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Electric Utilities:
Perhaps not the Investment One Expects

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OVERVIEW

Shares of electric utility companies have performed very well thus far in 2014. For example, the $700 million iShares U.S. Utilities exchange-trade fund, or ETF (IDU), which has a 70% exposure to electric utilities and 30% in "gas, water and multi-utilities," had returned 16% year-to-date, as of October 21st, and has a 5-year annualized total return of 12.6%. Similarly, the $2.2 billion Vanguard Utilities ETF (VPU), which has a 52% weighting in electric utilities, has gained 15% year-to-date and 12.7% annualized over the past five years. Utilities are widely owned as bond substitutes. There is roughly $10 billion of assets under management (AUM) in domestic utility ETFs (www.etfdb.com). This figure is dwarfed by utility mutual funds: by random selection, just five mutual fund managers (Gabelli, Prudential, Fidelity, Merrill Lynch, and Franklin) have well over $20 billion of AUM in this sector. Utilities are also trading at close to record valuations: IDU currently yields approximately 3.0% (distribution yield), has a trailing price/earnings (P/E) ratio of 21.0x, and a price/book ratio of 1.9x, as of August 31st, 2014, which is considerably above historical valuations[1] for electric utility companies. Similarly, VPU yields 3.3%, with an average P/E ratio just over 20x, and a price/book ratio of 1.7x. At these valuation levels, it appears that a range of disruptive changes in the industry fundamentals are not being priced in and that investors who simply buy these securities seeking income during the current long yield crisis, expecting dividend increases, and generally a "safe" investment, could be vulnerable to a severe valuation contraction. These substantive systemic risks are separate from the significant interest rate risk posed by the historic low dividend yield; if re-priced from the current yield of 3% to merely 4% or 5%, utility investors would experience a principal loss on the order of 25% to 40%.

The electric utility sector has benefited from the dramatic and persistent decline in interest rates over the past 33 years, since the 10-year Treasury Bond reached a yield of 15.3% in 1981, compared to today's 2.2%. Consequently, the cost of capital for utilities (as well as most other debt-financed industries) has declined dramatically and has created a benefit that is mathematically impossible to replicate. It is evident that historical returns cannot be used as a proxy for future returns. Thus, assuming that the future will repeat the past is not a sound investment strategy.

The electric utility sector used to be considerably more regulated than is currently the case. These companies were allowed to earn a guaranteed rate of return based on their capital investments, and they were largely allowed to set the rates accordingly. This is no longer true across the board. While some utilities continue to be regulated—with guaranteed returns on equity of perhaps 10-12%, and a maximum allowed debt/equity ratio of about 100%—other utilities have become "merchant generators," which is the term used for power producers that can charge market rates for their electricity and earn whatever rate of return the market allows. However, the tradeoff for that unbounded return possibility is the loss of the regulated guaranteed return on capital; therefore, those utilities are now subjecting themselves to the risk of losing money on their capital investments. Then there are hybrids: utilities having some business units that are regulated and others that are unregulated. While all three groups are sensitive to rising interest rates—which would increase their cost of capital and potentially result in reduced share prices given that utilities are often purchased

[1] Source: Bloomberg

as bond substitutes—the latter two groups appear to be the most at risk, since the demand for electricity seems to have decoupled from economic growth as businesses and consumers have found ways to reduce their usage.

Perhaps more importantly, the rapid expansion of photovoltaic (PV) panels (also known as solar panels) as an alternative energy source for both consumers and businesses has finally begun to disrupt the electric utility industry—these panels not only displace demand from the grid, but may also be used to supply excess power back to the grid (so-called net-metering). The investing public, having been long accustomed to the failed promises and initiatives of the solar power industry, is hardly aware of the critical mass and economic tipping points that have only recently been reached. Recent growth rates, care of both lower unit cost and the development of effective financing solutions that free the retail customer from any capital investment, are such that 29% of the incremental electric power capacity additions in the U.S. in 2013 were from rooftop solar panel installations. Homebuilder Lennar Corp. now automatically installs, with arranged financing, rooftop panels in new subdivisions in California.

The impact could be particularly severe for those merchant generators operating what are known as 'peaking plants', which operate primarily during times when power use is at its peak—for example, on hot summer days when air conditioning causes electricity usage to reach its highest levels. This is also when electricity prices are the highest, and this happens to coincide with the time when the sun is strongest, and rooftop solar panels generate the most electricity. Consequently, assuming that some modest share of those consumers with rooftop solar panels sell back to the utilities some of the power generated in the middle of the day, the need for peaking plants would be reduced and, perhaps at some point in the not-too-distant future, eliminated. In nations with high renewable power capacity, some European and Australian utilities have recently faced true crisis days, during which electricity prices were temporarily *negative.* In Germany, the most advanced European country in terms of alternative energy production capacity, and which is several years ahead of the U.S. in this respect, the two largest electric utility companies have declined by over 50% during the past five years, or by 15% or more on an annualized basis. For these reasons, the electric utility sector appears to be severely challenged—even though valuations remain close to record highs.

Even exclusive of these two most substantive earnings and valuation risks (technological disruption and interest rates), there are other earnings risks, such as the looming decommissioning expense problem for utilities with nuclear power exposure. Moreover, the identification of the electric utility sector as historically less volatile might actually be an inaccurate finding. The utility industry has, rather, been characterized by lower-than-average volatility generally, but with high-volatility disruptions in discrete, short periods, a pattern that, in historical studies, tends to understate the price risk. Investors in the electric utility sector should seriously reassess their risk and return assumptions about this asset class.

Utility Background

Although most utility customers today are limited to a single power provider, this was not always the case. In the early days of the electric power market, independent generators and distributors competed with each other for customers. As a result, streets were turned into a jungle of power lines. Confusion gave way to consolidation in the 1920s, when large electric power holding companies were formed. By 1932, the eight largest holding companies controlled 73% of the nation's investor-owned electric businesses. Holding companies typically owned several local subsidiaries in different states. With little state regulation, and no federal regulation, national holding companies were effectively unregulated. Some were known to overcharge subsidiaries for equipment and service, knowing that the subsidiaries had to pass their expenses on to customers.

These abuses were corrected with the passage of the 1935 Federal Power Act and the Public Utility Holding Company Act (PUHCA). This legislation created the current regulated rate of return system, under which rates for electricity were set by each local regulatory body: one of the quid pro quos for ceding the possibility of open-ended returns for the guarantee of an adequate, if not superior, return on invested capital. In exchange for the obligation to provide service to all customers in a specific territory, investor-owned electric utilities were given a territorial monopoly on service and allowed to earn a limited profit. In the absence of that guarantee, a utility could not have afforded to extend its costly distribution system to outlying and rural areas. Until the advent of the regulated return-on-capital framework, the only areas of the nation with access to electricity were the densely populated city centers. State regulators have historically set prices at rates that reflect the cost of building power plants and putting up the wires. Profits have reflected the cost of capital.

Until the 1930s, hydroelectric power was responsible for providing most of the electricity, in the U.S. because hydro-plants were less expensive to operate than those that relied on thermal energy released by burning fuels such as coal. Today, hydroelectric plants, which are often located at river dams, are only one source among many for generating energy, now only supplying approximately 10 percent of the nation's energy[2]. Although alternative energy sources such as nuclear, solar, and wind energy continue to gain market share, the primary means of generating electricity in the United States and much of the world is still coal-burning power plants. Coal is burned to convert water to steam, which then turns large turbines that generate electricity. The electricity is then transmitted overhead on power lines to substations at very high voltages. Substations step down the energy to lower voltages, and distribution lines then transmit the energy to individual homes and businesses.

As the electric industry built its infrastructure, public utility commissions (PUCs) were put into place to regulate electric and natural gas companies. The first all-welded natural gas pipeline, over 200 miles in length, was built in 1925 — from Louisiana to Texas. Eventually, some cities chose to operate their own electric and/or natural gas operations, while others left them in the hands of for-profit businesses. The PUC-regulated model for utilities worked well in the United States for many decades. Power companies were able to request rate hikes to cover the construction of new power plants and other costs. PUCs usually granted these hikes because they allowed utilities to build or improve infrastructure (incorporating the

[2] According to the U.S. Department of Energy

inevitable inflation of construction and maintenance costs), and the increased capacity was both needed and resulted in reduced rates in the long run, as the supply met or exceeded demand. Also, it guaranteed power delivery to people living in remote areas, for whom the cost of capital for building their own facilities would have been prohibitively high otherwise. However, after 50 years as a successful model, by the 1980s, construction costs escalated so fast that rate hikes did not result in reduced rates later. The public, as well as government officials, thought that perhaps it was time to deregulate the industry and introduce more competition to the electric power markets.

In 1992, the U.S. Government passed the Energy Policy Act (the "Act"). Among the many changes and regulations it introduced, it created a new type of company in the industry: exempt wholesale generators. These companies could generate power using any method, and they were exempt from the Act's energy efficiency measures. Existing utility companies were required to open their transmission systems to other companies, which were the wholesale brokers. Brokers, which took the form of independent power brokers or new departments in existing power companies, sold cheaper power from one region of the country to another region that needed it. They might also resell the electricity to large manufacturers. All of the sales were on a wholesale basis. No additional regulations were enacted to broaden this model and include retail sales.

The most recent trend in the electric generation industry is to convert coal-burning power plants to natural-gas plants. Natural gas emits much lower quantities of greenhouse gases, and the Environmental Protection Agency has set new levels of permitted greenhouse gas emissions for all newly constructed power plants. Today, nearly 75 percent of the power in the United States is supplied by investor-owned utility companies. The rest comes from a mixture of municipally owned utilities, rural electrical cooperatives and federal facilities.

While investor-owned utilities are regulated by state commissions and the Federal Energy Regulatory Commission (FERC), almost all publicly-owned utilities are regulated by state and/or federal laws, or are "self-regulated" through boards accountable to consumers or elected officials, and some answer to state commissions. In addition, the Rural Utility Service (RUS), a federal entity that provides funding to many publicly-owned utilities, exerts regulatory authority over its borrowers. Federally-owned facilities provide subsidized power to some publicly-owned utilities. Of course, it is in a utility's financial interest to generate (or buy) and deliver as much power as possible. The higher the demand, the higher the investments, and the higher the profitability of the utility. The regulators are very familiar with the incentive system and control the profitability of the utility, not only by setting return on equity (ROE) limits but also debt/equity ratio limits. Currently, the cost of both equity and debt capital is close to historical lows, as evidenced by the utility industry's record-high (trailing) P/E ratio of 21x and low bond yields with record low spreads to U.S. Treasuries.

In the U.S. there are many types of owners of power plants. Owners can be divided into:

1. *Investor-Owned Utilities*
2. *Cooperatives*
3. *Municipal Utilities*
4. *Independent Power Producers*
5. *Federal Utilities*
6. *Industrials*

Investor-Owned Utilities (IOU)
There are over 180 IOUs in the United States and thousands worldwide. They operate in every state except Nebraska, and each is regulated by state public utility commissions in state-assigned franchise areas. Typically, a state utilities commission provides an IOU with an exclusive service territory to provide electricity, water, and/or natural gas. As to electricity, IOU's have an "obligation to serve" every load in the service territory. This generally includes distribution and transmission and often, but not always, generation. Their national association is the Edison Electric Institute (EEI). In comparison to government-sponsored power providers, privately-owned utilities are financed by the contributions of their shareholders, as well as by funds borrowed on the open market at competitive rates.

Cooperatives
There are over 900 co-ops in North America, serving 42 million people. Most serve rural communities with a relatively small number of customers. Only a small number of co-ops own generation plants. They supply electricity to transmission- & distribution- (T&D) only co-ops. They are challenged by low electric usage across a broad area. They benefit from tax-free financing and a strong national network, the National Rural Electric Cooperative Association (NRECA).

Municipal Utilities
There are more than 2,000 community-owned utilities, serving 45 million people in the United States. Some, such as the Los Angeles Department of Water and Power, serve millions of customers, while others are modest in size. The American Public Power Association (APPA) is the main association for these utilities.

Independent Power Producer (IPP)
Sometimes called a Non-utility Generator (NUG), an IPP is a power plant that is not owned by a regulated public utility. There are over 1,700 IPP projects in the US. IPPs have built a majority of new power generation facilities in the past decade, including coal plants, natural gas fired peaking plants and combined cycle plants, and renewable energy source facilities such as hydro power, solar, wind and other alternative energy projects.

'FACTORS' IN OVERVALUATION

In addition to the aforementioned considerations, modern portfolio theory appears to have influenced the valuation of electric utilities. This is because the orchestrators of indexes, as well as a number of pension consultants and asset allocators, have come to the conclusion that superior performance is the result of a portfolio manager's emphasis on certain factors. For example, MSCI[3] issued a paper in December 2013, entitled "The Foundations of Factor Investing," that identified six factors: value, low size (meaning small market capitalization), low volatility, high yield, quality, and momentum. The original Fama-French model[4] identified three factors (market beta, size, and value). Utilities fall into both the yield and low-volatility segments because they have not been volatile historically. In addition, they

[3] MSCI is a leading provider of investment decision support tools to over 6,000 clients worldwide, ranging from large pension plans to boutique hedge funds.
[4] In asset pricing and portfolio management, the Fama–French three-factor model is a model designed by Eugene Fama and Kenneth French to describe stock returns.

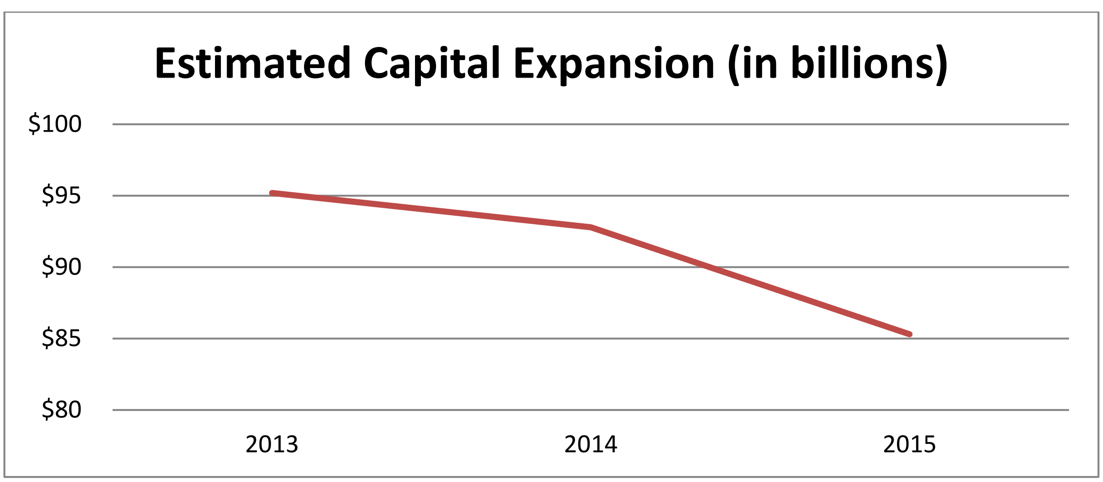
also fall into the quality segment if their ROE is sufficiently elevated and adequately stable; utilities, therefore, can be found to have three of the six factors.

As a result of this reasoning, the utilities sector has become a favored allocation for investors seeking yield and safety. With the present 3.0% yield for the average electric utility company, vis-à-vis 2.2% for a 10-year Treasury Note, there is not much in terms of a risk premium currently reflected in these utility valuations. Consequently, investors appear to believe that an investment in electric utilities is almost as safe as an investment in Treasuries. Alternatively, investors might expect dividends from these utilities to rise meaningfully over time. However, based on the findings in this paper, it appears that utilities are not the safe investment generally believed and that the probability of future dividend increases might be greatly overestimated.

SLOWDOWN IN CAPITAL EXPENDITURES

Utilities currently enjoy a very low cost of capital. Using the inverse of the trailing P/E multiple indicates a 4.7% cost of equity capital and, based on the iShares Utilities Bond ETF (AMPS), the bond yields average just less than 3% (it is noteworthy that AMPS has returned approximately 11% year-to-date). Of course, under these circumstances, and given the fact that regulated utilities are usually allowed to generate a guaranteed ROE of approximately 10%, they clearly have an incentive to deploy as much capital as possible and earn the spread. However, given the present trends in the electric utility industry, it is questionable whether a new power plant constructed today will still be in use in 30 to 60 years, which is the time period used by most utilities to fully depreciate these assets. With declining demand for energy, it is also less likely that regulators will allow electric utilities to deploy more capital to build new power plants to replace older ones.

In fact, capital expansion already appears to be slowing, following a period of growth enabled in part by stimulus funding for smart-grid upgrades. Based on September 2013 projections by EEI, the lobbying group supported by investor-owned utilities, capital expansion is projected to decline in 2014 to $92.8 billion, from last year's estimated $95.2 billion, and decline further to $85.3 billion in 2015. This is important, since utilities are compensated based on the value of their capital expenditures:



Source: EEI

This declining trend is perhaps a reflection of the fact that utilities are currently placing more emphasis on upgrading their transmission grids, as opposed to building power plants. For example, New Jersey-based utility Public Service Enterprise Group Inc. (PSE&G) recently announced that it plans to spend $10 billion over the next five years to upgrade its grid. This represents a 40% increase compared to the company's projections just one year earlier. It also plans to invest $2.6 billion over the next five years "to make its gas and electric systems more resilient to extreme weather," but expects to spend an insignificant amount on additional power projects.

This switch in strategy, from investing in power plants to investing in upgrade-related areas, is partly done to lower risks by reducing dependence on capacity utilization in unregulated power plants, but also because transmission projects are largely decided by FERC, which typically grants the utility a higher ROE on their investment than would state regulators. For the nearly $3 billion of transmission projects currently underway, the return varies from 11.6% to 12.9%. Given that PSE&G has an annual depreciation allowance of approximately $1.4 billion, the proposed plan, if approved, would keep its asset base from shrinking over the next five years, but with $22.3 billion in Property, Plant, and Equipment (PP&E) on its balance sheet as of June 30, 2014, that figure might increase by perhaps $3 to 4 billion, after accounting for escalating depreciation expenses. Thus, a $4 billion net increase in PP&E would represent just a 17.9% cumulative expansion over the five-year period, compared to the 50% increase in the prior five-year period, since June 30, 2009, when the company had $14.9 billion in PP&E. In addition, once these grid upgrades have been made, and assuming demand for electricity continues to be muted, which areas can PSE&G target for capital expenditures in the following five-year period?

INTEREST RATES: A LOSE-LOSE PAYOFF SCHEDULE

Interest rates have declined steadily, more or less, for more than 30 years. The interest rate on the 10-year Treasury Bond reached 15.32% in September 1981, compared to 2.20% as of this writing. Hence, given the added boost that utilities have received from declining interest rates, as manifested in a declining cost of debt, a repeat of the past 33 years is effectively impossible. It is, actually, theoretically possible, but would require that investors would be willing to pay the Federal Government 10.64% per annum in order to own 10-year Treasuries (which would be required to provide a similar boost over the next 33 years as has occurred in the prior period). Instead, if interest rates and inflation remain at their present levels, the allowed return on capital (as determined in periodic rate cases) will continue to follow the downward trend of utilities' cost of capital. In 2000, the average utility corporate bond coupon rate was approximately 8%, and the average allowed ROE was 11.6%. In 2010, the corresponding figures were 5% and 10.4%. In 2013: 3.5% and 10.0%[5]. Thus, the gap between the ROE and the cost of capital has widened from 3.6% in 2000, to 6.5% in 2013, which has resulted in better-than-average earnings growth for the utilities. However, a declining ROE (assuming no increase in interest rates), coupled with reduced or no expansion of the regulated asset base, would prohibit an increase in future earnings and dividends, which is the historic norm that is built into the share valuations.

[5] Sources: Regulatory decisions and documents; annual information forms; annual reports.

Alternatively, if interest rates were to increase from the current, historically low levels, which appears more probable than a continued decline, the cost of capital for electric utilities would probably increase as well. Also, the cost of equity is the return that stockholders require for their investment in a company, so this cost of capital would increase as well if stock prices were to decline. Of course, utilities' cost of capital might increase even if the yield on Treasuries remains constant, should the spread between Treasuries and electric utility bonds widen. In either case, a higher cost of capital for the utilities would add to the cost of power generation. Even if the regulators allow electric utilities to pass these interest expenses on to consumers, this would be a long process, measured over the course of years; whereas, the decline in share price valuation would occur immediately, and it would, ultimately, only increase the cost of electricity in relation to the competition from solar power, which is becoming cheaper every year. Thus, the rise in interest rates, were it actually to take place, would only speed up the disruption from electric to solar. More likely, regulators may convince electric utilities to retain older (fully depreciated) power plants rather than replacing them with new ones, in order to keep costs down for consumers. While this may make utilities' price points lower, and more competitive with solar, the question becomes one of how the regulators would compensate utilities for this phenomenon. Profit margins could suffer as a result.

A Demand Threat – Increased Energy Efficiency

The current economic recovery is making itself known in a variety of ways, including increases in construction starts and consumer spending. However, one key indicator of a growing economy—rising electricity demand—is notably absent. While the U.S. gross domestic product (GDP) has expanded during the last six years, electricity demand has actually contracted—a heretofore unknown occurrence in the history of the U.S. Electricity demand was 3,892 billion KW in 2008, but has declined 2.5% since then, even though GDP has expanded by 5.5% in real terms and 13.9% on a nominal basis, which is probably a better comparison:

(In billion KW)	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
United States	3,365	3,450	3,613	3,479	3,602	3,660	3,656	3,717	3,892	3,892	3,873	3,873	3,741	3,793

Source EIA

The reason for this phenomenon is partly due to improvements in energy-efficiency, including appliances, as well as changes in construction codes and other regulations. In addition, many electrical utility companies have for years encouraged their users to buy energy-efficient products. Some even offer rebates or incentives for customers who choose to do an upgrade or retrofit. Therefore, electrical utilities have been working to downsize their operations, encouraging their own customers to use less of their product. This seems a bit counter-intuitive by any marketing standard. One could even go so far as to say that the energy-efficiency industry is a competitor for utilities whose share prices and dividends depend on selling more kilowatt-hours every year.

In its 2014 Annual Energy Outlook, the U.S. Energy Information Administration (EIA) states that electricity demand will increase no more than 0.9 percent per year between 2014 and 2040. This follows four of the past five years in which electricity usage actually declined. Growth of electricity demand (including retail sales and direct use) has slowed in each decade since the 1950s, from 9.8% per year from 1949 to 1959, to only 0.7% per year since 2000. Consequently, the projected 0.9% long-term growth rate could be considered optimistic, particularly in light of the recent changes in the industry outlined in this paper. By comparison, according to the International Energy Agency, total energy demand in Europe will decline by 2% between 2010 and 2015; thus, these trends are affecting all major economies. According to analysis from UBS[6], demand for electricity in Australia has dropped by 13% over the past four years, and it is estimated that 75% of Australia's residential buildings, and up to 90% of commercial buildings may be equipped with rooftop solar panels within 10 years.

To understand the very real, cumulative effect that individual efficiency improvements can have upon aggregate power demand, consider lighting. The regulations covering lamp efficiency just took effect for 60-watt-equivalent lamps (producing approximately 800 lumens of illumination) on January 1, 2014. As existing 60W incandescent lamps burn out, they can be replaced by 13W compact fluorescent or 8 or 9W LEDs. Similarly, refrigerators—which consumed, on average, 1,800 kWh per year in 1978—currently require less than 400 kWh, according to a 2014 Department of Energy standard. Furthermore, "smart grids", which tell consumers how much power they are using, shut off appliances when not needed and manage demand more efficiently, will exacerbate these trends.

When these energy efficiency improvements are multiplied by scores of millions of households across the country—along with equally large numbers of businesses upgrading their lighting and mechanical systems—it will have a significant impact on the historical upward path of energy consumption in the United States. It also, for the first time, decouples electricity demand from economic growth. However, reliable demand growth has been a primary fundamental factor in the stock market valuation of electric utility companies. Thus, this structural change in industry economics in and of itself should be raising concern among utility investors.

Again, regulated utilities are guaranteed a rate of return, based on their capital investments in everything from meters to substations and transmission lines, and utility customers pay that rate of return in the kilowatt-hour charges that are enumerated in their monthly bills. In the short term, customers might experience increasing rates because of this arrangement, as that guaranteed return is spread over a decreasing number of kilowatt-hours sold. However, as utilities make their rate case request before their state public utility commissions, they could experience resistance to further expansion plans if regulators do not see a market need. Under these circumstances, what are utilities likely to do? Perhaps undertake one of the following actions:

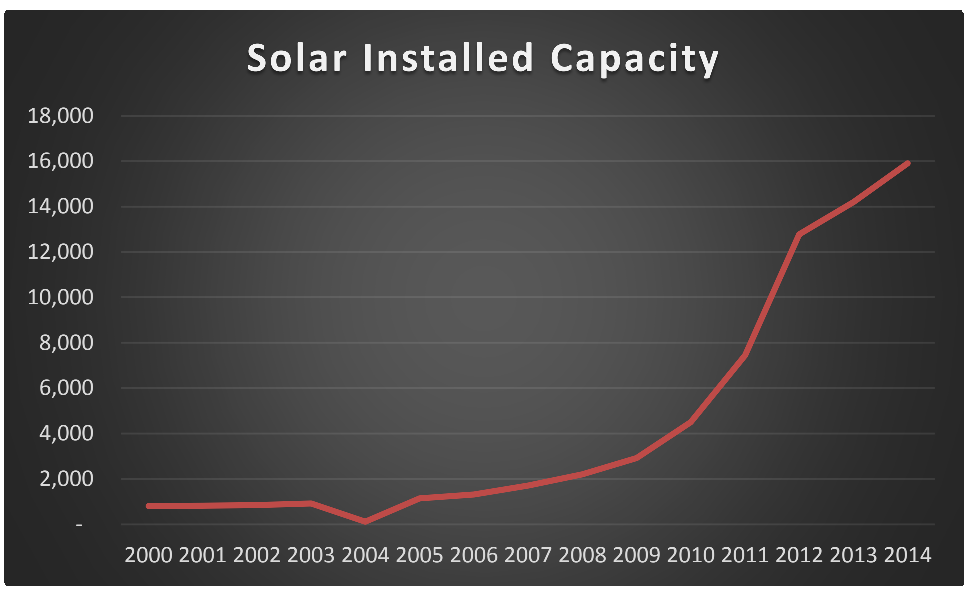
- Accept reduced profits,
- Be forced to reduce expansion and upgrades, while retaining their profitability,
- Raise electricity rates, or
- Re-examine their business model

[6]Source: http://bgr.com/2014/07/09/solar-vs-coal-power/

Approximately half of the states have regulated energy markets. In those states, utility companies are guaranteed a rate of return and are more likely to pass higher costs on to consumers. Consequently, in states where the electricity market is deregulated—where utilities are basically electricity resellers, purchasing power from merchant generators and selling it to their customers, there are no guaranteed rates of return, and if demand for energy were to decline sufficiently, these utilities would become unprofitable.

A LARGER DEMAND THREAT – DISRUPTION FROM SOLAR POWER

For more than a decade, there has been a huge push from governments around the world to subsidize renewable energy sources such as solar power. As a result, the utility market is presently in the early stages of being disrupted by the rapid increase in the generation of solar power and, to a lesser extent (at least in the U.S.), wind power. Installed solar capacity, mainly in the form of roof-top PV power generation, has increased at a compound annual growth rate of 60% since 2008 and prices in the U.S. have declined significantly—down 15% in 2013 alone to $2.59 per watt, which is a 60% decline since the beginning of 2011. This rapid decline is partly a result of competition from Chinese solar-cell manufacturers, which produced 63% of all solar-panels worldwide in 2011 (and 31% of all the modules installed in the U.S. in 2013[7]). Chinese companies, in general, ramped up production earlier than U.S.-based manufacturers and reached economies of scale earlier, which gave them a pricing advantage. Of course, some observers accuse China's government of providing these companies with certain advantages and, hence, the import of Chinese solar cells is now subject to various tariffs. Even so, this worldwide competition for supremacy in the solar-cell manufacturing industry has led to rapid reduction in pricing, which is partly the result of improved efficiency. As a result, installed capacity in the U.S. has expanded 10-fold since 2008:



In MW. 2014 represents the June 30, 2014 estimate. Source: NREL, U.S. Solar Market Insight

[7] http://www.greentechmedia.com/articles/read/New-Tariffs-on-Chinese-Solar-Modules-Will-Raise-US-Price-by-14

According to solar panel installation company SunRun, the typical home installation capacity ranges from 3-7KW, sufficient to generate 15-50KWh per day, depending on location, as compared to the average consumer's daily consumption of approximately 30KWh[8]. PVs cost between $18,000 and $40,000 to have installed, before a 30% federal investment tax credit, as well as state and local rebates. Historically, this has placed solar panel solutions out of reach for most households; however, there are now lease programs available that offer solar panels with no out-of-pocket expenditures for some customers. Instead, the installation company charges consumers a fixed monthly fee, which to a large extent locks in the price of electricity for the consumer (although not fully, since the conventional electric power grid is often used as backup or when the sun does not shine, unless the consumer also has a large capacity battery). When a solar panel company offers customers an installation for no money down, which reduces the electric bill to zero (or near zero), and has the consumer pay a lease agreement that is less than the equivalent electric utility bill, it clearly sends a persuasive marketing message to most consumers. A further inducement is that the arrangement might shield these customers from potential increases in electricity prices that may well ultimately result, as utilities attempt to recover their capital investments from a shrinking customer base that is using less energy.

In a recent development, homebuilders in master planned communities, such as Lennar (the nation's second-largest homebuilder), now include PV roof installations automatically, without the prior request of the buyer, at approximately 100 Lennar subdivisions in California. That appears to be an impressive indication of the degree of commercial acceptance of this technology—that solar panel technology is no longer just for the 'early adopter,' but is becoming mainstream. Lennar recently decided to expand this policy to several more states, starting with Colorado. The company typically retains ownership of the panels and signs 20-year deals to sell homeowners the power from their own roofs, at a 20 percent discount from the local utility's prices. Should this policy be adopted by all homebuilders nationwide, millions of new homes could be equipped with solar panels over the next few years. Furthermore, this trend appears to be global: in Japan, homes with wholly self-sufficient solar and storage systems account for 60% of all orders from leading home builder Sekisui House.

The power generated by solar panels on residential or commercial roofs is not utility-owned or utility-purchased. Accordingly, from the utility's point of view, every kilowatt-hour of rooftop solar power can be considered a kilowatt-hour of reduced demand for its product. Solar power peaks at midday, which means it is at its strongest close to the point at which electricity demand is at its highest—"peak load." This is a double-pronged problem, because providing power to meet peak load is the most expensive and, for the utility, most profitable power. Consequently, when solar panels provide peak power, they are not just displacing demand for utility power, they are reducing demand for the utilities' highest-margin revenue stream.

In the fourth quarter of 2013 alone, 2,106 MW of solar power was added, a 60% expansion over the same period in the prior year, indicating that the 5-year average growth rate of solar power installations has been sustained. In fact, solar accounted for 29 percent of all new electricity generation capacity added in 2013, an increase from just 10 percent in 2012,

[8] According to the U.S. Energy Information Administration, as of 2012.

making it the second largest source of new electricity generating capacity, behind natural gas. At this rate, by the end of 2014, solar capacity could exceed 20GW, which is enough to power 3.4 million average American homes, according to the Solar Energy Industry Association. Given that there are 115 million U.S. households, this represents a market share just below 3%; therefore, it only impacts electric utilities on the margin at the current time, particularly since the residential power market only represents slightly less than half of the total electricity demand, with industrial and other commercial demand accounting for the difference.

However, should expansion on this order continue for another few years, solar power could easily reach a 10% household penetration in the not-too-distant future. Industry analysts estimate that the cost of solar, plus a storage solution, for residential consumers of electricity is already competitive with the price of utility grid power in the state of Hawaii, where one in ten homes on the most populous island, Oahu, currently has solar panels on its roof. Hawaii's 358 MW of installed solar PV in 2013 represented 12.9% of peak electric capacity, according to Clean Edge's 2014 Index[9]. This is the highest proportion of any U.S. state. At current trend rates, it appears other states, such as California, New York, and Arizona, among others, are just a few years behind Hawaii.

For example, California, the second most expensive state for residential electricity, is expected to reach price equilibrium by 2017, with New York and Arizona following a year later. According to a study by the Institute for Local Self-Reliance, by 2021, rooftop solar power will be as cheap as, or cheaper than, electricity from local utilities for half the U.S. population.

Another research company, Bloomberg Energy Finance, forecasts 22 percent compound annual growth in all solar PV, which indicates that by 2020 distributed solar (which will account for about 15 percent of total PV) could reach up to 10 percent of load (what the utility is providing) in certain areas. Assuming a decline in load, and possibly customers served, of 10 percent due to DER (distributed energy resources, which for the most part refers to solar PV), with full subsidization of DER participants, the average impact on base electricity prices for customers not using solar power will be perhaps a 20 percent increase in rates. This would include the effect of customers leaving the grid, thus both reducing demand and, by also selling power back to the utility, increasing supply, typically during periods of peak power demand.

Elon Musk-backed Solar City has plans to significantly increase its annual production to the point at which it would produce module capacity of 10GW or more each year. If the company reaches that goal, Solar City alone (not counting its many competitors) would capture an additional 1% of the total residential power consumption every year, removing that demand from the utilities (and perhaps returning electricity to the grid through net-metering). This would mean lower capacity utilization for the traditional electric utilities that do not utilize solar, since coal, natural gas, and nuclear power plants will have to operate much below full capacity in a declining-demand market.

[9] Clean Edge indexes, leveraging extensive data analytics and key benchmarking methodologies, cover key clean-energy market activity for diverse stakeholders including corporations, government agencies, economic development agencies, NGOs, service firms, and investors.

If this were to transpire, it would create an over-supply problem not unlike that which arose when the United States discovered tremendous quantities of natural gas, and from which natural gas pricing has yet to recover. Prior to that, an historical spread between oil and natural gas prices had existed for decades, but was disrupted by those new supplies. A similar development in the electric utility market is not far-fetched. Consequently, this could be a disruptive, seminal change for the utility industry, potentially resulting in a lack of growth for the foreseeable future, or even substantial declines in profitability in the deregulated side of the business. One might presume that most of the plants that will be retired in the coming decade will not be replaced, simply because the capacity will not be needed. If so, the rate base for utilities will continue to decline for the foreseeable future, which would not bode well for future earnings generation and dividends.

Utility investors are accustomed to large, long-term, reliable investments with a 30-50 year cost recovery—fossil fuel plants, basically. The cost of those investments, along with investments in grid maintenance and reliability, are spread by utilities across all ratepayers in a service area. It is not entirely clear what will happen if some ratepayers begin to reduce their demand or opt out of the grid entirely. The investment base will be the same, but its cost of maintenance will have to be borne by an increasingly smaller group of ratepayers. Consequently, those customers who have not switched to solar will experience higher rates. According to EEI:

> "Due to the variable nature of renewable DER, there is a perception that customers will always need to remain on the grid. While we would expect customers to remain on the grid until a fully viable and economic distributed non-variable resource is available, *one can imagine a day when battery storage technology or micro turbines could allow customers to be electric grid independent.* To put this into perspective, who would have believed 10 years ago that traditional wire line telephone customers could economically "cut the cord?" [Our emphasis]

In addition, Duke Energy CEO Jim Rogers recently stated "If the cost of solar panels keeps coming down, installation costs come down and if they combine solar with battery technology and a power management system, then we have someone just using [the grid] for backup[10]." In that case, the question becomes, what happens if a meaningful percentage of customers start generating their own power and using the grid merely as backup? The EEI report warns of "irreparable damages to revenues and growth prospects" of utilities.

Residential power accounts for just less than half of U.S. electric utilities' business. However, that does not mean that the industrial/commercial side of energy consumption will necessarily remain steady. For example, Walmart recently expressed interest in solar and particularly in Bloom Energy - a company that is producing an energy 'box' that can use a wide variety of inputs (including liquid or gaseous hydrocarbons produced from biological sources to generate electricity on the site where it will be used). This is significant since Walmart is the second largest consumer of electricity in the U.S. and is already using more solar power than any other corporation in the U.S. Also, Apple recently announced plans to expand its massive North Carolina solar power farm substantially.

[10] http://www.solarexchange.com/blog/?cat=4&paged=3

STORAGE – THE REAL DISRUPTOR?

Homeowners with solar panels on their roofs have experienced what is known as the intermittency problem–e.g., the sun does not always shine. Consequently, to keep their lights on at night, they had to make a deal with their utility company: they will continue to purchase electric power from the utility, but they will keep their solar panels running at times when they are not at home and sell any excess power generated back onto the grid. This is called net metering. While net metering has been a boon for incentivizing rooftop solar adoption, the repercussions are not fully known. For example, what will the utility company do when increasing numbers of consumers try to sell back their roof-top-generated solar power to the utility, which by then will likely be experience declining utilization rates?

Rooftop solar panels are becoming such a powerful factor in the energy market that they now can push the price of electricity to negative territory in the sunniest regions of the world. This is possible because powering down fossil fuel energy generators during peak solar power periods would be more expensive than paying customers to use the electricity. The following examples indicate that peaking plants may already be on their way to obsolescence in other parts in the world.

- According to the Economist "On June 16th [2013] something very peculiar happened in Germany's electricity market. The wholesale price of electricity fell to minus €100 per megawatt hour (MWh). That is, generating companies were having to pay the managers of the grid to take their electricity. It was a bright, breezy Sunday. Demand was low. Between 2pm and 3pm, solar and wind generators produced 28.9 gigawatts (GW) of power, more than half the total. The grid at that time could not cope with more than 45GW without becoming unstable. At the peak, total generation was over 51GW; so prices went negative to encourage cutbacks and protect the grid from overloading. The trouble is that power plants using nuclear fuel or brown coal are designed to run full blast and cannot easily reduce production, whereas the extra energy from solar and wind power is free. So the burden of adjustment fell on gas-fired and hard-coal power plants, whose output plummeted to only about 10% of capacity."[11]

- Similarly, the negative energy price barrier was breached in Queensland, Australia, where low demand and high rooftop solar power generation pushed the wholesale electricity price to AUD -$100 per megawatt-hour on Wednesday afternoon, July 2, 2014. These events could be considered a microcosm of the changes affecting all places where renewable sources of energy are becoming more important.

However, if utilities end up selling less electricity to fewer customers, the result should be a price increase for the remaining customers, and probably a surcharge for those who rely on the grid "only in emergency," to maintain the lines and make sure the customer can both buy and receive electricity in an emergency. Thus, as long as consumers are connected to the grid, even via net metering, they are still in a position in which the utility company can charge them an unknown amount for access to the grid during off-solar hours.

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[11] http://www.economist.com/news/briefing/21587782-europes-electricity-providers-face-existential-threat-how-lose-half-trillion-euros.

The solution to this dilemma is a solar-charged battery, which can store power for use when the sun is not shining. Ultimately, this would allow consumers to completely disconnect from the grid. As recently as 2009, the all-in costs for such batteries would have been as much as $17,000 for a moderate storage capacity unit. However, with the expansion of electric vehicle production, according to Barclays[12], the cost of storage has been falling rapidly and now stands at about $3,700. Battery costs may decline to a considerably greater extent if Elon Musk is successful with his plans to open a "Gigafactory"—a proposed lithium ion battery factory of Tesla Motors slated to be operational by 2020. Once these solar batteries are widely available for consumers (they are currently only available in California to Solar City customers), a complete disconnect from the grid becomes technologically feasible.

The combined effect of solar cells, batteries, and electric cars represents somewhat of a virtuous cycle as advances in battery technology. Efforts to increase the scale of battery production could reduce battery costs, which in turn would make electric vehicles and stationary battery storage for homes cheaper, increasing demand for both. Then, expansion of the electric car market may drive further improvements in battery technology, and the virtuous cycle will continue. Consequently, scientific leaps in the battery industry underscore the fundamental change in the consumption and production of energy.

As solar panel efficiency continues to improve, while prices of such installations decline, and as the availability of affordable storage solutions emerge, the result could be a feedback loop in which early adopters begin leaving the grid, incrementally increasing regulated utilities' power costs. However, since regulated utilities are guaranteed a specific rate of return, they will probably be able to raise prices to reach their profitability targets, which would further exacerbate the shift into solar and storage since it would then become comparatively more attractive, causing the pattern to repeat itself. While regulated utilities may be able to raise prices to consumers and retain their profit margins in the near term, unregulated merchant power generators will not be able to raise prices to offset declining demand. More likely, their prices would decrease as demand diminishes.

THE EUROPEAN EXPERIENCE

In Europe, Germany has the most developed solar panel market. According to government development agency Germany Trade and Invest (GTAI), solar power expanded 34% in the first five months of 2014 compared to last year and has a total of approximately 1.4 million installed PV systems. In fact, on June 9th of this year, in total, solar power generated a peak of 23.1GW hours at lunchtime, equivalent to 50.6% of Germany's total electricity need. This was the first time more than half of the country's energy needs had been met with solar power. Of course, the result of this trend has not been favorable to German electric utilities, which are some of the largest in Europe. For example, the share price of E.ON (Europe's largest electric utility by revenues) declined by 54.4% from January 1, 2010 to October 30, 2014, which represented a 15.0% annualized loss (excluding dividends). Germany's second

[12] http://www.businessinsider.com/barclays-downgrades-utilities-on-solar-threat-2014-5

largest electric utility, RWE, declined by 59.1% over the same time period, or 16.9% annualized. By comparison, the German stock market, as measured by the DAX[13], was up by 55.3% during the same time period.

Similar examples can be found in France, Italy, and many other European countries. GDF Suez, which is the largest French electric utility (and has substantial operations in the U.K. as well), achieved an annualized return of 1.3% over the aforementioned time period, while the second largest utility, Électricité de France (EDF) suffered an 11.6% annualized loss. Italy's Enel, which is Europe's third largest utility, declined by 0.7% annualized over the same approximately 5-year time period. These five companies were, and remain, the five largest utilities in Europe by revenue, and the average share price loss was 25% during this period. This could very well be a precursor of future developments in the United States electric utility sector, given that Europe appears to be several years ahead in terms of the solar energy build-out and promotion.

Eni SpA, Italy's second largest utility, has declined by 20%, or 4.5% annualized since January 1, 2010 while Britain's Centrica, which is much more diversified, with operations in Canada and the US, has gained 36%, or 6.5% annualized. The Dow Jones Utility Average, by comparison, has gained 53% over that time period, or 9.2% annualized (excluding dividends), and the ETFs have performed even better:

Company/ETF	Country	Total Performance*	Annualized Performance
E.ON	Germany	-35.8%	-8.7%
RWE	Germany	-43.7%	-11.2%
GDF Suez	France	-9.1%	-2.0%
EDF (Électricité de France)	France	-27.2%	-6.4%
Enel	Italy	35.4%	6.5%
Eni	Italy	31.1%	5.8%
Centrica	U.K	39.5%	7.1%
National Grid	U.K	106.7%	16.2%
Vanguard Utilities ETF (VPU)	US	81.4%	13.1%
iShares US Utilities (IDU)	US	80.1%	12.9%

Source: Bloomberg. Assumes dividend reinvested. * performance from 1/1/2010-10/31/2014

It should be noted that there is a significant discrepancy between the first two groups of companies. This could be explained by the fact that Germany generates the most solar power in the world, with an estimated 35.5GW[14] of capacity. France has the 7th largest installed base in the world, with 4.6GW, while the U.K. has 2.9GW of solar installations (most of which has been installed in the last two years). Consequently, it is possible that the German experience has yet to transpire in other European countries. The positive return experience of the Italian utilities, despite Italy's having the third-largest installed PV capacity, at 17.6GW, might be well explained by the fact that they're vastly more diversified. Eni, for

[13] The DAX (Deutscher Aktienindex) is stock index that represents 30 of the largest and most liquid German companies that trade on the Frankfurt Exchange.

[14] Source: Pureenergies.com/us/blog/top-10-countries-using-solar-power/.

example, has operations (including oil and gas exploration) in 79 countries, while Enel operates in 40 countries including the U.S., Canada, and some Latin American countries. Therefore, the globally diversified European utilities might be inadequate proxies for any systemic risk in the Italian electric utility market. Even so, the American ETFs have achieved approximately double the performance of these Italian utilities, at 13% annualized over the past (almost) five years.

GRAPHENE

Use as Solar Panel

Technological progress continues and no one can accurately forecast what the electric utility market will look like in 50 years, although many of the depreciation plans implemented by today's utilities indicate that they expect their power plants to continue to earn a return well past that point. One potential disruptor that could affect utilities within the next decade is graphene. In 2013, Michigan Technological University found that graphene could power solar cells by replacing platinum, which is a key ingredient in solar cells, but a highly expensive one at $1,420 an ounce. Because of its molecular structure, graphene has the conductivity and catalytic activity required to harness and convert the energy of the sun without losing any efficiency of its own. Since graphene is basically a single atomic layer of graphite, an abundant mineral, solar cells based on this material could be considerably thinner and therefore, easier to install. Of course, at its current price of $20,000 per ounce[15], it would have to be considerably thinner than the current platinum solution to become viable. However, as graphene enters mass production, the price will likely decline significantly over the next decade.

Graphene has also been shown to be a pretty incredible capacitor material (i.e., useful as an electric battery). Each layer of graphene is only 1 atom thick, allowing for a massive number of layers to be placed on top of each other. Also, it is virtually invisible and weighs practically nothing, making it a perfect fit for organic solar cells (which tend to be some of the cheapest solar cells, albeit less efficient compared to the more common single-junction solar cells). Despite its svelte form, graphene also possesses superior strength and unique conductive properties that make it ideal for electronic devices, including PV cells. Therefore, it may even be possible to create a transparent film using graphene-based solar cells, which could be used not only on rooftops but wrapped around houses and office buildings, potentially making even the buildings themselves energy self-sufficient.

Use as Storage

In the past, the basic unit of electrical capacitance (the ability of a body to store an electric charge), called "farad", was too large to be practical. In the electrical engineering field, microfarad (one millionth of farad), picofarad (one billionth of farad), and nanofarad (one million millionth of farad) were used to quantify capacitors. However, as a result of the recent progress of manufacturing technology, capacitors as large as a farad or more are now possible to construct. Graphene would make possible the manufacturing of multi-farad capacitors, which could basically replace the functionality of rechargeable batteries. In the not so distant future, a graphene super-capacitor could replace a small gas engine, powering

[15] Source: Paris Tech Review

an emergency generator with no noise, smoke, or carbon dioxide emission. Of course, the timing of the commercialization of graphene is widely debated, but its potential still provides an example of how future technologies can, and likely will, improve energy generation and storage in the not-too distant future.

'ALTERNATIVE' SPIN OFFS – POTENTIALLY CHANGING THE MARKET

One wholesale power company, NRG Energy Inc., has been worried about the looming competitive threat of alternative energy, and rightly so. In response, it created a very interesting security called NRG Yield Shares ("Yield Shares"). NRG took newly created so-called "clean energy production assets" and used them to back the Yield Shares. These plants include the 250-megawatt California Valley Solar Ranch, which was purchased from SunPower, the 392 MW Ivanpah solar thermal plant, and the 290 MW Agua Caliente Solar Project in Arizona (which it co-owns with MidAmerican Energy).

Such clean energy production assets are very different from coal-fired plants or nuclear plants in that they require very little maintenance capital expenditures for many years. Ultimately, they will require capital expenditures, but in the short run those needs are minimal. The company now collects tax credits from the U.S. Government (according to Section 1603 of the American Recovery and Reinvestment Tax Act of 2009, which pays cash to "reimburse eligible applicants for a portion of the cost of installing specified energy property used in a trade or business or for the production of income") and pays out 90% of the earnings from clean energy production assets to shareholders of the Yield Shares. This share class has managed to get to a valuation of 28x the current year's consensus earnings and yields 2.6%. NRG's long-term energy contracts have escalating sale prices, usually tied to some estimate of the future rate of inflation. The new Yield Shares show very consistent dividend growth, unlike conventional utilities, which are experiencing challenges to their earnings growth. Furthermore, the United States Government will pay NRG cash in lieu of investment tax credits, which the company can then pay out to shareholders.

To maintain the tax shield and to increase investor returns, a "Yieldco" company like NRG's Yield Shares vehicle needs to constantly add new assets with tax credits and depreciation to its portfolio. Yieldcos also need new projects to replace revenue streams from atrophying or obsolete assets. Consequently, a key success factor for any Yieldco is its access to a steady pipeline of new projects available for purchase; thus, the construction of these plants will probably continue at an escalating pace. Other companies, such as NewEra Energy and SunEdison, are contemplating similar strategies. This is a really important phenomenon, because it will create a cleavage, or a divide, in the utility industry between companies that can take advantage of the tax credit cost of capital and those utilities that cannot. The issue here is not so much that the utility receives a tax credit that can be passed on to shareholders or placed in a separate company; rather, a utility can now create a separate currency that it can issue either to raise cash or to acquire additional assets. This is a new mechanism for growth since it provides an inexpensive cost of capital, should the utility make acquisitions or issue new shares in the Yield entity.

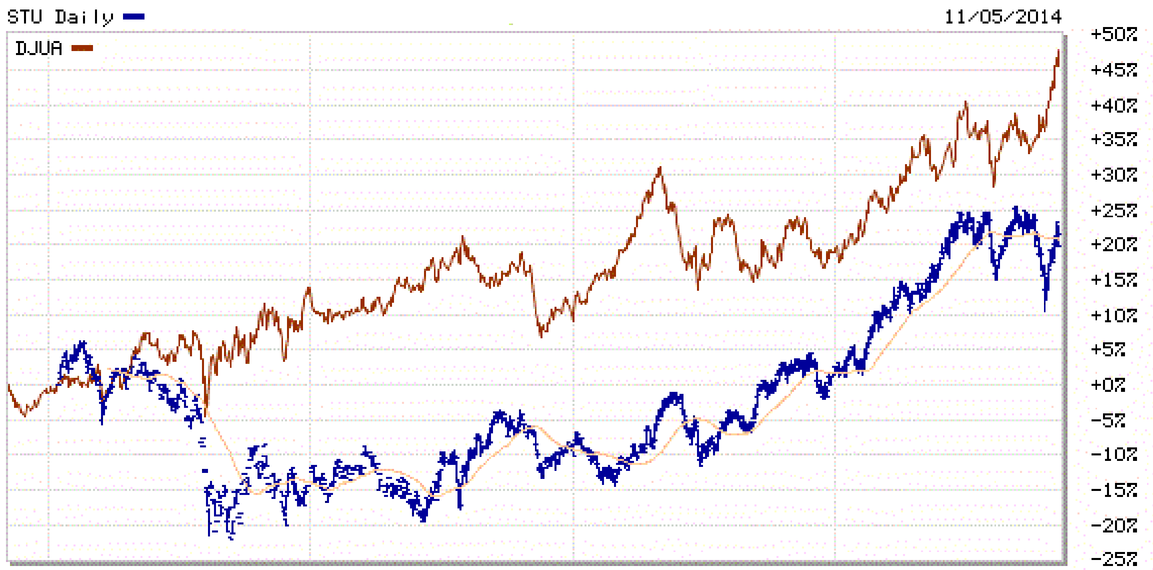
The second consequence is that those utilities that cannot take advantage of the tax credit cost of capital could be financially damaged by those that can. It is conceivable that unregulated energy generating assets in certain areas will eventually operate below their capacity utilization break-even rates and lose money as solar and wind generation expand. Again, electricity generation in many regions of the United States is now rate-of-return deregulated: if the utilization rate of the power plant falls below a certain level, it (which is to say its shareholders as well) will lose money, since the regulators (which is to say the utility customers as well) will not reimburse the utility. In other words, the utilities that can build solar plants as well as other renewable energy plants could achieve a lower cost of capital and, ultimately, be able to underprice the utilities that are not able to do this. Thus, to the extent that utilities themselves will add renewable energy plants (which is separate from consumers installing solar panels on their roofs), those that do so will probably be less impacted by declining energy prices than those that do not.

VALUATION

A multiple expansion scenario for the utility group appears increasingly unlikely, since the group is now trading at a premium valuation to the S&P 500® Index of 17x forward earnings, compared to 16x for the broader market. Over the past 20 years, the utility group has traded largely in line with the broader market, on average at 14x earnings; therefore, it is currently trading at a significant premium to the historic period despite weakened load growth prospects and an upcoming transition to slower rate base growth on average (based on EEI forecasts).

It may even be optimistic to believe electric utilities will be able to grow at all over a longer time period, such as the next decade, given the challenges the industry faces. In Europe, the solar panel trend was established earlier and has advanced to the point where the continent appears to be a few years ahead of the United States in the build out. Therefore, it is interesting to note that the decline of Europe's utilities has been dramatic. At their peak in 2008, the top 20 energy utilities were worth roughly €1 trillion ($1.3 trillion), whereas today, they are worth less than half that. In fact, since September 2008, utilities have been the worst-performing sector in the Morgan Stanley index of global share prices. Furthermore, in 2008 the top ten European utilities all had credit ratings of A or better. Now only five do. Of course, the main reason for this is competition from wind and solar, as well as net-metering, which allows customers to sell power back to the utilities at (from the utilities' point of view) the worst possible time, i.e., mid-day when energy usage and power prices are at their peak.

The chart below outlines the performance in the past four years for the SPDR MSCI Europe Utilities ETF (STU) compared to the Dow Jones Utility Index (DJUA):



It should be noted that the STU's largest position is in National Grid, a UK company mainly involved with energy distribution, whose shares have advanced 58% in the past four years. Even so, STU had advanced approximately 22% as of November 5th, 2014; whereas, the DJUA had advanced more than twice as much.

The Yield Premium Does Not Compensate For the Risks

The table below lists 10 of the largest U.S. electric utilities and their associated yields. The yields range from 2.5% for Edison International (California Edison) to 4.9% for Southern Company:

Ten Large Utilities

Company	Yield
Consolidated Edison Inc. (ED)	4.5%
Northern Utilities (NU)	3.6%
Edison International (EIX)	2.5%
Portland General Elect. Co. (POR)	3.5%
Sempra Energy (SRE)	2.7%
Southern Co. (SO)	4.9%
Duke Energy Corp. (DUK)	4.4%
Entergy Corp. (ETR)	4.6%
NextEra Energy, Inc. (NEE)	3.1%
American Electric Power Co., Inc. (AEP)	3.9%
Average:	***3.8%***

Source: Bloomberg, as of October 31, 2014

Incidentally, the average yield for this same group of companies was 4.0% two years ago, in October 2012, even though the yield on the 10-year Treasury Bond at the time was only 1.6%. Thus, the risk premium two years ago was 2.4% (4.0% minus 1.6%) while it is now just 1.4% (3.8% minus 2.4%). In addition, the Utility ETFs yield just around 3.0%, indicating a 60 basis points (bps) premium. The extra yield of 0.6% - 1.4% that utilities provide over

Treasuries, however, is attached with a number of issues, some of which might potentially be serious. For example, in July 2011, the Federal Environmental Protection Administration required additional reductions in sulfur dioxide and nitrous oxide emissions, under the Cross-State Air Pollution Rule that replaces the Clean Air Interstate Rule (CAIR). It affects 27 states. There are going to be necessary expenditures on the part of utilities. It is not entirely clear how much of it is going to be eligible for the rate base.

Similarly, in 2011, the Environmental Protection Agency (EPA) issued final Federal rules regarding what is known as the Maximum Achievable Control Technology (MACT) standards in utilities that burn fossil fuels—and virtually all utilities burn fossil fuels. Not only are the utilities regulated by states, but many Federal agencies have jurisdiction over them within their own spheres.

For example, two Federal agencies, the EPA and the Civil Aeronautics Administration, partnered to issue regulatory requirements regarding the creation of regional haze, because it can affect air traffic. One of these pollutants is nothing other than heat exhaust. If there is a certain amount of humidity in the atmosphere and a sufficient level of heat exhaust from the utility power stack, haze may be created. Of course, that is not the only emission of concern: control of greenhouse gases is also important to those agencies.

Another ruling by the EPA in April 2011 set standards for the acceptable mortality of aquatic organisms pinned against utility plants' cooling water intake structures. These standards were created under the provisions of the Clean Water Act. There are also new regulations regarding the disposal of coal ash.

Most importantly, regulators are imposing requirements upon utilities to reduce demand for power. That is a situation one does not see in any other industry. The regulators themselves actually impose upon the utility the requirement that they sell less, not more, of their product. The logic is that the public opposes the construction of new power plants no matter what their nature, no matter where they are located. It is politically unfeasible in most jurisdictions to build power plants because of public resistance. To avoid building power plants—and sometimes it is necessary—utilities are required to place programmable thermostats in homes, to encourage customers to improve what is known as the 'building envelope' (the sealing of the interior of the building from exterior forces), and to encourage the use of fluorescent bulbs to replace incandescent bulbs. Fluorescent bulbs are four times as energy efficient as incandescents. Legislation at the Federal level has also been enacted, in the form of the Energy Independence and Security Act of 2007, to gradually phase out the sale and production of incandescent bulbs over the next several years. One result is household and commercial demand in a number of jurisdictions is actually starting to decline. One could argue that 60 basis points in yield above Treasuries could be gained if one buys a utility ETF, and that is true. However, it is often forgotten that utility dividends can decline and not infrequently do so, an example of which would be in the 2001-2002 period in the wake of the Enron debacle.

Looking back further, below are the yields of all the publicly traded utilities in 1972:

1972 Average Yield for Selected Utilities

American Electric Power	6.1%	Montana Power	5.2%
Arizona Public Service	5.3%	New England Electric	6.3%
Atlanta Gaslight	5.9%	New England Gas & Electric	6.8%
Atlantic City Electric	6.3%	NY State Electric & Gas	6.7%
Baltimore Gas & Electric	6.2%	Niagara Mohawk Power	6.7%
Boston Edison	6.6%	Northeast Utilities	6.3%
Brooklyn Union Gas	6.9%	Northern Indiana Public Svce.	5.1%
Carolina Power & Light	5.2%	Northern States Power	6.2%
Central Hudson Gas & Electric	6.3%	Ohio Edison	6.7%
Central Illinois Public Svce.	6.6%	Oklahoma Gas & Electric	5.0%
Central Louisiana Energy	4.5%	Pacific Gas & Electric	5.7%
Central & Southwest??	4.5%	Pacific Lighting	6.8%
Cincinnati Gas & Electric	6.4%	Pacific Power & Light	6.1%
Cleveland Electric Illuminating	6.5%	Pennsylvania Power & Light	6.4%
Columbus & Southern Ohio Electric	6.6%	Philadelphia Electric	7.1%
Con Edison (Commonwealth)	6.1%	Portland General Electric	6.6%
Con Edison	7.0%	Potomac Electric	6.5%
Consumers Power	6.7%	Public Service of Colorado	5.3%
Dayton Power & Light	6.8%	Public Service of Indiana	5.5%
Delmarva Power & Light	6.4%	Public Svce. Electric & Gas NJ	6.7%
Detroit Edison	6.7%	Puget Sound Power & Light	6.1%
Duke Power	6.1%	Rochester Gas & Electric	5.2%
Duquesne Light	6.8%	San Diego Gas & Electric	5.6%
Florida Power Corp.	3.8%	South Carolina Electric & Gas	5.9%
Florida Power & Light	3.0%	Southern California Edison	5.7%
General Public Utilities	7.2%	Southern Company	6.3%
Gulf State Utilities	5.0%	Southwestern Public Service	6.0%
Hawaiian Electric	5.0%	Tampa Electric	3.8%
Houston Industries	2.7%	Texas Utilities	3.2%
Illinois Power	6.6%	Toledo Edison	6.3%
Iowa Illinois Gas & Electric	7.0%	Tucson Electric Power	5.2%
Kansas City Power & Light	6.5%	Union Electric	7.0%
Kansas Power & Light	5.3%	Utah Power & Light	5.8%
Kentucky Utilities	6.5%	Virginia Electric & Power	5.5%
Long Island Lighting	6.2%	Wisconsin Electric	6.5%
Louisville Gas & Electric	5.1%	Wisconsin Public Service	6.8%
Middle South Utilities	4.4%		

Source: Moody's

The average yield for these 73 utilities was 5.91%. As an aside, the 10-year Treasury yielded 6.21% on average in 1972, and the 20-year Treasury yielded 6.01%. The latter figure was actually lower; the yield curve was inverted.

The first observation to make as one goes through this list is the number of unrecognizable names. This can be quantified and it is a measure of the industry consolidation that has taken place. To the extent that takeover premiums were paid in order to accomplish the consolidations, it is reflected in the historical return of the utility sector. However, it is obvious by looking at the list that such a degree of consolidation is essentially non-replicable. One cannot include utilities as an income-generating class and use the historical rate of return to draw reasonable conclusions. Also, on a portfolio basis, because the utility industry is far more concentrated than it was one or two decades ago, there is less diversification of risk. Companies such as Boston Edison, Dayton Power & Light, Duquesne Light, Delmarva Power & Light, Long Island Lighting, Ohio Edison, Union Electric, and Utah Power & Light are now part of larger utilities.

In addition, utilities have to contend with nuclear decommissioning risks, which could result in significantly higher expenses for utilities with such plants if they become uneconomical and need to be shut earlier than expected (before they are fully amortized, which usually takes 30-60 years of operation).

The issue for consideration is how many utilities in a utility portfolio would need to have a problem for the 60 basis point yield advantage (of the ETFs) to be negated by a decline in market value of the utilities themselves. The answer is fairly obvious: not very many. Unlike a normal dividend portfolio in which there will always be the individual circumstances of dividend decline, it can be, and usually is, offset by dividend growth occurring in other companies in the portfolio. It is going to be very difficult for most utilities to grow their dividends over time in a robust manner.

At the moment, utilities are marketed as bond substitutes and as one of the safer areas of the equity market when, in fact, the current low yield and high price-earnings valuation make utilities one of the more dangerous of the equity sectors. It appears that nothing is being priced in for the obvious risks described heretofore. Historically, the absolute yield was much higher. These are the lowest yields in utilities in, sequentially, 15 years and half a century. This situation occurred twice before, during the 1999/2000 bubble and, before that, in the 1960s, and in both instances, the aftermath was not good for utility investors.

A Study of the DuPont Model[16]

There is a prevailing presumption that utility stocks are safe stocks, which in today's parlance means less volatile. However, variables such as volatility are not predictive of what will develop, though the statistics are used as if they are. They simply measure what has already happened, and this data can be further refined by a great variety of sophisticated statistical treatments to buttress the sense of predictive capability. Yet, there is no information in those figures as to what circumstances served to create that price history or, therefore, what might alter that pattern. This is one of the limitations and often misleading effects of time series analysis and volatility statistics without contextual analysis.

Here, then, is some contextual analysis, to take us away from the day-to-day price and volatility reporting to which we are all subjected. We will consider the Utilities Select Sector SPDR ETF (XLU), which is fairly concentrated in that the ten largest positions as of October represented 59.0% of the portfolio. This is what happens to all market capitalization weighted indexes over time. Consequently, there is considerable security-specific risk in this ETF.

Also, one may calculate a general case-expected return based upon the basic profitability of these companies. This makes use of a traditional formula known as the DuPont Model, which is displayed in the accompanying table. The table has four columns: the dividend yield of these ten companies: their ROE, their dividend payout ratio, and their resultant estimated total return. The last measure is calculated as: one minus the payout ratio (the earnings retained on the balance sheet after paying dividends), times the ROE (that which the

[16] The DuPont Model was developed by the DuPont company in the 1920s and breaks down ROE into three distinct elements—profitability, operating efficiency, and financial leverage—in order to understand the source of superior (or inferior) returns in order to be able to compare companies in either the same or different industries.

company is theoretically capable of earning on the retained earnings), plus the dividend yield.

Utilities Select Sector SPDR (XLU) Ten Largest Holdings October 2014

	Yield	ROE	Payout Ratio	Theoretical Total Return
Duke Energy Corporation	3.2%	5.44%	100%	3.2%
Southern Company	4.5	11.22	82	6.5%
NextEra Energy Inc.	3.1	11.36	62	7.4%
Dominion Resources Inc.	3.5	13.96	88	5.2%
Exelon Corporation	3.6	8.22	58	7.1%
American Electric Power Co.	3.7	10.79	56	8.4%
Sempra Energy	2.6	10.09	59	6.7%
PPL Corporation	4.5	6.94	114	3.5%
PG&E Corporation	4.1	5.04	113	3.4%
Edison International	2.4	10.86	32	9.8%

Source: Morningstar, Company reports, Horizon Kinetics research

We can observe that, according to the DuPont Model, none of these securities can be expected to generate a double-digit rate of return. Most of them fall within the 3% to 7% range. However, that should not be confused with the *expected* rate of return. That is because the DuPont Model assumes that none of the utilities will actually have a regulatory problem which, unfortunately, many periodically do. Therefore, it could be argued that, at the present time, the DuPont Model return is really the maximum that can be reasonably expected to be earned. In an era when utility yields were higher, the DuPont Model did not represent the maximum because the inevitable utility crises were, to a degree, masked, or at least equilibrated, by the lower required dividend yields (higher share prices) attendant to years of declining interest rates. Since that is no longer the case, one is getting, at best case, the Dupont Model return minus a certain error return, whatever that error return is going to be.

To complete the discussion of XLU, its annualized rate of return from its December 1998 inception date to the end of September 2014 was 6.16%. And it was 6.16% not because there was no price appreciation among utilities due to declining interest rates. Rather, it was *despite* a favorable period of declining interest rates, because there were a sufficient number of regulatory and other problems to offset, in a relatively significant manner, what would otherwise have been appreciation realized from the underlying returns of the sound utilities, and the lower yields resulting from lower interest rates. Therefore, we can only wonder what might happen, not in a period of rising interest rates, but in period of merely stable interest rates.

SUMMARY

The decline in prices for solar-PV panels and batteries is making home power generation inexpensive enough to threaten the core businesses of electric utilities in every region of the U.S. Even so, stock prices of these utilities have increased greatly and are currently trading at record historical price/earnings ratios, and their bond yield spreads over Treasuries have narrowed as the market ignores the risk that residential electric customers may switch to solar.

The regulatory paradigm that has supported the recovery of utility capital investment has been in place since the electric utility industry reached a mature state in the first half of the 20th century, and capital investment is presently recovered over a period of 30-60 years, which clearly exposes the industry to stranded cost risks. While it appears that there are unprecedented challenges to the industry, until there is a significant, clear, and present threat to the capital recovery paradigm, it is likely that the financial markets will continue to ignore these disruptive challenges. That being said, the challenges have begun to emerge and are becoming more substantial at a rapid pace, to the point at which they will probably begin to impact electric utilities much more severely within the next 2-3 years, as populous states will then reach cost-parity between solar and grid power based on most research studies. Also, the dramatic rivalry between American and Chinese solar panel industries is likely to continue to yield substantial reduction in solar power costs over the next five years. Therefore, by the end of the decade, it is perhaps at least theoretically possible that homes and companies can get close to becoming self-sustaining with regard to their energy production, particularly in the sunnier states.

Left unaddressed, these financial pressures could have a significant impact on realized equity returns, required investor returns, and credit quality. As a result, the future cost and availability of capital for the electric utility industry could be adversely impacted, which would, in turn, lead to increasing customer rate pressures and rising defection rates.

Despite the potential impact of the risks outlined in this paper, they are not currently being discussed by the investment community, nor are they factored into the valuation of electric utilities' stocks and bonds in the capital markets. In fact, electric utility valuations and access to capital today are perhaps stronger than ever, reflecting the perceived relative safety of utilities in this uncertain economic environment. That is most likely a reflection of the fact that the current level of lost load nationwide from solar is less than 1 percent, even though the pace of change is increasing and will likely increase further as costs of disruptive technologies benefit from scale efficiencies. However, the historical success of utilities, such as they were, was based on quite marginal incremental demand; for the first time in history, just as true scale and cost economies are developing in rooftop solar panels, electricity demand in the U.S. has begun to contract. The question becomes what the impact upon utilities will be upon marginal demand contraction. Investors have developed confidence throughout time in a durable industry financial recovery model and, thus, tend to focus on earnings growth potential over a 12- to 24-month period. Using a longer time horizon of perhaps five years, it appears the changing industry fundamentals will have a powerful impact on all electric utilities, and on unregulated utilities in particular.

Based on the current trends in the market, demand for electricity from the grid is stagnant at best and may be declining meaningfully as alternative energy sources, such as solar, gain in popularity. In addition, because of net metering and the popularity of solar power, peaking plants could become obsolete within the next decade, and regulatory mechanisms need to be adjusted or overhauled to accommodate some utilities becoming the electricity generators of last resort. The net effect could be higher grid power costs (thereby exacerbating the consumer shift to solar and storage), lower average credit quality for regulated utilities and unregulated power producers, and increased recognition of the long-term threat to grid power. When customers have the opportunity to reduce their use of electricity or use solar-generated power at a lower cost, earnings growth for electric utilities could become very difficult to achieve. As this threat to growth becomes more evident, investors will become less attracted to investments in the utility sector. This will be manifested via a higher cost of capital and less capital available to be allocated to the sector. Investors today appear confident in the utility regulatory model since the threat of disruptive forces has been modest to date. However, the competitive economics of distributed energy resources, such as PV solar, have improved significantly based on technological innovation and government incentives and subsidies, including tax and tariff-shifting incentives.

While some unregulated utilities may become existentially challenged, others may merely experience stagnant earnings. However, a lack of growth (or anticipation thereof) may be all that is required for a substantial re-valuation of utility companies to take place in the stock market. If utilities are no longer perceived to have growth prospects, which implies that dividends will not increase either, then investors will probably demand a greater risk premium (which implies lower valuation) for holding these securities. Were they to trade at 11x trailing earnings and a dividend yield of 6%, metrics more consistent with historical valuations (notwithstanding the thesis that the future appears bleaker than the past), the shares could decline by 50% without necessarily appearing to be inexpensively valued.

Generally, asset allocators are unaware of the challenges facing the utility industry, as they have a tendency to extrapolate historical trends rather than consider the significant and perhaps disruptive changes the industry is currently experiencing. The asset allocators, who now operate on so-called factor models, consider historical dividend stability as one of the key performance factors, and accordingly, give it a very high weight. If utilities were to become unable to raise dividends, the required yields could easily rise from 3.5% to 5.5% during the re-valuation, which would result in a share price decline of 37%, assuming the dividends do not decline (which they might). Following such a correction, they would still trade at 14x trailing earnings (assuming stable earnings), which is not far from the historical valuation for utilities.

Asset allocation to yield-oriented stocks relies upon historical data regarding stability of dividends, which dates back decades. Allocators treat this data as near-immutable, as they would any scientific constant, like Planck's constant,[17] the gravitational constant, or the speed of light. They appear unaware that a dividend quality constant is likely to manifest a certain degree of inconsistency. That is not necessarily a problem. It is simply that, given the methodology used, there is no method of analysis to test periodically whether a variable remains constant, except when the variable actually changes. When a variable changes and everyone can see the change, stock prices will already reflect the new situation—and it will be too late. In that case, the models will be adjusted, but the problem is that they will all make the same adjustment simultaneously. That usually does not have good consequences for stock prices.

[17] Planck's constant is a fundamental physical constant characteristic of the mathematical formulations of quantum mechanics, which describes the behavior of particles and waves on the atomic scale, including the particle aspect of light.

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