiency of the "building envelope" of an existing home is capped at just $500 for all improvements.[67] Similarly, the existing IRC Section 45Q tax credit for CO_2 disposed of in secure geologic storage provides, as noted above, $10 per metric ton for CO_2 stored through EOR operations (and $20 per metric ton for CO_2 stored in deep saline formations) and is capped at 75 million metric tons of stored CO_2.[68] The $10 per metric ton is estimated at approximately one-quarter to one-fifth of what is likely needed to make the economics of a CCS project work.[69]
- ***Subsidies may be unreliable in various ways***. For instance, investors in U.S. CCS projects have found the 75 million MT limit noted above to be a serious impediment to CCS project investment because it is not all certain when the limit might be reached, at which point the subsidy would end. Further, the statutory and regulatory language for Section 45Q makes it uncertain what types of projects would qualify and therefore it can be difficult to predict when the 75 million MT limit might be reached.
- ***Subsidies may only be authorized for limited periods of time or even if available governments may be slow to pay them***. In the U.S. the wind production tax credit has stimulated substantial wind development. However, the credit's value to the industry as a whole has been diminished because the credit has faced a series of expirations since 2000 when the U.S. Congress first failed to reauthorize it. During one of these PTC expiration "cliffs," new U.S. wind development dropped from 13 GW in 2012 to 1 GW in 2013 and, following the renewal of the incentive, to 5 GW in 2014. This unreliable incentive has caused a dramatic boom and bust cycle in the U.S. wind industry, even as it has stimulated wind development.
- In China, the subsidies available through feed-in tariffs can take months or even years to be paid by the central government. A delay in payment to a project owner reduces equity returns because profits are deferred, but if the project is leveraged with debt, such a delay can cause a project debt default resulting in foreclosure and bankruptcy. There are also abrogation risks. For example, in 2010 the Spanish government made retroactive cuts in Feed-in-Tariff payments to renewable energy projects. Spain's Court of Arbitration found that project owners did not have a legitimate expectation that the regulatory framework established for renewable premiums in Spain would remain unchanged throughout the life of solar plants.[70]
- ***Subsidies may also be inefficient, i.e. too much of the subsidy ends up being eaten up in their implementation and not enough applied to the project itself***. U.S. renewable energy tax credits are a good example, with the "monetization" of the credits often relying on specialized "tax equity" investors who have sufficient "tax appetite" to use them, rather than the often thinly capitalized developers who frequently have little or no tax liability. The credit has clearly been a major stimulus for U.S. clean energy investment at both the utility and residential scale.[71] However, as the Bipartisan Policy Center found, "while the tax-based incentive system has been enormously supportive for the renewable energy industry, it is also a sub-optimal tool. . ...."[72] A 2015 Stanford paper summarized the inefficiencies of the renewable energy tax equity system: "The required tax equity is scarce and expensive, especially in a slow economy, limits investment liquidity, drives up transaction costs, precludes other, lower-cost financing options and, in the end, puts more money in the pockets of investors and lawyers than solar panels on the roof or wind turbines in the ground."[73] The paper found that in a tax equity regime "renewable energy developers can, at most, realize two-thirds of the value of their project's tax benefits."[74]

5.2 SOLUTIONS

The easiest fix conceptually but often the hardest in reality, is simply making subsidies more generous. In the U.S. context, there are regular efforts to increase the magnitude of subsidies, for example recently introduced bipartisan legislation that would triple the value of IRC Section 45Q tax credit for CO_2 sequestration.[74] China, on the other hand, is cutting its solar feed-in-tariff tariff as solar capital costs fall.[75]

The biggest challenge in increasing subsidies is the cost to taxpayers. In the U.S., proposed federal legislation is often generally "scored" by the Congressional Budget Office for its cost to the federal treasury, aka U.S. taxpayers, usually over ten years. These "scores" loom large in the likelihood a bill progresses legislatively, especially if "offsets" can't be identified elsewhere in federal government spending that would cut the cost of the bill. In an era of substantial federal government deficits and serious federal budget caps, legislating significant new subsidies is a particular challenge. The proposal to raise the subsidy level of the IRC section 45Q CCS tax credit, for example, will be scrutinized by members of Congress once OMB has scored the bill.

A second solution addresses the lack of reliability in subsidies. China has had a serious problem in paying its feed-in-tariff on time because of a shortfall in collections from its renewable energy surcharge and is considering "new models" to increase revenues.[76] In the U.S. there has been progress with respect to both solar ITC and the wind PTC which saw multi-year extensions, with scheduled phase-downs, in legislation adopted by the Congress and signed by President Obama in 2015. At the same time, the U.S. Congress did not renew a number of other clean energy tax credits — cogeneration, fuel cells, microturbines, geothermal heat pumps and small wind — that expired at the end of 2016. These so-called "orphan tax credits" would be extended through 2021 in a pending House Bill (HR 1090). There are also ongoing discussions about a potential further extension of the wind and solar tax credits.

Both the U.K. as well as some Canadian provinces have created a reliable equivalent of Feed-in-Tariffs that avoids some of the problems that have arisen in China and Spain. Through a mechanism, mentioned above in chapter 3, called a "contract for differences" (CFD) a government agency would pay the difference in cost between the contractual off-take price for a particular project and market price under a CFD that specifies the terms of the transaction. This tends to be a cost-effective approach because the government only pays when energy is actually produced and only the differential price. In cases where the market price rises above the CFD price, the government may actually be on the receiving end of payments. The key to this arrangement is that the project has a legally enforceable contract with the grid operator under which this CFD operates. The grid operator passes on the costs of the arrangement to all consumers via monthly power bills. Thus the CFDs are not subject to legislative budgets and do not require the sovereign to reimburse investors.

Another solution that is easy to sell conceptually but also may be challenging politically are improvements to the efficiency of a subsidy. The tax equity approach to monetizing the U.S. solar tax credit, as well as other tax incentives, is generally seen as inefficient, i.e. too much of the taxpayer dollar ends up in the hands of a small group of investors and their lawyers and too little in the energy project itself. There are a variety of pending approaches to improving the solar tax credit or replacing it. One of these was actually in operation earlier in the decade and saw widespread use. The American Recovery and Reinvestment Act (ARRA) gave renewable energy developers the choice between using the solar tax credit to offset existing liabilities or, under the so-called "section 1603 cash grant," turning these credits into "refundable" cash payments from the IRS. Developers voted with their feet and for the two years the cash grant was in effect it saw massive use.[78] As a 2015 Stanford paper concluded: "Making….tax credits for renewables refundable would lift the tax equity-imposed restrictions on the overall market size and growth of the renewable energy marketplace. With trillions of dollars of pension funds, sovereign wealth funds, and other currently sidelined investment capital finally able to participate in the build-out of clean, renewable energy technologies, growth in the solar marketplace would cease to be limited by the profitability and, hence, tax liabilities of some two dozen tax equity investors."[79] There are a variety of arguments in favor of refundable tax credits but there are only a handful of situations where Congress has put them in place, with Capitol Hill instead leaning strongly instead in favor of the current tax equity approach. "The opposition to refundable tax credits is based on concerns that refundability would turn the tax system into a welfare system and lead to fraud and abuse." [80] Additionally, a refundable tax credit typically requires an appropriation by Congress, whereas a tax credit does not. At the same time, these are clearly not insurmountable concerns as illustrated by existing refundable tax credits, such as the Earned Income Tax Credit and the Child Tax Credit.

There are also a variety of other alternatives to tax credits in the U.S. context. Two that have received great attention in recent years are Master Limited Partnerships (MLPs) and Real Estate Investment Trusts (REITs), that for decades have provided tax-advantaged financing for oil, gas and coal infrastructure (MLPs) and electricity transmission lines (REITs). Recent bipartisan legislation is pending in both the U.S. Senate and House to open up MLPs to invest in a broad range of clean energy technologies including renewables, energy efficiency, CCS, electricity storage, cogeneration and more.[81] [82] MLPs and REITs promote investment in eligible assets by paying income tax only at the investor level rather than both the entity and investor levels as classic corporations do. But like corporations, MLPs and REITs can be traded on public exchanges to increase investment liquidity and appeal to a broader range of investors than tax credits generally do. The 2015 Stanford paper summarized their advantages: "Importantly, unlike the highly limited access to investment provided by tax equity, publicly traded shares in renewable energy MLPs and REITs would allow millions of Americans to invest in the nation's energy future. And unlike YieldCos, an emerging vehicle for clean energy finance, MLPs and REITs do not require carefully balanced asset portfolios and federal tax credits to deliver critical tax advantages to renewable energy investors."

In May 2014, the IRS proposed new regulations to clarify the definition of real property for the purposes of REIT eligibility, with an eye in part toward renewable energy power generation assets.[83] The IRS finalized the rule in August 2016, but, in sum, extended REITs to renewables in a limited fashion.[84] These structures would be particularly logical to put in place as the solar and wind tax credits phase down. They would provide access to a financing mechanism that the traditional energy industry has long enjoyed.

ENDNOTES – CHAPTER 5

66 http://www.indianeconomy.net/splclassroom/272/what-is-viability-gap-funding-vgf/

67 https://energy.gov/savings/residential-energy-efficiency-tax-credit And this tax credit actually phased out at the end of 2016, having not been renewed by the U.S. Congress.

68 https://www.law.cornell.edu/uscode/text/26/45

69 $40-50/MT sounds high, but the reader is reminded this is a cost per ton of CO_2 abated and put in the ground. A wind PTC of $23/MWh, when the wind MWh avoids running a reasonably efficient gas combined cycle turbine, abates approximately 0.38 MT, which translates to a CO_2 abatement cost of ~$61/MT.

70 Forbes Magazine, "Spanish Court Rules Against Solar Challenges", January 31, 2016.

71 See Solar Energy Industries Ass'n, http://www.seia.org/policy/finance-tax/solarinvestment-tax-credit

72 See Bipartisan Policy Center, Reassessing Renewable Energy Subsidies — Issue Brief (BPC 2011) p. 13.

73 See http://law.stanford.edu/wp-content/uploads/2015/07/ITC-Report-to-DOE-FINAL-Jan-2015.pdf at

74 See http://law.stanford.edu/wp-content/uploads/2015/07/ITC-Report-to-DOE-FINAL-Jan-2015.pdf at

75 See https://www.heitkamp.senate.gov/public/_cache/files/7fe84fdc-f526-466d-aa83-4d3d392b0d3b/ccus-act-one-pager-115th-congress-.pdf

76 https://law.stanford.edu/publications/the-new-solar-system/ p. 151

77 Id at 153.

78 The 1603 program had both a hard deadline for start-of-construction originally set at December 31, 2010 and a placed-in-service deadline of October 1, 2011. If a project faced an unexpected holdup it could lose the critical underpinnings of its entire financial structure.

79 See http://law.stanford.edu/wp-content/uploads/2015/07/ITC-Report-to-DOE-FINAL-Jan-2015.pdf at 40.

80 Id at 41.

81 https://www.coons.senate.gov/newsroom/press-releases/sens-coons-moran-reps-poe-thompson-introduce-bipartisan-bicameral-legislation-to-level-the-playing-field-for-clean-energy See also https://www.govtrack.us/congress/bills/114/hr2883 See also http://law.stanford.edu/wp-content/uploads/2015/07/ITC-Report-to-DOE-FINAL-Jan-2015.pdf at 56.

82 Note that current tax law limits the ability of an individual investor in MLPs from using tax losses generated by MLP ownership to reduce taxes due on ordinary income from salary or stock and bond investment (see discussion of passive activity in chapter 9) https://www.oppenheimerfunds.com/advisors/article/what-is-a-master-limited-partnership/how-are-master-limited-partnerships-taxed

83 See Definition of Real Estate Investment Trust Real Property, 79 Fed. Reg. 27,508 (proposed May 14, 2014) (to be codified at 26 C.F.R. pt. 1). See also http://law.stanford.edu/wp-content/uploads/2015/07/ITC-Report-to-DOE-FINAL-Jan-2015.pdf at 54.

84 https://www.mwe.com/en/thought-leadership/publications/2016/09/final-regulations-define-real-property-for-reits

Chapter 6: Project Development Risk — Innovative Technologies

Innovative technologies are often too risky to attract development capital and long-term investment. At the same time, they can offer important improvements over current technologies in terms of efficiency, performance, cost, and emissions. Technologists, developers, and investors frequently struggle with how to finance energy projects deploying innovative technologies.

This chapter focuses on the risks in deploying innovative technologies in energy projects and a range of government support mechanisms to overcome them.[85]

6.1 INVESTMENT RISK

The challenge with an innovative technology in a clean energy project is that it may not work at all or it may not meet an expected performance level critical to financing and operating a project on a successful commercial basis. This prospect causes a significant conundrum. Investors often require significant performance data regarding an innovative technology before they will provide capital to build a first-of-a-kind (FOAK) commercial-scale project, and often the next few projects as well. But companies that have developed a new technology, often thinly capitalized start-ups, generally don't have the capital to build and operate a new technology at full scale and for a meaningful time frame to collect the data investors seek. Technologists, developers, and investors have labeled this challenging situation the "Valley of Death" where many technologies have perished.[86] On one side of the valley are venture capitalists who often fund the early stages, following initial government-supported R&D, of the development of a new innovative technology with relatively small amounts of high-risk capital. On the other side is the world of project finance that provides large amounts of relatively low-risk capital, generally a mix of equity and debt, for projects deploying well-established technologies. In the valley in between technologists and their development partners struggle to find enough capital — with a high-enough risk tolerance — to get a FOAK project and often a few follow-ons developed and built. Of course adding to the challenge is that many of these energy ventures produce a commodity product — kWh of electricity or gallons of fuel — and generally must compete with established traditional supplies and often in regulated markets. This is a fundamental distinction from many information technology and biotech ventures.

There are many examples of projects that struggled in the Valley of Death, both projects that died and others that got to the other side, some with often heroic help from investors or governments. In the CCS context, the Texas Clean Energy Project tried but eventually failed in developing an innovative CCS project even with the commitment of a $450M U.S. DOE grant and similar amounts of IRC Section 48A investment tax credits. The main issue that sank TCEP was constantly increasing prices for the project's Engineering Procurement and Construction (EPC) contract and decreasing quality of performance guarantees and warranties from technology providers and the EPC contractor.

In the solar context, the Brightsource Ivanpah CSP project in California had to call on its early-stage venture investors to make a significant — and not at all anticipated — project equity investment to get its flagship project built and operating, plus additional help from a $1.6B U.S. DOE loan guarantee. The project was completed but it had some start-up performance issues and the underlying technology has seen increasing competition from solar photovoltaics, particularly combined with storage. In the nuclear context, technologists and developers have struggled in recent years to get small modular reactor (SMR) technologies to a point where they are ready for various FOAK projects, often with significant DOE support. Some of the companies have left the SMR race after seeing the challenges of technology commercialization.

Some argue that the "system" is working — in a sort of survival of the fittest mode — when it leaves failed technologies behind in the valley of death. Sometimes this is the case. The Southern Company, for example, earlier this year halted a coal gasification project in Mississippi that was testing an innovative gasification technology and converted the associated power plant to natural gas, after spending $7 billion on the effort. The project has benefitted from both a $400M DOE grant and $133M of IRC section 48A Investment Tax Credits. Southern attempted to scale up the advanced gasification system from 6.9 MW to approximately 1000 MW thermal, arguably too big and fast a jump, with major associated cost overruns. This major jump was in part motivated by deadlines that if missed would have forfeited key federal assistance, including the 48A tax credits.[87]

At the same time, there is a long and, in many cases, successful history of early government support for innovative high-risk technologies. One major example is nuclear power. The federal government, in the Eisenhower administration, financed the commercialization of civilian nuclear power, fully funding ($550 million in current dollars) the Idaho EBR-1 reactor "where usable electricity was first generated from nuclear energy in 1951."[88] Further government-funded civilian reactors followed, including the federally-financed Shippingport reactor in Pennsylvania, "the world's first full-scale atomic electric power plant devoted exclusively to peacetime uses."[89] It was not until 1960 that "the first U.S. nuclear power plant [was] built without government funding."[90]The federal government has stayed in the nuclear power commercialization business helping to finance the scale-up of various technologies, some successful and some not. This includes federal funding of breeder reactors[91] and in recent years significant DOE investment in the development of SMRs. In the last few years, the DOE loan program backed the construction of the first new reactors in the U.S. in decades deploying the "next generation" of technology.[92] Recently, a bipartisan report to Energy Secretary Moniz concluded that the successful commercialization of U.S. advanced reactor technologies in at gigawatt-scale beginning in 2030 would require government investment, measured in the billions of dollars.[93]

Unlike other areas, for example information technology, energy technology tends to be capital and time-intensive, with decades and billions of dollars often required to take a technology from initial conception to full-scale commercial deployment.[94] For example, hydraulic fracturing ("fracking") technology saw its first experimental test in 1947 and Bell Labs created the first practical silicon solar cell in 1954. It would be more than five decades and many billions of dollars before each technology was making large-scale contributions to global energy systems.

6.2 SOLUTIONS

There are multiple solutions that can support the deployment of innovative technologies in clean energy projects. These solutions tend to chip away at risk at various points in the financing equation for a clean energy project. These include and are discussed below:

- Partial government grant funding of a project to cut overall project capital costs;
- A government loan or loan guarantee to cut borrowing costs lengthening repayment schedules;
- A buy-down of the generally above-market cost of energy produced at a project deploying a new technology (e.g. “contract for differences”);
- Tax-related incentives including tax credits, tax-exempt financing, and other tax-advantaged vehicles;
- Government procurement of a FOAK plant.

Government grants directly cut the amount of capital that must be raised to build a project and with it the effective cost of financing. For example, under the American Recovery and Reinvestment Act (ARRA) DOE made a variety of grants to innovative U.S. clean energy projects. For example, the Department issued a $167M DOE grant under the Clean Coal Power Initiative toward an innovative $1B CCS project developed by NRG Energy at one of NRG’s coal-fired units in Texas. DOE made an additional grant of $23M from FY2016 funds. The plant started up in January 2017 and has operated successfully since.

There are a variety of issues with grant support of innovative projects. One involves the timing and focus of funding. DOE typically shies away from funding early-stage development work on a project, preferring later grants after the high-risk, difficult-to-finance development work is done on permitting, contracting, interconnection and FEED studies. DOE’s caution certainly insulates the Department from failures but it does little to address some of the most potent risks in the development of an innovative clean energy project. The DOE could instead provide support for FEED studies and related contractor documents for innovative projects. This support would take direct aim at the serious problem developers have in securing bankable fixed-price turnkey contracts with EPC contractors and technology vendors for plants using innovative technology. When innovative energy projects are starved for funds in early stages, developers are at a serious disadvantage versus contractual counterparties who know well that scarce funds are dwindling, and the clock ticking.

Earlier stage grant funding would support not only new technologies like small modular reactors but also large assemblies of existing technologies where the large scale and complexity of the construction process are the major issues, e.g. post-combustion carbon capture. The UK government has in fact taken this approach. In its carbon capture project competition, the British Department of Environment and Climate Change offered to fund up to 90% of project costs.

In contrast with grants, which constitute one-time “money out the door” expenditures, loans are a federal financial mechanism that returns capital to the government, both principal and interest. A government loan can provide a real boost to an innovative clean energy project by ensuring access to low-cost long-duration debt, often the most challenging part of assembling the financing for a major energy-related project. The U.S. DOE loan program was funded in 2009 under the ARRA to provide loans and loan guarantees, pursuant to previously authorized (but not funded) programs, for innovative energy and transportation-related projects and also, for a brief period, “shovel-ready” projects to stimulate the U.S. economy.[95] The DOE Loan Program Office (LPO) received negative publicity as a result of a failed loan to the solar company Solyndra. However, most of the rest of the more than 30 investments to date have performed well, including a $465 million loan to U.S. auto manufacturer Tesla Motors at a critical moment in its efforts to buy a shuttered GM-Toyota manufacturing plant in California.[96] The loan was pivotal in Tesla's efforts to reopen the factory and was repaid nine years early, with interest.

Loan guarantees can unstick otherwise unavailable commercial loans or ones with a sky-high interest rate or unworkable repayment schedules, in a major technology category. For example, prior to 2010, there were no utility-scale PV projects in the United States greater than 100 megawatts. The DOE LPO helped finance the first five utility-scale PV projects, and since then the private debt markets have taken over, financing many more projects.[97] As of January 2017, there were 48 privately financed U.S. PV projects greater than 100 megawatts operating.[98]

A different solution focuses on the greater inherent risks and the resulting higher cost of capital that cause an innovative project to charge a higher price for the energy it produces. Through a mechanism called a "contract for differences" (CFD) (also discussed in chapter 5) a government agency supporting energy technology commercialization would pay the difference between the contractual off-take price and market price under a CFD that specifies the terms of the transaction. This tends to be a cost-effective approach because the government only pays when energy is actually produced and only the differential price. In cases where the market price rises above the CFD price, the government may actually be on the receiving end of payments. The UK has made significant use of the CFD including for "less established technologies" such as renewables, nuclear and CCS.[99] In 2015 the UK awarded CFD contracts to two offshore and 15 on-shore wind farms, two cogeneration projects and 5 solar projects.

On the tax front, there are multiple mechanisms to cut risk in an innovative energy project. Tax credits (also discussed in chapter 5 and chapter 9) figure prominently in helping to back projects deploying innovative energy technologies. For example, the IRC section 29 production tax credit for unconventional gas, was pivotal in the commercialization of hydraulic fracturing ("fracking"). The IRC section 45Q credit has been used to incentivize projects disposing of CO_2 in secure geologic storage through either enhanced oil recovery or in deep saline formations. And the IRC section 48 investment tax credit and section 45 production tax credit have been pivotal in stimulating investor interest and cutting the costs of solar and wind projects for developers and ratepayers.[100]

A different tax angle in the U.S. involves tax-advantaged investment vehicles, including Master Limited Partnerships (MLPs), Real Estate Investment Trusts (REITs), and tax-exempt Private Activity Bonds (PABs) (MLPs and REITs are discussed in chapter 5). A PAB is a bond issued by or on behalf of local or state government for the purpose of financing a project with a public benefit that is being pursued by a private entity. This type of a bond results in reduced financing cost for a project because of: 1) the exemption from federal tax; and 2) longer repayment terms versus typical bank debt. PABs have been used in the past to finance pollution control equipment at U.S. power plants. Pending bipartisan legislation would extend PAB authority to financing the deployment of CCS technology at power plants and industrial facilities.[101] Interestingly, NRG was able to use PAB financing at the Texas CCS project described above. The PAB financing authority was available because the plant was located in a hurricane zone where financing authorities that are not generally available are sometimes opened up to encourage rebuilding following a natural disaster.[102]

ENDNOTES – CHAPTER 6

85 There are also some substantial private sector efforts. For example, former Microsoft CEO Bill Gates and other investors have launched Breakthrough Energy Ventures to accelerate the deployment of new energy technologies. http://www.b-t.energy/ventures/ Additionally, there are a range of private entities focused on advancing energy technologies at earlier stages. See e.g. Cyclotron Road, http://www.cyclotronroad.org/home, and PRIME Coalition, http://primecoalition.org/what-is-prime/ .

86 There are more complex descriptions of the Valley of Death. See e.g. https://thebreakthrough.org/blog/Valleys_of_Death.pdf

87 See Burns and Roe expert testimony to Mississippi PUC at page 27, f.n. 48 as to 150x scale up of TRIG. Part of Mississippi Power's rush was to avoid forfeiting a $133 million 48A tax credit, as cited by Burns and Roe on page 6.

88 http://www4vip.inl.gov/ebr/

89 https://www.nrc.gov/about-nrc/emerg-preparedness/history.html

90 Id.

91 https://en.wikipedia.org/wiki/Clinch_River_Breeder_Reactor_Project

92 https://www.energy.gov/articles/vogtle-big-results-nuclear-power

93 https://www.energy.gov/sites/prod/files/2016/10/f33/9-22-16_SEAB%20Nuclear%20Power%20TF%20Report%20and%20transmittal.pdf

94 https://science.house.gov/sites/republicans.science.house.gov/files/documents/House%20Committe%20on%20Science%2C%20Space%20and%20Technology%20Loan%20Program%20Hearing%20REICHER%20Testimony%202.15.17%20Final%20.pdf p.3

95 https://energy.gov/lpo/loan-programs-office

96 https://science.house.gov/sites/republicans.science.house.gov/files/documents/House%20Committe%20on%20Science%2C%20Space%20and%20Technology%20Loan%20Program%20Hearing%20REICHER%20Testimony%202.15.17%20Final%20.pdf

97 https://science.house.gov/sites/republicans.science.house.gov/files/documents/House%20Committe%20on%20Science%2C%20Space%20and%20Technology%20Loan%20Program%20Hearing%20REICHER%20Testimony%202.15.17%20Final%20.pdf

98 Id.

99 https://www.gov.uk/government/collections/electricity-market-reform-contracts-for-difference

100 These are generally available tax credits. There are also a class of tax credits that require an application and are competitively awarded, e.g. IRC section 48A and 48B.

101 https://www.portman.senate.gov/public/index.cfm/2017/4/portman-bennet-introduce-bill-to-help-finance-carbon-capture-and-storage-projects

102 https://www.nytimes.com/2015/11/19/business/energy-environment/senators-revive-financing-tactic-from-70s-for-carbon-emissions.html?mcubz=3

Chapter 7: Project Development Risk — Government Approvals and Permitting

Governments have a great deal to say about clean energy projects, including what gets built, how, where and when. Government authority, at multiple levels, can make or break a project development deal or at least set the pace for its implementation. In a business where time is money this authority looms large in the risks around a clean energy project and related deal economics.

This chapter takes a brief look at three project investment risks and related solutions:

1. *Environmental permits;*
2. *Grid interconnection and transmission approvals;*
3. *Power purchase agreements.*

There are additional governmental approvals considered in other chapters including Electricity Market Design (chapter 2), Government Subsidies (chapter 5), and Rule of Law (chapter 8).

7.1 ENVIRONMENTAL PERMITS

The typical energy project must turn to federal, state and local governments for a range of environmental permits.

7.1.1 ENVIRONMENTAL PERMITS — RISK

Investment risks flow from multiple permit-related matters including siting, emissions, wetlands protection, land use, endangered species and a host of other issues. These permits involve both "procedural" requirements, e.g. prepare a federal or state environmental impact statement and "substantive" requirements, e.g. meet a specific EPA emission standard.

There are many permitting risks that can lead to timeline delays, litigation, and increased cost. These include: siting controversies (e.g. development adjacent to wetlands); emissions limitations (e.g. from natural gas or biomass power plants); endangered species (e.g. specific limitations on bird kills); and required mitigation efforts (e.g. for wetlands). While clean energy project may be able to avoid some of the permitting challenges that conventional energy infrastructure faces, it still shares many of the same requirements and additional uncertainty due to its relative novelty.

Two large-scale innovative U.S. clean energy projects are good examples of how permitting and a host other development issues can tie up projects. A wind developer worked for 15 years to develop a 130-turbine wind project in the waters off Cape Cod. The Cape Wind project was the object of substantial litigation largely brought by homeowners with views of the proposed turbine site, under a number of environmental laws including the National Environmental Policy Act (NEPA), the Endangered Species Act, and the National Historic Preservation Act. The project was also plagued by battles over grid interconnection and power purchase agreements. The developer halted the project in 2015 but both Massachusetts and the federal Bureau of Ocean Energy Management are moving forward to foster the development of other offshore wind projects. Cape Wind highlighted a number of the permitting challenges in developing this significant resource.

BrightSource Energy developed the Ivanpah CSP project in California, with major investment from NRG and Google. BrightSource prepared an exhaustive federal environmental impact statement and related analysis of many issues. One issue concerned endangered species and pursuant to a "biological opinion" from the U.S. Fish and Wildlife Service, BrightSource was required to physically relocate desert tortoises. As part of its environmental mitigation, BrightSource also agreed to cut the power output of the project, cut the size of the site, and move it away from the densest desert tortoise and rare plant habit. Environmental mitigation overall was an expensive and time-consuming process at Ivanpah but in the end, the project was permitted, and is on line today, and has only modest environmental impacts as it generates significant low-carbon electricity.

7.1.2 ENVIRONMENTAL PERMITS - SOLUTIONS

There are multiple current and potential solutions that can ease the investment risks that flow from government approvals, while still ensuring important environmental protection. One approach is focused on making upfront siting decisions or preparing broad environmental reviews that would establish a more reliable foundation for permitting specific energy projects that follow. For example, the Desert Renewable Energy Conservation Plan[103] helps identify areas suitable for construction of renewable energy projects across 22.5 million acres of federal, state and private lands in the Mojave and Colorado Deserts of Southern California. Similarly, under its Solar Energy Program[104], the Department of Interior has categorized its lands in six southwestern states that are excluded[105] from utility-scale solar energy development (about 79 million acres) and has identified "solar energy zones"[106] that are well suited for utility-scale production of solar energy and where the BLM proposes to prioritize development (about 285,000 acres).[107]

In a related vein, the Department of Interior established the "Smart from the Start" initiative to speed offshore wind development off the Atlantic Coast.[108] The initiative is designed to identify priority Wind Energy Areas for potential development, improve Interior's coordination with local, state, and federal partners, and accelerate the leasing process. Cape Wind, discussed above, would likely have benefitted from this approach. Another approach involves various ways to speed up permitting and increase federal agency coordination in federal permitting decisions. These include, for example, the Fixing America's Surface Transportation (FAST) Act and the Obama administration's executive order on infrastructure permitting.[109] [110]

7.2 INTERCONNECTION AGREEMENTS AND TRANSMISSION APPROVALS

Clean energy projects that generate electricity must interconnect with the existing grid and, in some cases, seek entirely new transmission capacity. Both grid interconnection and transmission development involve multiple government approvals at both the federal and state levels governing land use, wetlands, endangered species, water quality, historic and cultural resources etc. FERC oversees interconnection agreements for both large[111] and small generators.[112] In the case of transmission, FERC oversees transmission planning and cost allocation under FERC Order 1000.[113] However, the actual siting of a transmission line is typically under state authority although the federal government will often play a significant role where a line crosses federal land. The federal government is in the lead in projects involving the transmission system owned by the federal Power Marketing Administrations, for example the Bonneville Power Administration and the Western Area Power Administration.

7.2.1 INTERCONNECTION AGREEMENTS — RISK

There are a number of risks that developers and investors face in securing interconnection and transmission approvals. For example, often a "network upgrade" is required to accommodate the flow from a new generating plant, e.g. a wind farm. These upgrades come in different forms but, overall, an energy project will not be treated as complete, satisfying timelines imposed by power purchasers for delivery of electricity, until it is interconnected to the grid. Several problems are at play here including:

- Typically the timeframe for interconnection analysis and construction is longer than the timeframe for constructing a renewable energy project;
- The rules of a number of RTO/ISOs, following FERC Order 2003, require that the developer whose project interconnection creates the need for network upgrades should pay for construction upfront, subsequently being reimbursed by the ISO or RTO over a five-year period. There can be dozens of projects on the drawing board at once, often requiring massive "cluster studies" to assign cost shares which can change over time as projects come and go;
- In some projects, typical power purchase agreements contain default and termination provisions that can be triggered by the transmission provider's failure to perform its work in a timely fashion. However, the developer building the project is likely to have limited contractual remedies against the transmission provider because of FERC form contracts that limit damages assessed against the transmission system party;[114]
- There is often a conflict of interest risk, since a renewable power project may have contracts with two different arms of the same utility company. The first contract, a power purchase agreement (see below) with the "distribution division" of the utility faces a default if the project is delayed because of failure to complete interconnection to the transmission system. A conflict arises when that interconnection is governed by an interconnection agreement with the "transmission division" of the same utility.

7.2.2 TRANSMISSION APPROVALS — RISK

In the case of transmission development, the operative word is time. While a solar or wind project might take a few years to develop, finance and construct, a major new transmission line to service such a project can frequently take two or three times as long. The primary challenge in transmission is sitting, i.e. the objection of landowners to siting the project on their land, sometimes by eminent domain, as well as concern among nearby residents about living in the vicinity of a large power line. Unlike natural gas pipelines which are often buried and where FERC has primary jurisdiction over siting, in the case of electricity transmission lines, individual states typically hold much of the authority over this highly visible infrastructure (although federal agencies will need to sign off on a project where it crosses federal land). Moreover, where these projects cross through multiple states, there may also be significantly different equities, with states at the beginning and end of the transmission line seeing more of the related economic upside than states simply in its path. This is particularly true with high-voltage DC lines that are more efficient, but don't typically have intermediate interconnections.

The other challenge with transmission is cost allocation, i.e. who should pay for the development of a line and how. FERC Order 1000 requires regional transmission planning processes to develop a cost allocation method for new transmission based on a set of principles set out in the order to ensure that costs are "roughly commensurate" with benefits. There are a variety of approaches to cost allocation including, for example, the "Adjusted Production Costs" method and the "Avoided-Cost" method. There is much complexity in cost allocation under Order 1000 and, with it, substantial administrative controversy, sometimes litigation, and delay.

Despite the cost allocation issue, utility spending on transmission has more than doubled since 2010 and is projected to hit $22.5 billion this year, but "[t]hat spending, however, has largely not included large, multi-state projects, which are more difficult to get approved and built. The big systems that are going to allow for a much more dynamic bulk power market, within regions, and between regions — those are the tough ones."[115] [116] The challenge for many of these projects is that construction and operation of the underlying project — wind, solar etc. — often has to await the completion of the related transmission line which increases project development costs and puts key elements, like power purchase agreements at risk.

7.2.3 INTERCONNECTION AGREEMENTS AND TRANSMISSION APPROVALS — SOLUTIONS

Potential solutions in this context are broad-ranging. In the transmission context they include, for example: Congress granting FERC transmission siting authority like the agency has for natural gas pipelines; the Department of Energy making broader use of current authority it has in multiple states through its Power Marketing Administrations to site transmission lines, including eminent domain actions; implementing the 2015 federal FAST Act, discussed above, designed to accelerate and improve the cross-agency federal review and approval process for large infrastructure projects like transmission lines; strengthening the Energy-Right-of-Way Corridors Initiative under Section 368 of the Energy Policy Act of 2005; and simplifying cost allocation methodologies under FERC Order 1000.

There are also lessons to be learned from successes in specific states. Private, independent transmission developers in Texas, for example, sited more than 3000 miles of transmission lines between 2010 and 2014 at a cost of about $7B to link multiple new wind farms in west Texas to cities on the eastern side of the state. Admittedly, Texas, with its own isolated grid, meant that transmission developers did not face FERC planning or cost allocation requirements thus allowing for a simple "socialization of costs" methodology as well as straightforward siting process, including eminent domain authority. Nevertheless, the success in Texas shows that transmission does not need to be the extreme pinch point it has become for developing utility-scale renewable energy projects in the U.S.

On the interconnection front, there are a couple of possible solutions to the risks briefly described above. One idea would be to allocate the risk of failure to have a working interconnection to the power purchaser if the party constructing the interconnection facilities is an affiliate of the power purchaser. This is a state regulatory matter, since the purchasers are usually regulated distribution utilities, and the power purchase agreements usually require the approval of the state regulator. State regulators and the purchaser have far more ability to speed up or slow down an interconnection than a developer, especially since the interconnection is often built by the transmission subsidiary of the power purchaser itself. A second idea would be to move the financing obligation from the developer to the grid operator (ISO/RTO) since it has the power to assess transmission rates across the entire system, with virtually no financial uncertainty. The financing should take place on the credit of the strongest borrower in the system, not based on the uncertain prospects of a single often-fragile project.

7.3 POWER PURCHASE AGREEMENTS

Every power project faces a key issue for its project sponsor and its debt and equity capital sources: how can they be assured that there will be a revenue stream over many years to justify a large upfront capital investment? A power purchase agreement (PPA) is one of the several potential mechanisms for addressing this key issue. For many if not most power plants in the U.S., the PPA is one of the most critical contracts as it defines the revenue terms for a generating project and as such is key to obtaining non-recourse project financing.

There are a variety of types of power purchase agreements (PPA) but the key one for energy project investors involves a bilateral contract between a seller, e.g. an independent power company, and buyer, e.g. an investor-owned or publicly-owned utility, of the energy output of a plant (measured in MWh) plus a variety of other products including "capacity" (measured in MW), "ancillary services", and "environmental attributes" such as renewable energy and carbon credits.

The Federal Power Act gives the Federal Energy Regulatory Commission (FERC) authority to regulate the rates, terms, and conditions of *wholesale* sale of electricity in *interstate* commerce. *Intrastate* sale of electricity at wholesale is subject to state public utility commission oversight, except if the electricity is transmitted over an *interstate-connected* transmission network.

With many investor-owned utilities, many other types of utilities (e.g. municipal and cooperative utilities) and 50 state public utility commissions overseeing them, there are a large number of approaches to power purchase agreements. The California Public Utility Commission (CPUC), for example, "has broad authority under state law to oversee energy utilities' agreements with third parties to help ensure that state policy goals are met and that utility ratepayer interests are protected. This oversight includes approving agreements that energy utilities propose and, in other instances, directing the utilities to contract with third parties."[117] The CPUC has developed a detailed process for the review and approval of PPAs. In contrast, in "deregulated" states like Texas, there are no PPAs at all because generators sell into ERCOT's auction market that sets prices and dispatches generation.

7.3.1 POWER PURCHASE AGREEMENTS — RISK

There are a variety of risks that clean energy project developers and investors face related to PPAs. First, there are risks regarding whether the developer will succeed in entering into the PPA in the first place. A developer typically needs to expend considerable resources (time and capital) to be in a position to secure a PPA. For example, to have credibility with the utility, the developer may have had to secure a site, a grid interconnection (or at least be in a position to do so), and met many other project milestones, all of which can involve considerable costs. The PPA procurement process typically involves a formal competitive process (often called an RFO or Request for Offers) that is open to any qualified bidder. After a proposal is selected in the RFO process, the resulting PPA negotiations are often complicated, with multiple lawyers, financial analysts, and engineers at the table. They can often be time-consuming as well, sometimes dragging out the closing of a deal and with it missing deadlines for, e.g., key government grants and other subsidies

Second, there is the risk whether and when the executed PPA will, in fact, be approved by the applicable regulatory commission. Usually, this risk is not significant as utilities typically obtain commission approval of procurement needs and RFO processes before undertaking any procurement process. However, where there is disagreement within the state about what resources should be procured or where the project draws other controversy, the approval process for a PPA can offer another opportunity for opponents to attack a project. In the meantime, a developer is fronting large amounts of development capital with an expectation that the PPA, as negotiated, will be approved by the PUC.

Third, there is the risk whether the developer, having succeeded in entering into a PPA, will be able to finish the development, financing, construction, and commissioning of the project so as to start performing under the PPA. There are many examples of projects that failed at this stage for any number of reasons (e.g., environmental objections, failure of financing, failure or delays in grid interconnections). A developer is typically obligated to place a significant security deposit with the utility upon entering into the PPA and a developer will have many other significant costs, so a failure of a project at this stage is very costly.

Fourth, there is the risk that the developer, having succeeded in commissioning the project and commencing to perform under the PPA, will later encounter operational or regulatory/contractual issues challenges during the operating period. As examples, a wind project's operation may need to be curtailed from excess bird strikes, a biomass project may encounter fuel supply issues, a geothermal project may encounter issues with the sufficiency of the geothermal resource.

7.3.2 POWER PURCHASE AGREEMENTS — SOLUTIONS

The PPA risks described above are largely inherent in the difficult task of developing and financing long-lived infrastructure. Taking risks away from project developers (such as eliminating or reducing the deposit a developer must post when signing a PPA), would surely make projects easier for developers, but might ill serve the goals of a utility (and its ratepayers) who need some assurance that contracted projects will, in fact, be delivered.

Most utility procurement processes are vetted with commissions in advance and involve the use of form contacts. Nonetheless, the contracting process involves project-specific issues that need project-specific resolution. In some instances, commissions or state law could do more to limit challenges to PPA approvals that are consistent with prior commission procurement decisions.

Finally, many PPA challenges arise in the context of other project development issues. For example, the risk of signing a PPA and posting a substantial deposit is greater when other project uncertainties loom large. So PPA issues can often be addressed by alleviating such issues. For example, Southern California Edison decided to build the Tehachapi Renewable Transmission Project to an excellent wind and solar resource area in advance of specific wind and solar projects being procured.

ENDNOTES – CHAPTER 7

103 http://www.drecp.org/

104 http://blmsolar.anl.gov/program/

105 http://blmsolar.anl.gov/program/exclusion/

106 http://blmsolar.anl.gov/SEZ/

107 The program emphasizes and incentivizes development within SEZs and outlines a collaborative process for identifying additional ones. The program has also prepared a broad-scale federal environmental impact statement ("Programmatic EIS") for the approach, easing the complexity of project-specific EIS's that "tier" from it. This sort of approach would likely have helped the Ivanpah solar project, discussed above, with the significant EIS and other permitting challenges it faced.

108 https://www.doi.gov/news/pressreleases/Salazar-Launches-Smart-from-the-Start-Initiative-to-Speed-Offshore-Wind-Energy-Development-off-the-Atlantic-Coast

109 https://www.permits.performance.gov/about/recent-history-infrastructure-permitting-and-review-modernization-effort

110 The FAST Act, a 2015 bipartisan bill signed by President Obama, directs the creation of a new Federal Permitting Improvement Steering Council that will focus on speeding up permitting for transportation, energy, pipeline, broadband, and water projects that cost more than $200 million. By cutting project delivery time and reducing delays, FAST Act implementation could make private investors more comfortable with investing in U.S. projects. The new law also directs the launch of a pilot program that would authorize up to five states to use their own environmental review laws and regulations rather than those under the National Environmental Policy Act, and thereby potentially avoid duplicative requirements in the permitting process.

111 https://www.ferc.gov/industries/electric/indus-act/gi/stnd-gen/orders-gen.asp

112 https://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp

113 https://www.ferc.gov/industries/electric/indus-act/trans-plan.asp

114 See LGIA as Appendix 6 to Standard Large Generator Interconnection Procedures per Order 2003-C, p. 21 https://www.ferc.gov/industries/electric/indus-act/gi/stnd-gen/2003-C-LGIA.doc

115 http://fortune.com/2017/02/15/philip-anschutz-california-wind-power/

116 http://www.eei.org/issuesandpolicy/transmission/Documents/Trans_Project_lowres_bookmarked.pdf

117 https://www.auditor.ca.gov/reports/2016-104/appendix.html

Chapter 8: Investment Framework Risk — Rule of Law

The majority of the IEA's forecasted capital needed to meet the 450 Scenario will be spent in non-OECD countries.[118] Most of these countries haven't amassed large pension funds, insurance accounts, or mutual fund holdings. Large amounts of foreign capital will, therefore, be needed to fill this gap in the form of foreign direct investment, purchase of stock, or lending to companies and projects, all of which we call Foreign Investment (FI).

This chapter briefly considers how an unfriendly business climate and corruption, unfair treatment in obtaining entitlements, and broader rule of law issues can derail FI, particularly in non-OECD countries.

8.1 INVESTMENT RISK — OVERALL BUSINESS CLIMATE AND CORRUPTION

Investor risks are in part a function of the overall risks of doing business in certain countries. Investors have multiple concerns: a country's general system of taxation; investor rights; protection of foreign investors; enforcement of contracts, mortgages, and pledges of collateral; and bankruptcy laws. These general characteristics would pertain as much to a noodle factory as a power plant. The difference is that a power plant is more likely to require major capital investment, extensive permits, foreign equipment, and long-dated contracts.

The BRIC countries tend to have poor business climates combined with high corruption. Figure 14 shows three sets of rankings for the BRICs, plus the U.S., Singapore, and an amalgam of five EU countries for context: the World Bank's annual Doing Business[1319] survey; Transparency International's compilation of corruption rankings[120]; and The Economist's "Crony Capitalism Index."[121]

- The World Bank ranks 190 countries[122] on both business climate overall and specific categories that are crucial to foreign investors (1 = best).[123] In the World Bank rankings, #78 China was particularly poor on the protection of minority investors (#123) and paying taxes (#131). #130 India ranked among the worst on paying taxes and enforcing contracts (both at #172). #123 Brazil was poor on taxes (#149) and last of the four on foreign trade (#149). Russia did surprisingly well, hitting #40 for business climate overall.
- Transparency International's corruption rankings (1 = best) had a three-way tie at #79 among China, India, and Brazil while Russia ranked #131.
- Russia gained the dubious honor of ranking first (worst) in The Economist's Crony Capitalism Index.[124] This stands in stark contrast with Russia's relatively good World Bank rankings.

FIGURE: 14. Rankings of BRICs and Comparison on Business Climate and Corruption

Rankings of BRICs and Comparison on Business Climate and Corruption									
Country	2016 World Bank Business Climate Rankings (1 = best; 190 = worst)						2016 Transparency Int. Corruption Perception Index		Crony-Capitalism Index
	Business Climate Overall	Protecting Minority Investors	Paying Taxes	Trading Across Borders	Enforcing Contracts	Bankruptcy	Ranking (1 = best; 177 = worst)	Absolute Score (90 = best; 10 = worst)	Ranking 1-22 (1 = worst)
China	78	123	131	96	5	53	79	40	11
India	130	13	172	143	172	136	79	40	9
Russia	40	53	45	140	12	51	131	29	1
Brazil	123	32	181	149	37	67	79	40	15
EU Index	17	36	30	14	32	12	10	81	20
US	8	41	36	35	20	5	18	74	16
Singapore	2	1	8	41	2	29	7	84	4

8.2 INVESTMENT RISK — RULE OF LAW

By rule of law we mean the principle that all people and institutions are subject to and accountable to the law that is fairly applied and enforced. The more questionable the rule of law — whether in contractual matters, bankruptcy proceedings, tax systems and beyond — the greater the risk to FI. Higher risk drives up financing costs, thereby harming the potential for new projects. The few projects that do get built have to charge higher prices for their output, thereby driving up energy prices. Higher energy prices hurt customers and may undercut the popular support and political will needed for further decarbonization.

There are numerous examples of rule of law problems in both energy and non-energy contexts. Non-energy examples are germane because investors see issues like expropriation and contract abrogation in multiple countries, regardless of the particular industry. Some examples:

- Spain abrogated its Feed-in-Tariffs for solar, beginning in 2010, with Spanish courts finding that companies that had qualified for 25-year tariffs could not have a legitimate expectation that the regulatory framework established for renewable premiums in Spain would remain unchanged throughout the life of the solar plants. [125] [126]
- China forced wind turbine manufacturer Gamesa to train local supplier companies to meet a 70% local content requirement in violation of WTO rules. The newly-trained Chinese component suppliers then sold parts to new domestic Chinese wind turbine manufacturers, who subsequently "grabbed more than 85% of the wind turbine market, aided by low-interest loans and cheap loans from the government, as well as preferential contracts from the state-owned power companies that are the main buyers of the wind turbine equipment."[127]
- In 2016 China promised to replace a discretionary "approvals-based" system for foreign investment with a simpler "registration based" system, but China's onerous requirements for transfer of intellectual property and constraints on repatriation of profits are nonetheless expected to remain a significant barrier to investment.[128]
- In India, the Dabhol power project started production in 1999 but the owners (Enron, GE, and

Bechtel) closed the $1.1 billion plant in 2001 and scrapped the 80%-built second phase after the Maharashtra State Electricity Board (MSEB) had fallen $240 million behind on power payments. As the Economist noted, "As in other [Indian] states, Maharashtra's politicians oblige the electricity board to supply power at below cost to farmers and other favored consumers. Moreover, MSEB loses a third of the electricity it buys to theft and leakage. The combined annual losses of India's state electricity boards are staggering." [129] The MSEB alleged that corruption led to the shutdown of the plant, but the real reason appeared to be that the new power was expensive, especially in light of MSEB's poor financial condition.

- In Russia in the mid-2000s, Yukos Oil, 15% owned by foreign investors, went bankrupt as the government claimed it owed $27 billion in back taxes. The government froze Yukos bank accounts, seized its largest subsidiary, and then demanded immediate payment from bank accounts the company could no longer access. The Permanent Court of Arbitration in The Hague "concluded that the government's action was an 'unlawful expropriation' using 'illegitimate' tax bills, whose effect was intended to 'destroy Yukos and gain control over its assets" and awarded investors $100 billion.[130] The judgment was overturned on appeal because Russia had signed a treaty protecting investors but had not ratified it.[131] On the fifth anniversary of the event, the Moscow Times said: "[T]he fallout from the Yukos affair cannot be measured in financial terms alone. The longer-term and far more detrimental effect is that there is now an assumption of political interference, corruption, and arbitrary use of state powers in civil disputes."[132]

8.3 INVESTMENT RISK — ENTITLEMENTS FOR ENERGY PROJECTS

Another set of risks, with a strong rule of law connection, relates specifically to the predictability and fairness of obtaining the "entitlements" that undergird clean projects. By "entitlements" we mean the panoply of government rights and incentives upon which a specific project relies to attract investors and then stay in business. This includes the risks that these entitlements will later be rescinded or otherwise threatened. Awarding these entitlements often involves significant administrative discretion by government officials of host countries. Entitlements include:

- Subsidies, as described above in Chapter 5, such as Feed-in-Tariffs, Contracts for Differences, etc.;
- Power purchase agreements (PPAs), as described in Chapter 7, that require regulatory approval or procurement decisions by national electric utilities;
- Rights to critical inputs such as water, natural gas, etc. without arbitrary interruption;
- Rights to emit certain amounts of pollution under applicable laws and regulations;
- Transmission access on a non-discriminatory basis at rates of general applicability;
- Rights to operate a plant once it has been constructed in accordance with specifications originally agreed with the government.

A persistent pattern of siding with local firms and against foreigners in entitlements can seriously affect FI. For example, the NY Times reported in 2009: "When the Chinese government took bids this spring for 25 large contracts to supply wind turbines, every contract was won by one of seven domestic companies. All six multinationals that submitted bids were disqualified on various technical grounds like not providing sufficiently detailed data." [133] Actions like this can have a chilling effect on foreign firms considering clean energy investments in China.

8.4 SOLUTIONS

It is clear that governments in non-OECD countries will need trillions of dollars of FI to meet carbon reduction goals, such as the Nationally Determined Commitments made in the Paris Agreement.

This FI will not be made in many of these countries without major structural reform including addressing the business climate and corruption issues above. According to the OECD, "Through structural reforms, governments need to create a more favorable investment climate, build private sector confidence to invest and ensure that global savings are channeled into productive investments." [134]

In addressing rule of law problems, there is a tension between "perquisites" and "prerequisites." All governments, from superpowers to recently independent former colonies, jealously guard the *perquisites* of sovereignty, i.e. the ability of a newly elected government to repudiate agreements and budgetary priorities set by the prior administration. Governments also press to litigate disputes with foreigners in host country courts using host country law. Meanwhile, the *prerequisites* of successful energy project financing require that government agreements for various entitlements survive changes of administration and that agreements can be efficiently enforced by impartial courts, even if unpopular with governments, powerful economic interests, or the broader populace.

It is possible to create long-term government-sanctioned subsidy and support mechanisms that are protected from a changing of the political guard. An example is an approach taken by the U.K. and some Canadian provinces to contract-for-differences (CFDs), discussed in chapter 6, that both stabilize and subsidize the revenues of clean power projects that sell to deregulated grids. These CFDs have utilized non-sovereign entities to be the contractual counterparties to the clean power projects. A government directs the grid operator to sign the contracts and authorizes the grid operator to spread contract-related costs over the ratepayer base. Thus, there is a non-government source of funds, and there is a non-sovereign contractual counterparty that the clean power project can sue if necessary.

It might also be possible to use multi-lateral treaties to move government vs. clean power project disputes into internationally recognized tribunals. International climate-related treaties or agreements, such as the Paris Accord, might require that contract disputes between clean energy developers and sovereigns (including state-owned enterprises) be subject to international arbitration. Signatories would agree to waive sovereign immunity when contracting with foreign-owned clean power projects and to submit cases to binding international arbitration as a first step. That would reduce the likelihood of investors whose property is expropriated being left without remedies as in the Yukos case.

A barrier to such a treaty-mandated international arbitration approach is that contractual or expropriation disputes are sometimes intertwined with countries' internal matters such as wages, safety, or environmental protection. For example, when Germany phased out nuclear power after the Fukushima disaster, the Swedish firm Vattenfall lost money on its German nuclear plants. Vattenfall contended it was damaged by expropriation, while Germany countered that the accelerated nuclear phase-out was a change in environmental law and a normal business risk to all investors.[135] A German court ultimately sided with Vattenfall[136] as to its property claims, and meanwhile, Vattenfall is also pursuing a related action in the International Center for Settlement of Investment Disputes in Washington, D.C.[137]

ENDNOTES – CHAPTER 8

118 World Energy Investment Outlook 2014, p. 42, Table 1.6. 55% of non-fossil power spending and energy efficiency spending takes place in non-OECD countries.

119 See http://www.doingbusiness.org/rankings "Top EU" was an average of Germany, Netherlands, France, UK, and Denmark.

120 "Corruption Perception Index" of Transparency International, 2016 "Full Data Set with Regional Tables" excel file downloaded 9/6/2016. https://www.transparency.org/news/feature/corruption_perceptions_index_2016

121 "Our crony-capitalism index — The Party Winds Down", The Economist, May 7, 2016.

122 http://www.doingbusiness.org/rankings

123 The Economist magazine has roundly criticized the World Bank rankings. See e.g. "Pulling Rank: the Shortcomings of the World Bank's Business-Climate Index" of September 24, 2015. https://www.economist.com/news/finance-and-economics/21667925-shortcomings-world-banks-business-climate-index-pulling-rank

124 "The Party Winds Down", The Economist, May 7, 2016. India ranked #9, China #11, Brazil #15, U.S. #16.

125 Spanish Court Rules Against Solar Challenges," Forbes, January 31, 2016.

126 PV Magazine, "Spain Loses Its First Renewable Energy Case in International Courts" by Blanca Diaz Lopez, May 5, 2017.

127 "To Conquer Wind Power, China Writes the Rules", NY Times, December 14, 2010.

128 "Mixed Messages — A Missed Opportunity to Improve the Environment for Foreign Companies in China", The Economist, October 1, 2016.

129 "Generation Gaps" (January 11, 2001) and "Can Dabhol Be Fired Up Again?" (April 29, 2004), The Economist.

130 https://en.wikipedia.org/wiki/Yukos Accessed online 9/11/2017.

131 "Dutch Court Overturns $50 Billion Ruling Against Russia in Yukos Case" NY Times, April 20, 2016.

132 https://themoscowtimes.com/articles/yukos-bankruptcy-5-years-on-8597 Accessed online 9/11/2017.

133 "China Builds High Wall to Guard Energy Industry", NY Times, July 13, 2009.

134 "Institutional Investors and Long-Term Investment — Project Report May 2014", OECD, page 3.

135 "Playing Nicely: Europe Suggests Ways to Protect Governments from Investors", The Economist, May 9, 2015.

136 http://kluwerarbitrationblog.com/2016/12/29/german-constitutional-court-judgment-vattenfall-case-lessons-ect-vattenfall-arbitral-tribunal/

137 http://news.vattenfall.com/en/article/vattenfall-case-against-germany-starts-ICSID

Chapter 9:
Investment Framework Risk — Tax Issues

Tax subsidies are often a life-or-death matter for energy projects, so certainty regarding these incentives is a matter of keen interest to developers.[138] A developer needs investors who can monetize these benefits and count on their availability upfront and over time. Factors that compromise these requirements increase financing costs and discourage new projects.

This chapter focuses on tax incentives in the U.S., where there is heavy use of federal tax law to promote clean energy. Chapter 5 (Subsidies) analyzes investment risks in a broader range of clean energy support mechanisms.

9.1 INVESTMENT RISKS

Even as Congress enacts specific tax incentives to aid clean energy investment, these incentives are undercut by three fundamental issues:

- Tax incentives can only change the behavior of parties who pay tax;
- Various tax provisions discourage remaining investors who *do* pay tax;
- The incentives themselves may have disparate impacts on similar investors and also contain arbitrary deadlines, "recapture provisions" etc. that discourage potential investors.

There is an important factor in understanding various tax risks, i.e. most clean energy projects are structured as "pass-through entities" for tax purposes, typically Limited Liability Companies (LLCs). LLCs avoid "double taxation" at both the project and corporate level and create a convenient means of pledging partnership shares and assets to banks, shielding owners of power plants from operating liabilities, and moving debt "off balance sheet" for corporate owners.[139]

Corporate Taxpayers versus Pass-Through Entities

In the U.S. projects can be taxed as "corporations" (Subchapter "C") or, alternatively, as pass-through entities (Subchapter "K") in the case of partnerships, Limited Liability Companies (LLCs), and Master Limited Partnerships (MLPs). A corporation is itself a taxpayer, files its own tax returns, sends payment to the IRS, and then distributes dividends with remaining after-tax profits to shareholders who — if they are taxpayers — also pay taxes on the dividends received (hence "double taxation"). On the other hand, a pass-through entity does not pay tax; instead, it sends its partners (with a copy to the IRS) a "K-1" partnership return that assigns gains and losses pro rata to the partners' ownership percentage. Each partner then pays tax, i.e. "single taxation."

FIGURE: 15. Examples of U.S. Clean Energy Tax Incentives

Examples of U.S. Clean Energy Tax Incentives			
	Depreciation	Investment Tax Credit	Production-type Tax Credit
Wind[140]	5 yr Class Life & 5 yr MACRS	N.A.	$24/MWh PTC per IRC §45
Solar PV	5 yr Class Life, with 5 yr MACRS; 50% ITC deducted from basis	30% of all qualified capital cost per IRC §48(a)	N.A.
CCS	5 yr Class Life, with 5 yr MACRS (if standalone)[141]; 100% of ITC deducted from basis	30% of qualified capital cost up to amount approved by DOE per IRC §48A, §45B	Sequestration credit of $10/MT for CO_2 for EOR; $20/MT for saline injection; 75MM MT program cap

In Figure 15 above we categorize several clean energy tax incentives by industry and by incentive type. Note that the accelerated depreciation *tax deduction* is a weaker incentive than a tax credit for two reasons. A $1 tax credit can be used dollar-for-dollar to reduce *tax payments* to the IRS. One dollar of depreciaion expense offsets *taxable income* dollar-for-dollar that, since U.S. corporate tax rates are 35%, reduces tax payments by 35¢. Further, this 35¢ is not a permanent benefit. The 35¢ of extra depreciation expense "accelerated" into the current year is eventually counteracted by 35¢ less depreciation expense in future years.

9.1.1 LIMITED UNIVERSE OF TAXPAYERS AND UNCERTAIN "TAX APPETITE"

The ability of investors to use tax incentives reliably and efficiently depends on whether, when, and at what rate an investor is likely to pay U.S. income taxes. Fundamentally, a clean energy project only has two means of attracting equity investors: cash payments and tax benefits. Considered in isolation, an individual clean energy project will typically have such large tax deductions for interest and depreciation that it is unlikely to be a taxpayer in the first place and thus has little use for extra deductions or tax credits. Further, a clean energy project that has excess credits cannot normally turn them into cash or sell them.[142] So, the only means of using these incentives is for a large taxpaying entity to acquire a stake in such project and then combine losses and credits from the clean energy business to create a tax shelter for its operations. If an investor can utilize clean energy tax incentives to reduce its tax bill, it has "tax appetite."

Who might have tax appetite? A profitable investor-owned utility might have both a strategic interest in owning a wind farm and also have a tax appetite, thus being an ideal investor. A major financial institution may have no stomach for the risks of owning an energy project, yet be attracted to the related tax benefits that would come with such ownership. Such investors can invest in an energy project to secure the tax benefits and are known as "tax equity investors."

As shown in Figure 16 below, the universe of parties with "tax appetite" is significantly reduced because some investors don't pay taxes at all, e.g., charitable foundations or public pension funds. Further, some corporate investors are in volatile, cyclical industries, paying substantial taxes in good years and no taxes in bad years, with little ability to forecast their own tax appetite. These factors shrink the universe of potential tax-motivated investors. The smaller that universe,

FIGURE: 16. Who Pays Taxes and Who Doesn't?

Who Pays Taxes and Who Doesn't?	
Taxpayer Investors	Non- Taxpayer Investors
Corporations generally (18% of federal income taxes paid) Individuals generally (82% of federal income taxes paid)[144]	Corporations that have large accumulated tax losses[145] or are not earning federally taxable income Professional real estate investors[146] Partnerships, LLCs, MLPs – *the investors pay tax, not the entity* Pension funds, charitable trust, endowments[147] Individuals re investments in IRA's 401(k)s etc. Foreign governments re investments in stocks and bonds[148] State government "permanent funds" (e.g., AK, WY) Municipal and cooperative utilities

the less certain that developers can successfully find investors and if they do the more the developers will likely have to pay them.[143]

9.1.2 THE TAX CODE FURTHER RESTRICTS INVESTOR BASE, RAISING FINANCING RISK

The modest universe of actual taxpayers shrinks further because of passive activity rules for individuals, the corporate Alternative Minimum Tax (AMT), and various special rules, for example relating to Sovereign Wealth Funds.

- ***Passive activity rules:*** The IRC knocks out virtually all individuals (who pay 82% of all taxes) by categorizing an individual's ownership of an LLC interest as a "passive activity." Unless a partner/member is highly involved in running the LLC, taxable income, expenses, and credits shown on the partner/member's K-1 are all treated as relating to a "passive activity" and lumped with his other LLC activities into a segregated "passive activities basket." Tax credits and deductions in that basket cannot be used to reduce taxes on salary, interest, dividends, or portfolio capital gains. In other words, Bill Gates can't use tax credits from a wind farm partnership to offset his taxes on Microsoft dividends.
- ***Corporate Alternative Minimum Tax:*** This tax code provision eliminates a broad swath of corporations from the "tax appetite" ranks. In simple terms, Congress enacted tax code provisions to ensure that corporations couldn't entirely escape paying taxes using all the various incentives provided by the tax code. Under the Alternative Minimum Tax (AMT), corporations calculate a second tax bill by reversing most incentive deductions and credits, but using a lower percentage tax rate (20% instead of 35%). The practical effect of clean energy investors subject to AMT is to (1) reduce the value of incentive deductions (e.g. accelerated depreciation) and (2) limit the rate at which tax credits can be used.[149] Thus the actual universe of potential corporate investors is limited to those who are confident they *will* pay tax in general and they *will not* be subject to AMT.[150]

- ***Sovereign Wealth Funds and "commercial activity"***: The tax code also discourages sovereign wealth funds (SWFs), major holders of total global capital, from investing in U.S. clean energy projects. In simple terms, pursuant to bilateral tax treaties national governments don't normally tax other governments' investments — either within a host country or when the foreign investor repatriates earnings. IRC Section 892, implementing these bilateral treaties, allows stock and bond investments of SWFs in the U.S. market to escape taxation entirely. However, earnings generated by SWF partnership stakes in U.S. "commercial activities" (including clean energy projects) are subject to withholding taxes when SWFs seek to repatriate earnings.[151] Thus, despite the fact that many SWFs have strong interest in clean energy projects, they often invest instead in NYSE-listed stocks and avoid investing in U.S. clean energy LLCs

As a consequence of these and other restrictions, the small group of investors both qualifying for and interested in tax equity investing can afford to be very choosy, leaving developers unsure up until the day that financing is completed whether they can find an investor with tax appetite. This has a variety of consequences: it raises the cost of financing early-stage project development; makes it difficult for developers to decide how to price their output; leaves developers struggling to determine how much debt they can incur; and reduces developers' negotiating leverage vis a vis tax equity investors. On this final point, a recent Stanford paper concluded, "[S]uch tax equity investors are few and far between — and they exploit their exclusivity status to charge a premium for their involvement."[152]

9.1.3 PROBLEMS WITH SPECIFIC TAX INCENTIVES

In the discussion above we highlight ways the general tax system makes it difficult to use specific incentives. Here we discuss provisions contained within particular incentives that introduce uncertainty and thus undercut efficacy.

9.1.3.1 DISSIMILAR TAX TREATMENT OF SIMILAR PROJECTS COMPOUNDS UNCERTAINTIES

Sometimes the tax code simply treats similarly situated, low-carbon projects in perplexingly different ways, raising investor risks. Two examples:

- Some grants are taxed and others are not. Government grants to *corporations* are not taxable pursuant to IRC §118, a provision dating from 1954, a time when the large-scale use of pass-through entities was not envisioned. Congress has not amended §118 to apply to *pass-through entities, i.e., LLCs*. Thus CCS projects owned by LLCs with federal grants under the Clean Coal Power Initiative were surprised to learn they had to pay taxes on their grants. In contrast, renewable energy LLCs receiving grants "in lieu of tax credits" under Section 1603 of the 2009 American Reinvestment and Recovery Act (ARRA) were not taxed because of a special exemption in the ARRA.
- It is simpler to use solar tax benefits than wind tax benefits. The tax-owner of a solar farm can utilize a 30% ITC, even if it leases the project to another entity. This facilitates conventional leasing transactions between an investor with tax appetite and a solar developer. For a wind farm, in contrast, the PTC can only be claimed by an entity that is both the tax-owner and the wind farm operator.

This rules out simple leases and has spawned complex “tax equity” partnership transactions with colorful names like “tax equity flips.” As a result, tax-motivated investors and cash-motivated investors are forced to cohabit in a single LLC, attempting to steer tax benefits disproportionately to the tax equity investors without violating IRS partnership allocation rules. This has driven up the cost of equity capital for wind farms, compared with solar projects.[153]

9.1.3.2 MISSING DEADLINES, RECAPTURE, AND LINKS TO UNCERTAIN ENVIRONMENTAL LAWS

Congress sometimes offers attractive programs to incentive clean energy but they are only available for a limited time. In the complex world of project development, this can be problematic because uncontrollable timing problems with construction or a regulatory approval could cause a project to miss the deadline and lose access to the incentive. The wind and solar industry have had incentive-related “boom and bust” cycles with expiring and reinstated tax credits. The “bust” portion of the cycle starts prematurely because developers face unknown timing risks and with them the potential of losing the ITC or PTC.[154] Similarly, once carbon capture projects were awarded ITCs under the IRC Section 48A program, the projects had only 5 years to go into service or the ITC benefits could not be claimed. Most projects awarded these credits had to let them lapse. One project was constructed with undue haste to meet the 5-year deadline only to experience the worst of all worlds: it had to repay the ITC to the IRS and also incurred massive cost overruns because of the rush.[155]

Another risk is the potential for a debt default to trigger a recapture — or “clawback” — of ITCs the investor has already claimed. Recapture provisions were designed to prevent owners from claiming the ITC and then immediately selling the project. They provide that if ownership of an LLC changes hands within five years of receipt of the ITC, the ITC is clawed back by the IRS — and this includes circumstances in which the ownership change is triggered by a debt default leading to the seizure of the project by lenders. Therefore, if a clean energy project company both borrowed money and executed a tax equity transaction, a default on the debt during the first five years of operation would trigger a recapture of ITC. Therefore, tax equity investors typically prohibit project companies from borrowing, which drives up financing costs to the project.[156] [157]

Other investor risks are created by links between tax benefits and certain environmental laws. These links can be problematic if receipt of a tax credit is tied to complicated or controversial environmental regulation. An example is a still-unresolved nexus between §45Q carbon dioxide sequestration tax credits and EPA greenhouse gas accounting rules. Amendments to §45Q in the ARRA[158] required the IRS to establish tax regulations in “consultation with” EPA to ensure that CO_2 used in oilfields for which the credit was claimed did not “escape into the atmosphere.” Effectively, Congress was asking the IRS to write environmental regulations under the aegis of tax regulations. The IRS offered interim guidance in 2009 but never finalized regulations as required by statute.[159] EPA stepped into the breach but developed an approach that many operators of the relevant oilfield operators see as onerous.[160] To date, in part because of the lack of a formal IRS rulemaking, only one CCS projects has been built to claim the §45Q credits.[161] Instead, the credits have been used by existing CCS facilities selling to existing CO_2 enhanced oil recovery operations and in effect being rewarded for what they already were doing.

9.2 SOLUTIONS

A number of relatively straightforward solutions could make U.S. tax incentives more effective by reducing risks:

- Expand the investor base by carving out clean energy LLC ownership from passive activity rules;
- Allow use of clean energy tax credits to offset 100% of “Tentative Minimum Tax” under the Corporate AMT;
- Exempt from withholding taxes the repatriation of dividends earned by SWFs in clean energy LLCs;
- Update IRC section 118 to exempt LLCs as well as corporations from taxation for grants received;
- Improve tax credits based on performance (e.g. wind PTCs or 45Q sequestration credits) by conditioning the credit only on tax ownership of the asset (rather than on both ownership and operation) thereby facilitating simple lease transactions;
- Set deadlines for use of tax credits that reflect real-world considerations of project development timelines (e.g. lengthen five-year deadline for IRC Section 48A CCS credits);
- Exempt involuntary change in ownership caused by loan foreclosures from ITC claw-back; and
- Clear up regulatory ambiguity in situations where tax benefits are linked to compliance with an environmental or other law.

ENDNOTES – CHAPTER 9

138 For example, the returns to equity owners of a project may be 4% without tax benefits (a poor return), but 15% with full utilization of tax benefits (an acceptable return). It is not enough simply to have attractive depreciation provisions or tax credits currently on the books.

139 Consolidation of debt for accounting and credit purposes is arcane, and the "off balance sheet" statement above is a simplification. There was formerly a 51% test for debt consolidation, replaced by "V.I.E." rules.

140 $24/MWh is $15/MWh x 1.5792 for inflation since 2002. For projects that began construction by Dec. 31, 2016, the same $24/MWh production tax credit regime and 5 year accelerated depreciation shown here for "wind" also covered geothermal and closed-loop biomass, with a smaller $12/MWh covering some other technologies including tidal, certain hydro, open loop biomass, and municipal solid waste. While the wind credit was reauthorized in 2015 these other credits were not.

141 For CCS, if operating and commissioned as a standalone facility, CO_2 production is treated as chemical production, whereas if integrated into and commissioned with a power plant likely 28yr/20yr MACRS (if integrated w/ coal) or 20yr/15yr MACRS (if integrated w/ gas turbine). See IRS Pub 946 (2016) Table B-2 "Class Lives and Recovery Periods."

142 There have been rare instances of "refundable tax credits" or special periods when Congress allowed tax credits to be exchanged for cash (see discussion of §1603 grants in Government Subsidies chapter).

143 See Comello, Reichelstein, Mormann, Reicher et al, "The Federal Tax Credit for Solar Energy: Assessing and Addressing the Impact of the 2017 Step-Down", January 2, 2015, pp 23-29. http://law.stanford.edu/wp-content/uploads/2015/07/ITC-Report-to-DOE-FINAL-Jan-2015.pdf

144 http://www.taxpolicycenter.org/statistics/amount-revenue-source

145 U.S. companies pay taxes based on their income computed for federal tax purposes, not based on pre-tax net income under Generally Accepted Accounting Principles or GAAP. A company can be doing quite well in terms of GAAP net income and cash flow and yet have accumulated excess tax losses and unused tax credits that shield the company from paying taxes almost indefinitely. Even though a company has 20 years from creation of the particular loss or credit period to use it up, many major investors in renewables and low-carbon energy have such large accumulated losses/credits that their accountants push them to write off portions of the losses/credits for GAAP purposes because they are likely to expire unused. See NRG 2017 10-k, p. 206, showing ("valuation allowance") that it is unlikely to be able to use $4.1 billion out of its $4.7 billion of "deferred tax assets." https://www.sec.gov/Archives/edgar/data/1013871/000101387117000007/nrg201610-k.htm

146 A complex topic, but suffice it to say, both because of how "passive activities" are defined and how the "at-risk rules" are written, it is easy for a real estate mogul to pay zero taxes even though a clean energy partnership and a real estate partnership are both likely to be "passive activities" for most investors. This is because a the IRS describes a professional real estate investor as someone who spends more than half his working hours on all real estate activities — as opposed to normal passive loss rules that apply partnership-by-partnership — and because "at risk rules" do not apply to real estate professionals. https://www.thetaxadviser.com/issues/2014/jul/skarbnik-july2014.html

147 Though pension funds, charitable trusts, and college endowments aren't taxpayers per se, the IRS ensures that income from any business activity in the U.S. is taxed at least once, if not twice. Thus, if a pension fund gets a dividend from Exxon, Exxon has already paid corporate income tax, which is acceptable to the IRS. If the pension fund directly ran a business, the profits would escape taxation. Thus, the IRC categorizes profits from a business run by a pension fund as Unrelated Business Taxable Income (UBTI or UBIT) which is taxed at 40%, and which if too large may result in loss of tax-exempt status. To avoid the UBTI problem, pension funds participate in LLCs only indirectly, via pension fund ownership of a specially formed "blocker corporation" that is the LLC partner. The blocker pays corporate income tax based on K-1s received from the LLC and remits dividends (that are not further taxed) to the pension fund. http://www.hurwitassociates.com/taxation-of-unrelated-business-income/taxation-of-unrelated-business-income

148 SWFs that own interests in LLCs also must do so through "blockers" as described in the prior footnote, but in addition they are subject to withholding taxes of 30% when they repatriate dividends to their home countries as described in the next subsection.

149 Curtis Carlson and Gilbert Metcalf, "Energy Tax Incentives and the Alternative Minimum Tax", National Tax Journal, Vol. LXI, No.3, September 2008, p. 477-491. The limit on usability of energy tax credits is NOT based upon the size of regular tax liability alone, but rather must include reference to the Tentative Minimum Tax (TMT). Consider a company that has a non-refundable tax credit available of $125, computes regular taxes owed (before application of credits) of $100, and computes TMT (before application of credits) of $50. Disregarding AMT, one would think that $100 of the $125 credit could be used, bringing the actual cash tax payment to zero. Actually, only $50 of the credit can be used, brining actual cash tax payments down to $50 (the TMT liability). (Example adapted from text in Carlson and Metcalf, p. 480.)

150 Typical pure tax equity investors would include financial institutions such as JP Morgan, US Bancorp, Wells Fargo, Bank of America, and Goldman Sachs. The rare "strategic investors" that also have tax appetite include large corporations such as Berkshire Hathaway, Google, or Amazon for whom energy is a core corporate concern but whose energy project-related deductions and credits aren't sufficient to trigger tax losses or corporate AMT. Most large utility holding companies that have large renewable energy businesses have amassed vast tax losses and accumulated credits and thus have no tax appetite left (for instance NRG or NextEra).

151 See footnotes above re blocker corps. The SWFs, like Pension Funds, need to form blocker corporations to hold their LLC shares, and though those blocker corporations are technically taxable, excess credits and losses on clean energy investments make taxation at the blocker level a minor issue. It is the withholding tax issue about which SWFs complain.

152 Comello, Reichelstein, Mormann, Reicher et al (2015) p. 26

153 One of the authors was told by a major financial intermediary in wind tax equity structuring that his firm had no interest in simple solar leasing deals. They were too simple and thus transactions fees were small.

154 If a project is certain it can meet the qualification deadlines for a PTC project, it will enjoy decade of credits. If a project isn't certain it can meet these deadlines, bets that Congress will extend the deadline period, and Congress does not do so, then the project is in trouble. Geothermal projects that bet Congress would extend the December 31, 2016 "start of construction" deadline — which it did not do for geothermal projects — are facing this problem.

155 See Burns & Roe "Independent Monitor's Prudency Evaluation Report for the Kemper County IGCC Project" for Mississippi Public Service Commission, April 15, 2014, pp. 5-6.

156 The project typically has an "Operating Company" that owns assets and can execute secured borrowings, with the Operating Company being 100% owned by a Holding Company. It is possible for the Holding Company to execute debt (so-called "back leverage") when tax equity investors are partners at the Operating Company. However, back leverage is both "structurally subordinated" and unsecured, so rates are much higher than if the borrowing could have been executed at the Operating Company.

157 The ITC is "earned in", one-fifth each year. So if the project changes hands during Year 3, 2/5ths of the ITC is not clawed back and the other 3/5ths is clawed back (by means of treating 3/5ths of the ITC as taxable income).

158 See ARRA "Division B-Tax Unemployment, Health, State Fiscal Relief, and Other Provisions — Title I-Tax Provisions" Section 1131.

159 IRS interim guidance in IRS Notice 2009-83. Legislation was introduced in Congress to compel the IRS to undertake the rulemaking. H.R. 6295, "The CO_2 Regulatory Certainty Act."

160 See Federal Register p. 75064, December 1, 2010 "40 CFR Parts 72, 78, and 98 Mandatory Reporting of Greenhouse gases: Injection and Geologic Sequestration of Carbon Dioxide; Final Rule."

161 The NRG CCS retrofit of the Parish coal plant may be able to claim the credits. The Kemper CCS project is now planning to run on natural gas and thus could not obtain the credit.

Chapter 10: Investment Framework Risk — Debt Regulation, Equity Disclosure, and Currency

A recurring theme of this paper has been that clean energy projects are highly capital intensive and require stable, long-term financing to be successfully developed. Both the World Bank and the OECD have launched major efforts to remedy the lack of long-term capital, especially in the developing world.[162]

This chapter discusses three risks that prevent clean energy projects from obtaining stable long-term capital:

1. *Debt regulatory issues that tend to shorten the available term over which clean energy projects must repay their lenders, thus raising interest rate and default risk, and driving away equity investors;*
2. *Climate-related risks of high carbon-emitting companies that are under-disclosed and thus diminish the relative attractiveness of equity investments in clean energy; and*
3. *Currency exchange rate risks that discourage investors based in "hard currencies" from investing in countries with more volatile "soft" currencies.*

10.1 DEBT REGULATORY ISSUES THAT HARM CLEAN ENERGY BORROWERS

The main finance problem for clean energy project developers is often not the ability to borrow money, but rather too little time to pay off the borrowed funds. If clean energy investing were not so generally risky, borrowers could obtain investment-grade ratings and access to long-term fixed-rate bond markets. Most clean energy projects cannot obtain investment-grade ratings and are thus relegated to bank loans with shorter terms and floating rates. When a clean energy project can only obtain short-term loans: (1) only a small amount of debt can be paid off in a limited period, reducing maximum borrowing size; (2) this causes developers to have to raise more equity, which drives up the blended financing cost for a project because equity is more expensive than debt; and (3) potential equity investors bear disproportionate risks by having to defer returns during accelerated debt repayment and lose the time value of money.

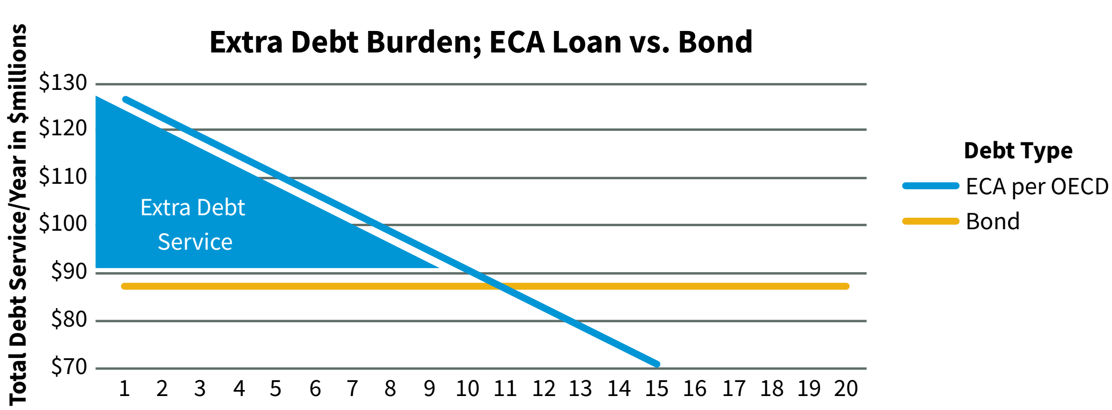
10.1.1 BIS, BASEL III, AND THE NET STABLE FUNDING RATIO

Clean power projects have been hampered in their ability to obtain debt with long repayment periods as a result of actions by both the world's central bankers and various Export Credit Agencies. Bank regulators have made it harder for commercial banks to extend long-term loans to projects of all kinds. The world's central banks harmonize bank regulation globally by acting through the Bank for International Settlements (BIS) in Basel, Switzerland. In three major waves, beginning with the "Basel I Capital Accord" in 1988 through the "Basel III Capital Accord" in 2011, the BIS worked to have stronger equity cushions in case of losses in their loan portfolios. In the 2008 financial crisis regulators realized that a lack of liquidity in banks was a major de-stabilizer because banks couldn't turn long-term loans into short-term cash fast enough. To reduce this risk, BIS in 2014 promulgated the Net Stable Funding Ratio (NSFR) rule that required that at least 85% of the funding for long-term loans to projects come from intermediate-term loans from non-depositors.[163] The IEA, reflecting on this change for energy projects, observed in 2014 that "[o]ne unintended consequence of Basel III's focus on short-term liquidity is likely to be an increase in the cost of long-term energy financing, accompanied by a reduced readiness of banks to issue long-term corporate and project finance loans."[164]

10.1.2 EXPORT CREDIT AGENCIES AND "THE ARRANGEMENT"

To the extent energy projects cannot negotiate sufficiently long-term funding from commercial banks, it may be able to arrange Export Credit Agency (ECA) financing if the project is importing equipment or signing an EPC contract with a foreign contractor. ECAs are government-sponsored lenders of OECD countries, such as the U.S. Export-Import Bank that make their countries' exports more competitive by providing buyers with long-term loans or loan guarantees.[165] The ECAs maintain a cartel-like agreement under the auspices of the OECD, called "the Arrangement" that keeps them from undercutting each other by offering longer payback periods and larger loans. The Arrangement, therefore, has strict limits on loan final maturity, loan average life, and amount of "local costs" that can be financed.[166] For a clean energy project that takes 3 years to build, the best OECD-compliant ECA repayment terms calls for *level principal payments* over 15 years after completion, as opposed to a more desirable *level debt service* over 20 years following completion.[167] For a $1 billion borrowing, Figure 17 below shows the annual payments on a loan financed under the OECD limits compared with a bond issue. The result is that a clean energy project financed with this ECA loan would have to collect an extra $40 million from customers in its first year of operation, making the project less feasible.

FIGURE: 17. Extra Debt Burden; ECA Loan vs. Bond



10.2 EQUITY RISKS OF HIGH CARBON EMISSIONS NOT ADEQUATELY DISCLOSED

When clean energy projects or public companies seek to raise funds from equity investors, their success turns, in part, on being more attractive to investors than other public and private equity opportunities. As part of the overall "energy sector," clean energy companies and projects often compete head-to-head for funding with both companies that emit disproportionate amounts of CO_2 per unit output, e.g. power plants, and also companies that monetize existing fossil fuel reserves, e.g. oil companies. To the extent these fossil-oriented companies are not required to disclose how their carbon-intensive business strategies might fail if emissions are controlled or taxed, these companies have an advantage in fundraising.

More directly, the fossil fuel sector is a major competitor to clean energy in both financial and product markets. This competition remains reasonably strong, even under the IEA's most climate-friendly 450 Scenario. The IEA still shows $11 trillion invested in oil production and $7.5 trillion invested in natural gas from 2016-2040.[168] Cheap equity funding for fossil energy projects can crowd out financing of green energy investments. By the same token, if under-disclosed fossil-related risks raise the attractiveness of fossil stocks relative to greener stocks, then fossil products — from coal-powered electricity to gasoline at the pump — may be underpriced relative to greener electricity and electric vehicles using it.

10.3 LACK OF ABILITY TO HEDGE FOREIGN CURRENCY RISKS

Currency risk is a serious problem for Foreign Direct Investment (FDI) in countries such as the BRICs and in many other large, carbon-emitting developing countries such as Indonesia, Mexico, and Nigeria. A power plant or transmission line is hard to re-possess, so once built its value is to generate cash — in local currency — where it sits. Utilities in Asia or South America bill in renminbi, rupees, or reals, rather than pounds, Euros, or U.S. dollars (USD). Thus, these utilities want payments pursuant to power purchase agreements fixed in these local currencies, even if the plants are financed by foreigners. However, institutional investors want the opposite, i.e. they must generate hard currency to pay American retirees in pension funds or German insurance policy beneficiaries. These investors want to be paid in either hard currencies or know the exact rate at which they can convert local currency. Figure 18 below shows the last decade's history in BRIC currency units, specifically the local units needed to buy $1 (the higher the number, the less the local currency is worth) and demonstrates why investor concerns about currency risks are well-founded.

FIGURE: 18. Local Currency Needed to Buy $1USD in BRIC Countries 2007-2017

	2007	2017	Low Value vs. USD	Decade Change[169]
Brazil Reals	1.8	3.1	4.17	(72%)
Russian Rubles	25	57	82	(128%)
Indian Rupees	40	64	68	(60%)
Chinese Yuan	7.5	6.5	7.5	+13%

Foreign owners of projects in countries with weak currencies have sometimes tried to protect against devaluation by "dollarizing" power contracts. The power purchaser agrees to take the currency risk, by paying for power priced in USD or the local currency equivalent to pre-set USD prices at the time. For stable countries that have pegged local currencies to hard currencies (e.g. the Hong Kong Dollar or Chilean Peso) this strategy may well succeed. But when this strategy fails, it tends to fail spectacularly by turning a continuous risk, i.e. currency devaluation over time, into a single-point catastrophic credit risk, i.e. the local currency falls so far that the power buyer can no longer afford to pay. For example, the Paiton coal-fired power plant in Indonesia was wiped out by the fall of the Indonesian rupiah (IDR) in the 1997 Asian financial crash. The national utility (PLN) had effectively "dollarized" the power purchase contract by agreeing to pay whatever fluctuating quantity of IDRs would be worth USD $0.06/kWh. The IDR declined to 1/7th of its starting value in in the Asian crash, requiring PLN to correspondingly increase its IDR payments sevenfold. This was impossible for PLN's ratepayers leading to a default.[170]

10.4 SOLUTIONS

10.4.1 LONGER-TERM FINANCING

The ability of decarbonization projects to obtain longer term financing could be improved with serious engagement between governments focused on the climate challenge and the parties that write banking and ECA rules. If governments instructed their central bankers to work towards the twin goals of maintaining financial stability and staving off climate change, the bank regulatory conversation would be different. With this direction, the BIS could alter rules in favor of clean energy loans, especially in the case of projects with some form of government support or mandate. For instance, clean energy loans could be placed in a safer BIS risk category for purposes of calculating a lender's "risk-weighted assets," lessening the equity needed to be set aside in relation to the loan and resulting in a cheaper loan.

In "the Arrangement" that controls competition among international ECAs, OECD countries have focused on avoiding undue competition with private banks and maintaining a level playing field among exporter countries. If OECD member countries gave climate concerns greater consideration, then their ECAs could, for example, be empowered to offer fully amortizing, longer-term loans for clean energy projects, and a broader range of projects could be funded.

10.4.2 BETTER CARBON DISCLOSURE

Anything that tends to level the playing field for raising equity reduces financing risks for clean energy. Clean energy developers could raise equity more easily with better disclosure standards regarding the carbon intensity of industrial fossil fuel users as well as on reserve valuation risks of fossil fuel producers. The compliance/disclosure burden would not necessarily be high in comparison to current disclosure protocols. In 2010, the SEC issued guidance clarifying existing requirements for companies already subject to SEC reporting in order enhance the level of disclosure on climate-related concerns and potentially requiring increased SEC scrutiny.[171] In a different vein, companies dependent on carbon-intensive inputs already have to report emissions at individual facilities under the EPA's GHG reporting systems. One major improvement would be to aggregate the statistics in a meaningful, company-wide manner. In the power sector, many utilities already provide useful carbon emissions information, sometimes voluntarily, or in compliance with state or federal requirements.[172] Other carbon-intensive industries could be directed to follow suit. For example, the Sustainability Accounting Standards Board suggests better disclosure for the steel industry.[173] Companies that invest in cleaner steel making techniques might find it less difficult to raise equity if more carbon-intensive steel companies were to provide more complete disclosure. The SEC already compels oil and gas producers to calculate a Standardized Measure of reserve values: the Present Value at 10% (PV10) of future net cash flows forecast to be generated by various classes of reserves.[174] In view of the existing comprehensive disclosure required, calculating additional carbon-constrained reserve valuation scenarios may not be difficult.

10.4.3 IMPROVED CURRENCY HEDGING

Executing long-term currency hedges is the preferred mechanism for mitigating currency risk, but this solution is hampered by lack of markets and inadequate capitalization of the institutions that have sought to create hedging solutions. Long-term currency swaps are easy if one is hedging between two major hard currencies, e.g. Yen and USD. However, there is often no market for weaker currencies. As a 2015 report from the International Institute for Sustainable Development (IISD) concluded: "[I]n many markets, basic currency hedging instruments are not available. In other cases, some form of derivatives market may exist, but there is no meaningful liquidity to trade these securities. Alternatively, the market may be too thin, resulting in very large bid/offer spreads, making hedging uneconomical."[175]

Some efforts are being made to address the currency risk problem, but the amounts hedged to date have been minuscule compared with the tens of trillions of FDI likely required to fund the carbon mitigation investments of non-OECD countries with weaker currencies. The International Finance Corporation (part of the World Bank) reported in 2008 that it had "used derivatives to provide local currency financing for 152 projects in 21 countries for over $4.8 billion."[176]

Some admirable smaller-scale efforts have been recently attempted such as The Currency Exchange Fund (TCX) whose shareholders include the World Bank, EBRD, KfW, JBIC, and others. "TCX operates on a principle of 'additionally', meaning it provides its hedging products only for currencies and maturities that are not effectively covered by commercial markets." However, since 2008 TCX has hedged only $1.5 billion of loans.[177]

Some suggested solutions to the currency-hedging problem while admirable may well be unrealistic. IISD's main solution is to develop larger local currency bond markets to reduce the need for currency hedges,[178] an idea also endorsed by the World Bank.[179] This begs the question of who will buy this new volume of bonds in countries that have scarce pools of savings. If the answer is foreign investors, they are only likely to buy large volumes of local currency bonds to the extent that they can hedge their exposures back to dollars. In that case, the creation of a large local currency bond market would not eliminate the need for currency hedges, the issue that generated the proposed idea in the first place.

That said, there are cases, like China, in which the pool of savings is large, but in which savers are often driven to state-owned banks because of the often thin liquidity and opaque disclosure in the Yuan-denominated bond market. The Chinese state banks have a reputation for making unproductive loans to poorly designed projects and failing companies while shying away from extending credit to private companies. Conceivably, if the Chinese bond market were reformed, existing Chinese savings might shift out of the banks toward the bond market, where private clean energy projects could obtain long-term bond funding not now available from the banks.[180]

ENDNOTES - CHAPTER 10

162 See World Bank's "Global Financial Development Report 2015-2016: Long-Term Finance", as well as OECD's "Institutional Investors and Long-Term Investment—Project Report May 2014."

163 This is a vast oversimplification, but captures the main point of the rule. "Basel III: The Net Stable Funding Ration", Basel Committee on Banking Supervision, October 2014. http://www.bis.org/bcbs/publ/d295.htm

164 IEA, 2014 World Energy Investment Outlook, p. 39.

165 Many of the Export Credit Agencies (especially under the Arrangement's terms) will only to lend or guarantee a portion of the funds borrowed, requiring commercial bank loans to provide the rest of the loan (with no guarantees from the ECA). Additionally, the ECA will demand that the ECA's own credit exposure is amortized pro rata with the unguaranteed commercial bank tranche. Thus, if a bank will only give a C+7 loan (construction plus seven years), the ECA will similarly restrict itself to that short tenor — even though the ECA is allowed to do a C+15 loan under the Arrangement. This is a "lowest common denominator" problem that wipes out the long maturity benefit of the ECA borrowing.

166 See OECD Arrangement, "Annex IV: Sector Understanding on Export Credits for Renewable Energy, Climate Change Mitigation and Adaptation, and Water Projects", Chapter II: Provisions for Export Credits, p. 98.

167 This is a very important distinction. The OECD Arrangement requires that a *level amount of principal* be paid back in each year, and since early-year interest payments are very high (because 100% of the principal is initially outstanding) that level-principal requirement leads to a *highly front-loaded set of total annual debt payments*. A normal project financing is similar to a home mortgage, with principal payments set small in early years and large in late years, causing the total annual principal and interest payments to be equal over the entire repayment of the loan.

168 World Energy Investment Outlook 2014, p. 162.

169 Change defined as (2007 value — 2017 value)/2007 value.

170 Rajeev Sawant, "Infrastructure Investing: Managing Risks & Rewards for Pensions, Insurance Companies & Endowments", Wiley, 2010. P.

171 https://jenner.com/system/assets/publications/1696/original/Environmental_Issues_in_Bus_Trans_Chapter_15_SEC_Disclosure.pdf?1319653867, p.462

172 See e.g. Puget Sound Energy's 2017 10-K, p. 25, "PSE's Greenhouse Gas Reporting."

173 https://www.sasb.org/wp-content/uploads/2014/06/NR0301_ProvisionalStandard_IronSteelProducers.pdf See p. 5 and Table 1 on p. 8. SASB doesn't exactly specify a lifecycle CO_2/ton product measure, which is what investors need.

174 For example, see Apache Corp. 2016-10k, page F-59 "Future Net Cash Flows." https://www.sec.gov/Archives/edgar/data/6769/000167337917000004/apa10-k2016.htm

175 International Institute for Sustainable Development (IISD), "Currency Risk in Project Finance", August 2015, p. 6

176 "IFC and Local Currency Financing" accessed on line 9/10/2017 at https://www.ifc.org/wps/wcm/connect/51eed100487c9a249cd4bd84d70e82a9/VPU+localcurrencybrochure+5-08.pdf?MOD=AJPERES

177 "Local Currency Matters", dated as "updated January 2013", accessed online 9/10/2017 at http://www.tcxfund.com/sites/default/files/attachments/160113_tcx_overview_global_english_master.pdf

178 IISD page 9.

179 IFC page 7.

180 NY Times, "To Problems with China's Financial System, Add the Bond Market", Dec. 20, 2016. https://www.nytimes.com/2016/12/20/business/dealbook/china-bonds-fall-rates.html?mcubz=3

Chapter 11: Examples of Follow-on Research

The table below provides examples of potential research flowing from the "Derisking Decarbonization" framing paper. The follow-on efforts are necessarily both deep and broad. We must dig in detail into each of the nine investment risks we have surveyed. This will require both *quantitative* (economic, financial, statistical) and *qualitative* (law, policy, politics) work, all informed by relevant technological considerations. We also must look at the interactions among these risks, and how they may compound upon each other because even well-conceived decarbonization projects may be scuttled by multiple problems. We must also explore the investment universe in which clean energy project finance occurs: the size and scope of investments needed; the institutional inflows of investible capital; the acceptable quality parameters etc. Of course, clean energy investment is a *global* imperative and we must, therefore, pursue the research above with respect to both developed and developing countries, especially higher carbon-emitting nations and regions. Finally, in the "Derisking Decarbonization" framing paper we proposed some brief solutions to the investment risks identified. In follow-on research, we need to explore these and other proposals in depth, as well as barriers to their adoption. Some truly excellent solutions may be impossible to implement, while others that appear to be panaceas may not be, on closer inspection.

FIGURE: 19. Some Examples of Potential Follow-on Research

	Taxpayer Investors	Non- Taxpayer Investors
Introduction	Size of Investment Needed	Compare IEA vs. other experts; quantify funds freed up through reduction in high-carbon investments
	Institutional Flows	Analyze investor subcategories to eliminate double counting (interviews with OECD, ICI, SWFI, IMF, World Bank); strip out asset valuation in some data (insurance); incorporate appropriate amount of bank lending capacity
	Wealth vs. Climate Spending in Non-OECD	Better data on wealth in BRICs and other non-OECDs, since information is poor in OECD and other databases.
	Offsetting Factors	Investigate macroeconomic boost from clean-energy spending vs. drag of repaying clean energy investments
Markets	Electricity Market Design	Investigate market design in "competitive markets" expanded to include EU and Australia; compare best practices in fully-regulated states, provinces or nations
	Fossil Fuel Prices	Implementation issues for CfDs involving natural gas and oil; impact on privately-traded commodities markets
Policy	Mandates and Carbon Pricing	Leakage issues in carbon pricing systems for single states, provinces, countries; evaluate carbon abatement cost impacts of high-cost complementary measures interacting with carbon pricing; compare RPS approaches
	Government Subsidies	Evaluate credit aspects of best practices/design in electricity market CfDs for low-carbon; data analysis – grants vs. loans
Project Development	Innovative Technologies	Policy changes to increase gov't involvement in developing bankable standard designs in bulk storage, CCS, nuclear etc.
	Government Approvals & Permitting	Global envt'l benefits vs. local impacts in environmental laws (e.g., NEPA); specific permitting, PPA, transmission issues
Investment Framework	Rule of Law	Bilateral vs. multilateral investor protection treaties under auspices of climate agreements; mandatory arbitration
	Tax Issues	Bilateral vs. multilateral investor protection treaties under auspices of climate agreements; mandatory arbitration
	Debt Regulation, Equity Disclosure, and Currencies	- Capital adequacy rule changes - Equity valuation impacts of climate disclosures - Frameworks for soft currency hedging