TRUE GREEN CAPITAL

The Impact of Oil Prices on Solar Power Plant Economics

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Overview

This paper discusses the sources of revenue for solar power plants and explores the relationships between oil, natural gas and solar electricity power generation. At the end of the paper we address specific questions posed by investors.

Key Points made in this paper:

1. C&I solar power plants are primarily driven by power and natural gas infrastructure costs (i.e. transmission and distribution and gas pipeline capital costs) and NOT by crude oil prices and only marginally by natural gas prices
2. SRECs are inversely correlated to power prices, i.e. reductions in power prices result into increases in SRECs, therefore keeping the overall solar power plant returns relatively constant
3. The great majority of a typical portfolio power revenues are in fixed price contracts

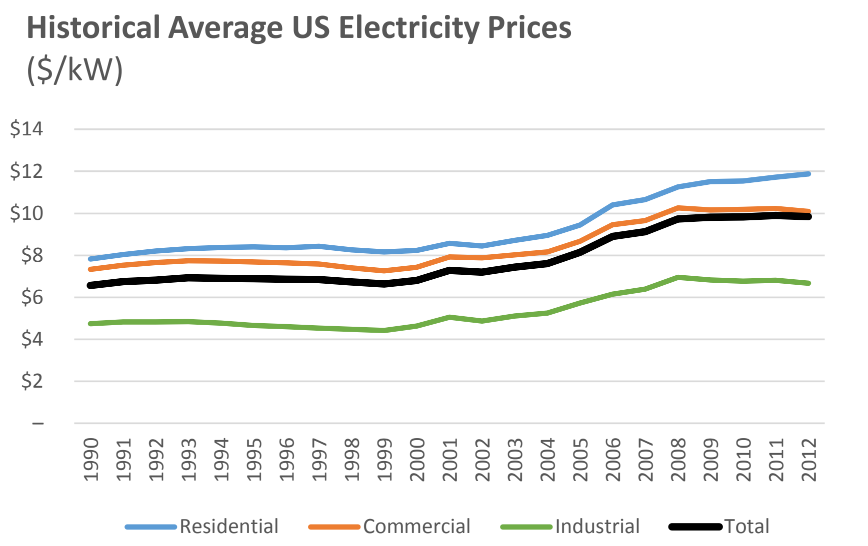
Solar Generation Projects and Sources of Revenue

Solar power project revenue is driven by two sources:

1. Sales of power under a long term (typically 20 year) contract and, additionally
2. Sales of Solar Renewable Energy Credits (SRECs) (see definition below). Depending on the State where the project is located, SRECs can be secured either (a) through 10-25 year long term contracts, or (b) through short term commodity-like markets.

TGC Power Purchase Agreements

As the chart below shows, a long view of power prices show almost no volatility or cyclicality and average year on year increase of approximately 2% p.a. which is consistent with long term inflation during the period.



Source: Energy Information Administration

Typical solar C&I projects that have long term agreements (a "PPA") for the sale of power (or net metering power credits) at a known fixed price. These agreements are typically 20 years and range between 10 and 25 years. We only sign contracts with high credit quality counterparts that are typically rated. For example, the TGC current ~50 MW portfolio has a weighted average rating of A. Solar market PPAs tend to approximately 20% less than the retail price of the counterparty at the time of execution. The 20% discount provides an incentive for the transaction and the fixed nature of the contract provides the counterparty with some future protection against future price volatility.

As an example a typical investment portfolio has fixed price PPAs for the majority of its power revenues. In that respect once a PPA is signed there is no future price risk and all the risk has been turned into credit risk. There are two exceptions to the above that correspond to a small minority:

1. *MA Municipal Market*: This market operates through floating price PPAs that are based on a discount against the G-1 rate. Typical PPAs have a floor of 8-10 c/kWh (equal to approximately 40% of the current G-1 rate) which eliminates downside price risk.
2. *PJM Interconnected Power Plants***:** Any power plants that are interconnected to the transmission network in PJM receive wholesale prices. These assets do have the ability to sell forward power for up to 13 years. Similar to a typical PPA, this means the asset can enter into a fixed price contract, again translating price risk into credit risk. However, for these projects, SRECs represent approximately 75% of revenue; as a result, the impact of power price fluctuations in these projects is not particularly significant. For example, if power prices were to drop by 50% versus current prices for the life of the project (i.e. 20 years at ~1.5 $/mmbtu natural gas prices) then the impact on the projected unlevered pre-tax IRR would be an approximately 1.6% reduction.

What follows is a broader discussion of how power prices are set. Data sources, analysis and analyst reports that back-up the data presented can be provided.

Overall, **distributed solar power plant power economics are driven by power infrastructure costs while commodity prices have limited impact on PPA prices**. Even if nuclear, coal and/or natural gas commodity prices were zero, the price paid for electricity by the customer of a distributed solar power plant will be reduced by ~25%. The modest price reduction is largely due to transmission, distribution and gas pipeline transportation costs associated with these other resources, as further discussed below.

In a typical distributed solar power plant investment a 25% reduction in PPA pricing corresponds to an approximately 2-3% reduction of IRR for investments in our base case (yield 9-12% of unlevered pre-tax IRR). What follows summarizes the drivers of power prices that underline this overall conclusion.

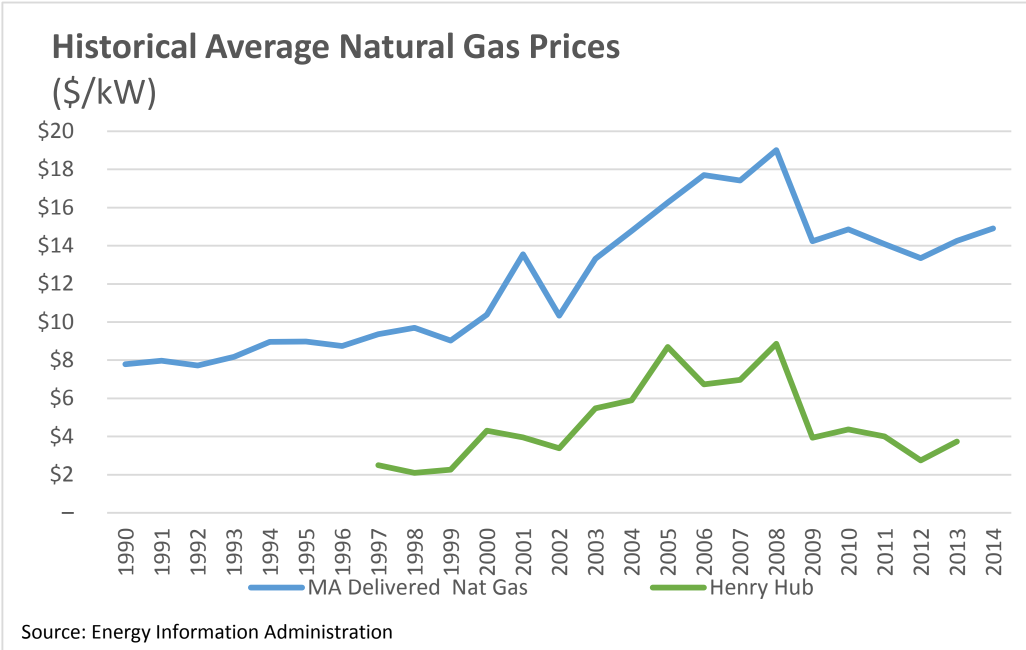
US power markets are generally deregulated with varying degrees of competition that sets prices. Broadly speaking, competition centers on power prices and consumer acquisition while the "wires" (i.e., transmission and distribution) are regulated with costs set by each state's Board of Public Utilities ("BPU") and shared by the consumers. Most solar power plants receive the retail price (as opposed to wholesale) which includes the transmission and distribution element. This is because distributed generation sources alleviate power bottlenecks and reduce future investments in transmission and distribution infrastructure. This is particularly relevant for the US Northeast where is it practically impossible to build new power transmission or gas pipelines to support new gas power plants. Given the above the power prices paid by consumers and that are relevant to distributed solar are driven by three factors which are power (~25% of total delivered price), transmission and distribution (~50% of the total delivered price) and natural gas transportation (~25% of the total delivered price):

1. <u>*Cost of power generation*</u>*:* This includes fuel, O&M and Capex. In times of oversupply the power prices are set by the marginal fuel which is natural gas. In times of tight supply and demand (typically within 15% reserve margin) prices are set by the cost to build a new power plant. These costs are driven by materials and labor and have been generally increasing with inflation**. It should be noted that *crude oil has practically no impact on US power prices* as less than 1% of total power generation in the US is oil and most of it is located in "islands" where there is no coal or natural gas.** Finally, a concerted effort to close coal and nuclear plants will inherently result in a need for new generation. Solar and natural gas are the obvious choices; of the two, solar can be implemented a lot faster and at a lower cost given extended permitting timelines for natural gas plants (often 2-3 years) and gas pipeline transportation constraints.

2. <u>*Cost of Transmission & Distribution ("T&D")*</u>*:* T&D is driven by O&M and Capex which generally consists of labor and materials. As such, T&D costs have historically increased with inflation. After many years of T&D underinvestment many utilities in the Northeast have embarked on T&D Capex programs leading to increased rates across the Northeast. In CT and MA, ratepayers have experienced 10-25% overall rate increases since the last quarter). Superstorm Sandy and other recent weather events in the Northeast have also contributed to T&D increases.

3. <u>*Cost of Natural Gas transportation:*</u> Pipeline cost in the Northeast and California makes up a significant portion of the natural gas price used for power generation. Given pipeline constraints in the Northeast as well as peaking demand in the winter and summer, transportation costs are typically 50-80% of the delivered natural gas price. In MA, NY and CT, in particular, delivered gas has been as high as ~15 $/mmbtu when the commodity is priced at ~4 $/mmbtu at Henri Hub.

The chart below shows the historical difference between MA delivered natural gas prices and Henri Hub prices underlying the significant impact of transportation on commodity prices:



Like power plants, the cost of pipeline capacity is also driven by supply and demand, O&M and Capex, each of which tend to be inflation driven. Pipelines are historically difficult to permit and build; as such, it seems unlikely that the currently tight supply situation in the Northeast will be alleviated in the next 5-10 years

Solar Renewable Energy Credits

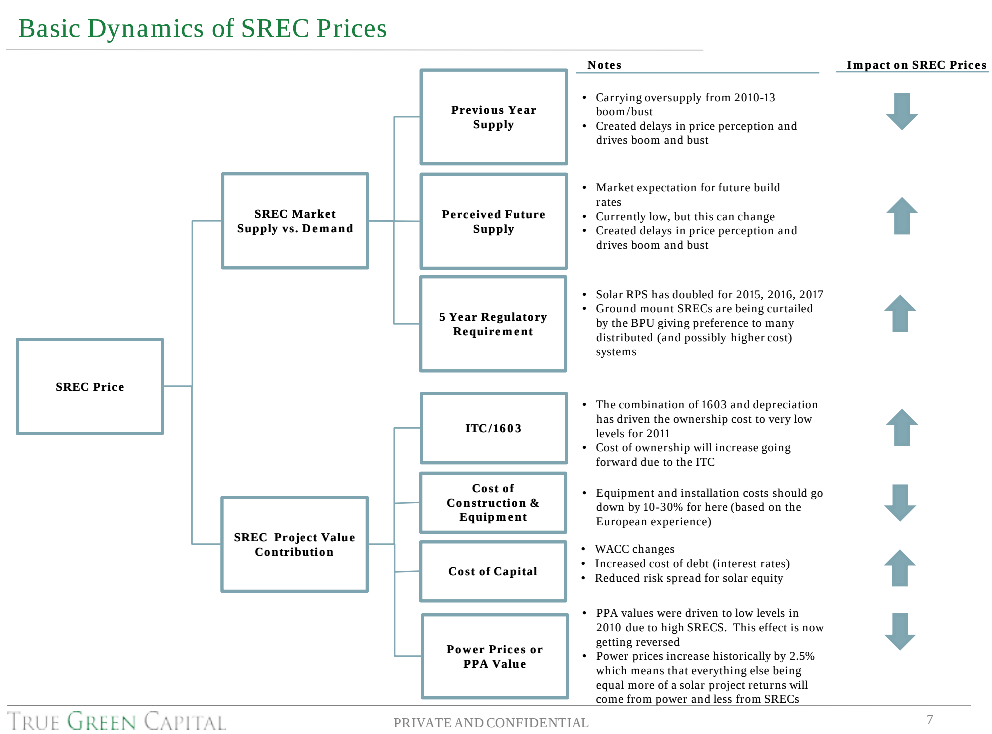
SRECs exist in states that have Renewable Portfolio Standard (RPS) legislation with specific requirements for solar energy, usually referred to as a "solar carve out". SRECs are produced each time a solar system produces a pre-defined amount of production. The RPS dictates required annual levels of energy derived from renewable sources as a percentage of total retail electricity each year on a state by state basis. Implementation of the RPS is based on market mechanisms where market participants trade the SRECS. Any US producer of solar electricity within the 29 participating states is issued an SREC which counts as a certification to having produced 1MWh of electricity through a solar source. Depending on the state SRECs are either "bundled" with power under 10-25 year fixed price contracts and are sold to the local utilities, or just like stocks SRECs are sold on the open market at varying prices correlated to demand. In certain SREC markets the issuance of an SREC is independent of (not bundled with) the power purchase agreement, in which case the market is referred to as an "unbundled" market. As an example, Vermont and Rhode Island are bundled states while New Jersey and Massachusetts are unbundled markets and regard an SREC as a transferable and saleable asset. Thus, third party owners of solar PV systems within certain states are eligible to sell the SRECs to utilities, which can subsequently utilize the SRECs to satisfy their annual RPS/solar carve-out requirements. Together, a participating state market's RPS and solar carve out result in an SREC market that supports solar development outside of utilities. Each state sets its own RPS standards, solar carve-outs and compliance prices which establish the SREC price in the market.

Furthermore, certain states (e.g. New Jersey and Massachusetts) have implemented long term forward markets (up to 10 years in the future) that allow for efficient hedging of SRECs. It is TGC's belief that market based mechanisms for solar, such as we enjoy in the US, rather than government mandated prices, like Europe, would provide for a stable environment for solar power generation to flourish. Therefore, TGC has focused all our efforts to date on the US market.

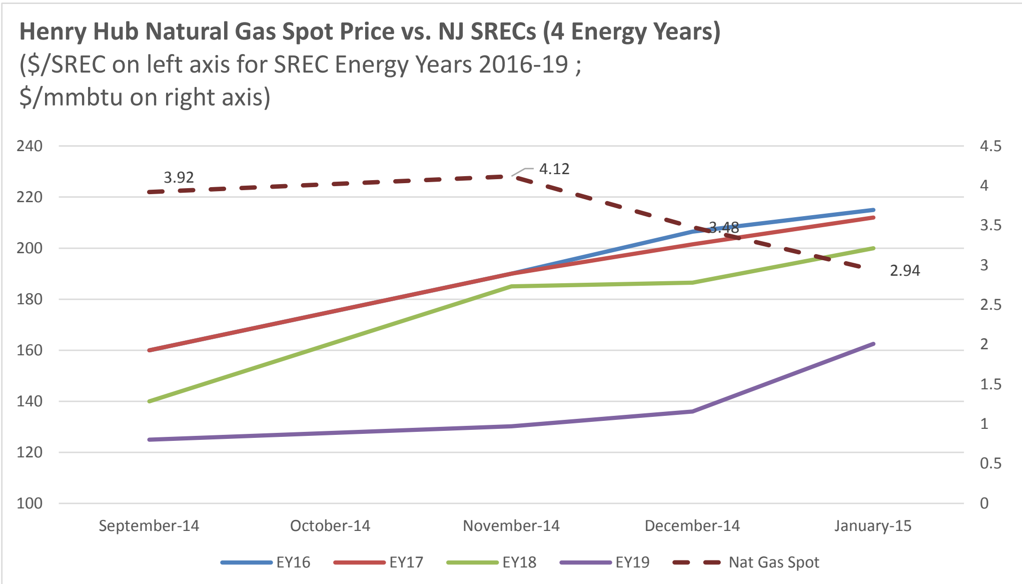
Basic Dynamics of SREC Markets

SREC markets are small in the context of the overall power markets that they operate in. For example the MA SREC market corresponds to 1% of the power market (in energy terms) is expected to be 1.8% by the end of 2015. NJ has similar dynamics with its SREC market being ~3% of the overall power market. The conclusion is that SREC markets are very small and have at this stage insignificant impact on the overall consumer power bills.

We have developed a TGC proprietary view on SREC price evolution. Our analytics model various SREC price drivers and attempt to reflect (a) the equilibria around what we believe to be the important drivers of price, as well as (b) the "boom-bust" behavior that we typically see in commodity markets. The table below shows the drivers behind our models:



SRECs are conceptually inversely correlated with power (and natural gas). This is due to the fact that in a declining power price environment SRECs will have to increase for investors to build enough solar capacity to meet the RPS targets in each state. In fact, this effect has been observed recently in the NJ market, the chart below demonstrates how the NJ SREC forward curve has moved since last September:



Generally, 60-70% of a project's revenue is driven by SREC pricing, which, as we have demonstrated above, is inversely correlated to power prices.

Risk Management of SRECS and TGC's Hedging Strategy

TGC Funds, through each special purpose project owner entity, will implement a portfolio hedging program in managing exposure to SRECs for downside protection and to maximize upside potential. TGC has put in place a hedge book to manage the SREC project exposure in its portfolio. TGC's senior executives are well versed in commodities and deeply experienced in the SREC market. This capability has allowed TGC to implement a formal process for the management of SREC risk by selling forward a portion of the SREC portfolio to protect potential downside risk while maintaining a small percentage of SRECS as "floating" to capture potential upside and to enhance returns. TGC believes that this competency and skill is integral to the investment management process in structuring a portfolio of solar energy projects to achieve the most favorable risk/return profile. We see this as a significant competitive advantage that allows TGC to create projects with fixed revenue streams in otherwise volatile markets.

The following table on the next page expands on these revenue sources, the related risks and how TGC manages risks associated with these revenue sources.

Revenue and Related Financial Risk Mitigation:

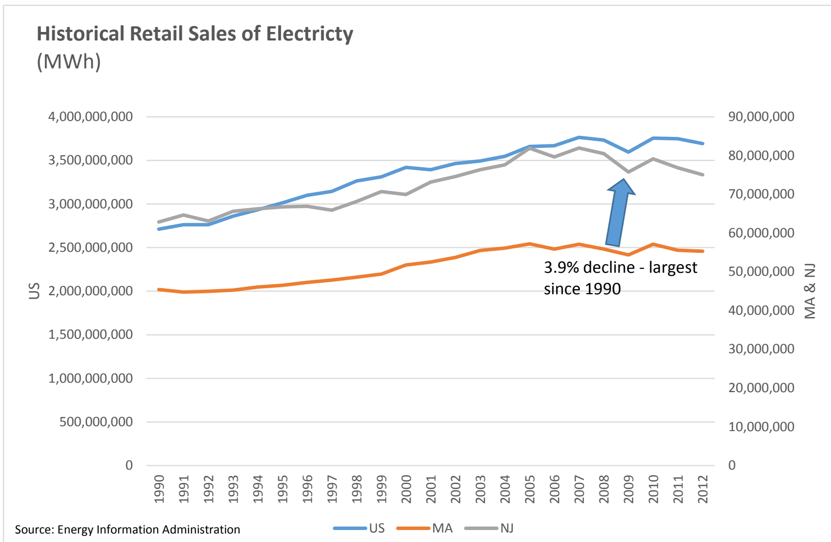
Risk Driver	Description	Risk	Potential Size and Impact	TGC Mitigation Strategy	Comments
Power Sales Contract also referred to as the Power Purchase Agreement ("PPA")	Long term (15-25 years) fixed price contract typically with a 1-3% price escalator	Contract counterparty default and/or bankruptcy	• Depending on the state the power contract represents 35-100% of the total project revenue • In all states the utility has an obligation to buy the power due to Net Metering Rules at the wholesale price which is typically 10-20% lower than a TGC contract. The impact of such a sale for the life of the project would reduce levered pre-tax IRR by 2-5%.	• Projects are financed with credit-rated or credit-worthy off-takers • We perform detailed credit analysis on all our hosts and especially private credits • We operate only in states with supportive Net Metering Rules where utilities always provide a back-stop • As part of our portfolio strategy we also operate in Massachusetts that allows for Virtual Net Metering which means that you can sell to any power consumer in the state. In an event of default we can then not only sell to the utility at wholesale prices but also to other customers at a better that wholesale price.	We only have to manage credit risk
Sales of Solar Renewable Energy Credits (SRECs)	Depending on the state 15 year fixed or variable price credits	Price volatility for states that have short term credits	• Depending on the state the SRECs contract represent 0-65% of the total project revenue • If SRECs were to be zero for the life of the project a typical project would return capital but have zero or a very low IRR. This is highly dependent on the state as there are states where solar is "grid competitive" and SRECs are not required to produce attractive IRRs	We manage this risk through a portfolio approach that minimizes the impact of a zero SREC price scenario while increases the potential upside of the portfolio : • We have put in place a diversified portfolio of projects that includes states that have no SREC price risk such as RI, CT and VT • We structure our portfolio to achieve an 8% downside case scenario assuming SRECS are zero • We hedge forward a portion of the SRECs in our portfolio.	• We develop on a regular basis proprietary research and quantitative models that analyze the drivers of SRECs and the potential SREC evolution by state • We manage an SREC hedge book • We have developed the legal contractual expertise to put in place SREC contracts that add significant value to our portfolio at a low cost (e.g. we have built volumetric optionality in our contracts to protect us from construction delay risk and production risk)

Answers to Specific Questions

Question 1: How does power usage correlate to value of SRECs? For example, if the state of MA uses 20% less electricity in 2015 than in 2014, would we expect the price of SREC to fall as utilities would need less SRECs since they are producing less power?

Answers:

1) Please see section above that discussed correlation between SREC prices and power. The correlation is inverse, i.e. lower power drives higher SRECs
2) The number of SRECs are "fixed" in the MA system, i.e. changes in power consumption will not change the number of required SRECs or their price dynamics. Furthermore, SRECs in MA have a price floor of 285 $/SRECs and we are modelling our projections based on that floor
3) See chart below for power consumption in the US:



A 20% reduction in power consumption is very unlikely unless we have a major demand disruption (war, significant economic depression, etc.). The highest reduction we have seen since 1990 was a 3.9% decline in 2008 due to the recession. If you maintain the view that lower electricity prices are on the horizon, such prices will increase power consumption and will also increase SREC prices for the reasons discussed earlier in this paper.

Question 2: Can the government change the law so that utility companies are required to purchase less SRECs than they are today? If there is a ratio set and for every kW of "fossil fuel" energy produced by a utility company they have to purchase x number of SRECs. Can future regulations change this ratio, thus reducing the demand for SRECs and hence the price of SRECs? I assume this would impact the value of unhedged SRECs.

Answers:

1) *Past Allocation of SRECs:* Federal or State governments can pass any legislation based on the appropriate procedures for *matters going forward*. To our knowledge there has never been any retroactive claw-back on SRECs and in general there is no precedent on retroactive legislation.

2) *Future Allocation of SRECs*: To change forward SREC regulation requires three layers of government, federal, state and state Board of Public Utilities. We have no information at this point that would point to any detrimental changes to forward SRECs. We believe it is unlikely that such a regulatory change would occur given that solar markets are well-established components of state economies. In fact, the opposite has occurred as many states have expanded solar requirements and incentives. Given the complexity of decision making and need for consensus we will have significant time to make decisions on whether or not we want to invest in future SREC projects.
3) *Impact on Unhedged SRECs*: to impact unhedged SRECs one has to change the RPS for the vintage of such SRECs (i.e. for the year that the project was placed on line). That will require a retroactive change in law which as we have already discussed is extremely unlikely.

In any case we always hedge enough SRECs to lock in a 9-10% unlevered IRR project even if the unhedged SRECS were zero.

Question 3: For the SREC's you plan to hedge, who is our counterparty? What is the counter party risk?

Answer: Our counterparts are rated investment grade credits or fully guaranteed subsidiaries of such credits. We need such credits in order to lever up the projects and only such credits are acceptable to bank debt lenders.

Question 4: How does cheap natural gas and thus, cheaper electricity, impact PPA's without floors?

Answer: please see PPA and power price discussion earlier in this document. To summarize, 95% of current PPA revenues are hedged.

Question 5: On the PPA agreements with fixed prices and/or floors, are they required to typically purchase a certain amount either in kW or as % of what the facility produces?

Answer: our PPA counterparts are contractually obliged under the PPA to take all the power that the power plant produces, or at least 110% of the expected output. This is one of the points that make the PPA bankable.

Question 6: Assuming oil and natural gas prices stay at their current levels for the next ten years ($45 oil and $3 natural gas), how does that impact the investments we have already made and future investments with True Green? How much would this impact unlevered IRR's on investments? What about at $30 oil and $2 natural gas? I understand that the cost of power is comprised of distribution and transmission costs, but there is some portion impacted by natural gas prices.

Answer: please see PPA and power price discussion earlier in this document.