CRA Insights:
Energy

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Latent risks in utility M&A

Five important questions for investors considering an acquisition

Investors have been drawn to the generally stable returns, lower cost of capital, and intriguing new investment opportunities electric utilities may present. Recent examples include planned or consummated acquisitions of Pepco Holdings, UniSource Energy Holdings (owner of Tucson Electric Power), and Nevada Energy. Despite the recent fervor, we see many reasons for investors to be cautious. While an acquired utility may deliver all of the promised returns to an investor, there are credible reasons why it may not. This could include a fickle customer base unwilling to support new technology investments that require rate increases, a regulatory environment that does not embrace advanced concepts in cost recovery, or an aging generation fleet experiencing increasing failures and driving up cost. Understanding how these and other uncertainties could affect the utility's performance is critical to evaluating an investment target.

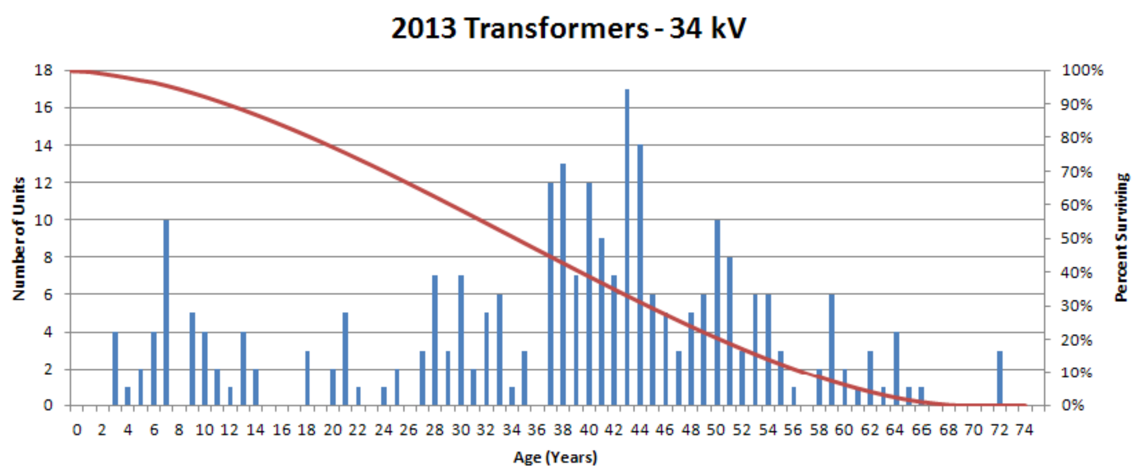
In this paper, we focus on five key questions that every strategic or financial investor should ask about a utility target. These questions focus on aspects of the utility's business that, from our experience, have been overlooked or not fully addressed by potential investors. These latent risks may have significant implications for an investor's valuation of a utility and should be fully understood and integrated into the analysis.

How old is the transmission and distribution system and how has it been maintained?

The country's aging electric infrastructure is well documented. Generally, utilities have not invested enough to keep pace with the degradation of the electric system. Broken poles and frames, line faults, transformer explosions, and bushing failures are increasingly common. All else being equal, increasing component failures lead to a higher frequency and duration of outages and higher costs, as unanticipated work tends to be more expensive in terms of labor and replacement parts.

The age of transmission and distribution assets varies significantly by utility and is generally a reflection of the utility's investment philosophy and the regulatory landscape. For example, Figure 1 is an age histogram for 34.5 kV transformers for the Northern Indiana Public Service Company (NIPSCO) system.[1] It is not uncommon to see a large population of system components that are significantly aged and at risk of failure. In Indiana, the legislature recognized this increasing risk to system reliability and created an alternative regulatory mechanism for utilities to accelerate system investment. However, in many other states, utilities do not have an effective mechanism for motivating investment and the average age of assets continues to increase.

Figure 1: NIPSCO 34.5kV transformer histogram and survivor curve



Source: Indiana Utilities Regulatory Commission Cause No. 44370

Investors should be wary of utilities with aging systems that have not found an effective means to recover necessary replacement capital. These systems may be at significant risk of failure and present financial risk to the investor in the form of disallowance, penalty, or lower approved returns. To avoid buying a utility lemon, investors should analyze data on system age and performance and review the historical relationship between depreciation and capital expenditures. If the average age of critical components is at or near expected useful life and if the average age of these assets is increasing annually, the utility may have an emerging problem.

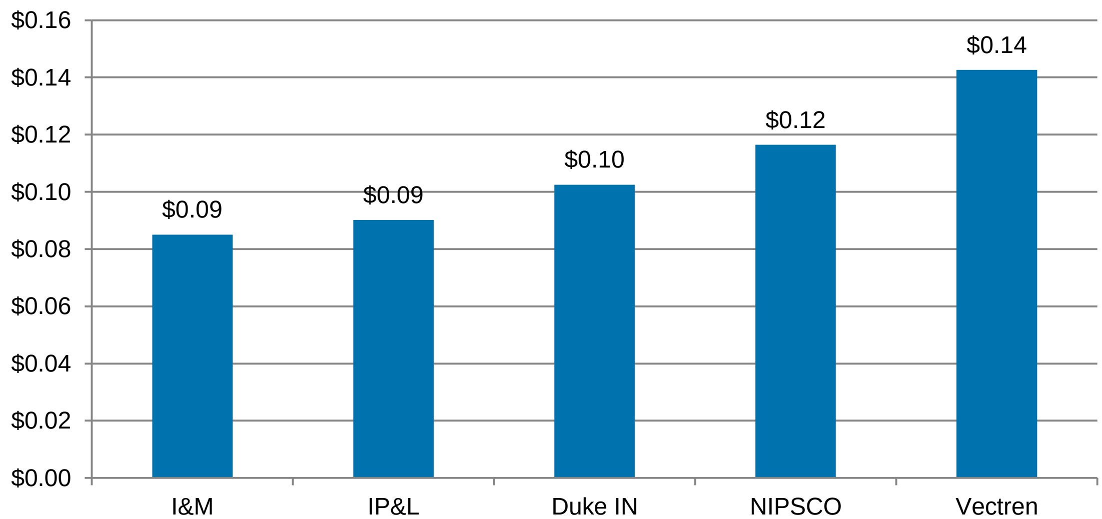
Investors should also understand utility spending on vegetation management, as falling branches or trees are common causes of electrical outages. While spending on vegetation management could indicate a utility is acting responsibly to maintain its system, it also could mask an increasing risk from aging system assets. Some utilities have used increased operations and management (O&M) spending to significantly improve reliability scores, despite limited capital investment. While this may be an effective strategy in the short term, the utility will need to address the underlying reinvestment issue eventually.

[1] *See* Indiana Utilities Regulatory Commission Cause No. 44370, NIPSCO filing, July 2013.

What type of headroom is there for rate increases?

Electric utility retail rates can vary widely by utility. Generation costs can vary based on fuel type, power plant type, and public policy goals. Transmission and distribution costs can vary based on the geography, population density, generation location, and technology type and vintage, among other things. Retail rates can differ significantly, even within the same region or state. For example, in Indiana, investor-owned utility retail rates range from 9 cents to 14 cents per kilowatt hour (see Figure 2, below). The highest rate utility, Vectren Corporation, absorbed significant environmental control costs for its coal plants ahead of many other utilities in the state. As these other utilities make their own environmental investments, their relative rate will likely rise as well and the gap may close.

Figure 2: 2013 bundled residential electric rates, Indiana



Source: Edison Electric Institute (EEI) Annual Rate Study

For an investor, it is important to understand the retail rate of a utility in the context of the in-state, regional, and national population. Utilities with higher relative rates are generally reluctant to spend capital if it means raising rates. These utilities can be at higher risk for regulatory disallowances if the perception is that they are "gold-plating" the system or operating inefficiently. This can be severely limiting for an investor hoping to earn increasing returns on investment.

Higher retail rates can also impede load growth and possibly lead to customer attrition. Large energy consumers, such as metals, plastics, and chemical plants, will locate in a service territory where they believe electricity costs are relatively low. Higher rates may make it challenging to attract new large energy customers. Even more devastating is the loss of a large energy customer that finds it more cost effective to relocate or install their own on-site generation. We have observed recent examples of large industrial companies co-developing combined heat and power plants that offer all, or a portion of, the company's electric requirements. In one case, this presented a significant loss of load to the jurisdictional utility that was forced to spread certain fixed costs over its remaining customer base.

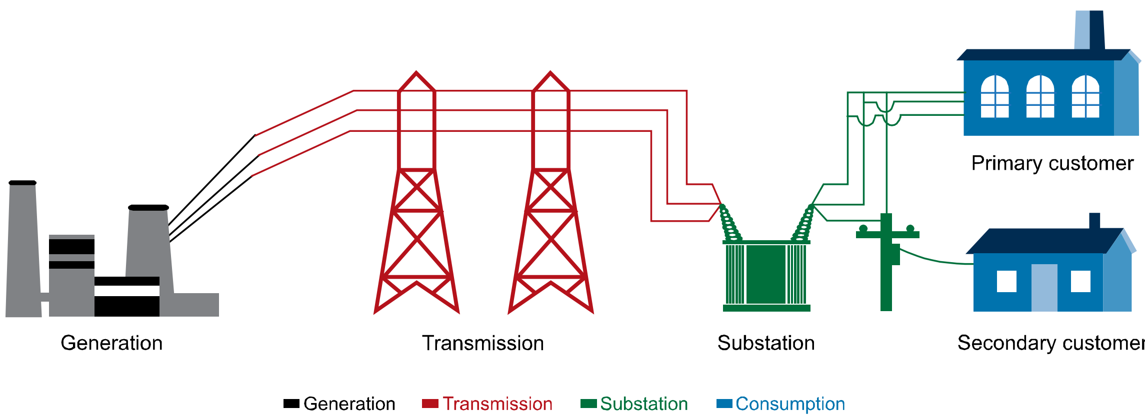
We recommend that potential investors in an electric utility run a rate analysis to compare a target's retail rates to a peer group comprising in-state and similarly situated regional entities.

Investors should unbundle the rates and examine the historical drivers for each of the components. This generally involves a review of Federal Energy Regulatory Commission (FERC) and state-level regulatory information (e.g., Form 1, Fuel Adjustment Clause detail). The rates analysis also should include a projection of future rates based on expected spending and sales for the peer utilities. This may require an examination of the peers' infrastructure and assessment of likely investment requirements.

What type of technology is currently deployed on the distribution system?

The simplest electrical systems comprise a collection of poles, wires, transformers, system protection devices (e.g., breakers, fuses), and meters. These systems perform the basic function of electricity distribution, but lack the hardware and software to enable the advanced functionality some customers now expect. This includes the ability to review daily or hourly usage trends, participate in demand response programs, and install on-site generation. Basic electric systems also lack automated measurement or reporting ability once electricity is delivered onto the distribution system. This means that most distribution-level outages need to be reported by customers, and utilities are generally forced to deliver higher voltages to the distribution system than would otherwise be necessary if voltage could be measured near take off points.

Figure 3: The traditional electric grid



Advanced electric systems include all of the basic electrical components described above, but also include additional substation, line, and metering devices, communications equipment, and back-end software applications. The following table describes some of the more common applications.

Table 1: Common advanced grid applications

Hardware/Software	Description/Function
Advanced relays & breakers	Advanced grids are fitted with relays that can be controlled remotely by the SCADA/DMS. Relays can monitor current, voltage, and frequency, and then send a command to breakers in the substation and on the lines (i.e., reclosers). This enables outage isolation and efficient restoration.
Current & voltage sensors and regulators	The advanced grid comprises numerous, strategically placed current and voltage sensors that enable the grid operator to detect faults and over- or under-current situations. In a fault situation the operator may be able to reroute power instantaneously to mitigate outages. In a low or high voltage situation, the operator can engage voltage regulators (in the subs or on the lines) to adjust voltage to optimal levels.
Advanced meters	Advanced meters can collect current, voltage, and phase angle data, then report this information to a central hub (called a headend) in near real time. The grid operator can send instructions to the meter, such as to shut down or report on status.
Communications & networking systems	Advanced grids rely on a combination of fiber optic cable and both private and public wireless networks to send and receive data from substations, feeders, and metering end points.
SCADA/DMS, OMS, CMS, MDMS etc.	In an advanced grid, the utility must install significant software to enable the full functionality of the installed hardware. This includes an advanced distribution management system (DMS) that is integrated with the supervisory control and data acquisition (SCADA), advanced outage management systems (OMS) and customer management systems (CMS), and a meter data management system (MDMS) to handle the exponential growth of data.

Utilities vary widely in technology maturity and investment. Some have made investments in all of the technologies described above, while others are undertaking pilot programs and proving out the benefits for their regulatory commission first. Some have done nothing at all and instead spend capital maintaining their basic electric system. Understanding the state of a utility's electric system should be important to potential investors for at least three reasons:

- First, utilities that heavily invest in new technologies, such as advanced meters or distribution automation, may face relatively high regulatory risk. States vary widely in their treatment of modernization investments. Some states, such as Ohio and Illinois, prescribe performance standards that the utilities must meet with the new technology. This could include meeting a desired reliability standard or a requirement to improve productivity. Utilities that perform below these standards could be at risk for regulatory disallowance, lost incentives, or even penalty.

- Second, utilities that have made recent, large regulated investments may have limited the effective "headroom" for additional investment, at least in the near term. For example, major utility technology investment programs tend to be expensive and often require rate increases. A utility may use significant political capital to gain approval for a plan, which could limit near-term system investment options for a new investor. On the other hand, these advanced electric system investments could enable a new class of utility investments that are not otherwise possible, such as distributed energy systems, electric vehicle charging stations, and in-home applications. A case-by-case analysis of rate sensitivity and customer expectations is appropriate here.

- Third, some utilities may have unwittingly limited future investment opportunities through past investment. For example, in the 1990s and early 2000s, some utilities invested in customer meters that could be read by a passing utility vehicle. These investments were justified in large part by staff reductions from eliminating manual meter reading. Today, many of these same utilities are contemplating replacing these second generation meters with the latest advanced meter technology. This may be difficult to justify. While today's advanced metering infrastructure offers numerous customer and system-wide benefits, most regulators still look to hard benefits like cost reductions in O&M when considering utility applications. This may make it challenging for a utility that has installed second generation metering technology to upgrade their systems, at least in the near term.

We recommend that potential investors perform a complete system assessment of any target, including an investment opportunity and risk analysis to identify how much capacity the system has for new investment and any heightened risks.

What are the company's viable generation and transmission investments?

Projecting a utility's realistic capacity for distribution investment can be challenging as it often reflects a balance between cost and functionality that may be difficult to predict. On the other hand, investment in generation and transmission is often a function of system requirements, statute, and regulation. This means it may be possible for an investor to gain a realistic sense for future utility generation and transmission investment through analysis.

Utilities that own generation generally need to maintain a certain reserve margin to ensure that sufficient power is available for customers. As load grows, plants retire, or contracts expire, utilities will need to add capacity, which could include a capital investment or simply a pass through expenditure. In any event, the utility's integrated resource plan often will provide a sense of the required investment. Investors should also understand the impact of environmental regulations on any plants owned by the company. Today, most utilities have announced their environmental compliance strategies, but these could change as new regulations are promulgated, particularly around carbon dioxide.

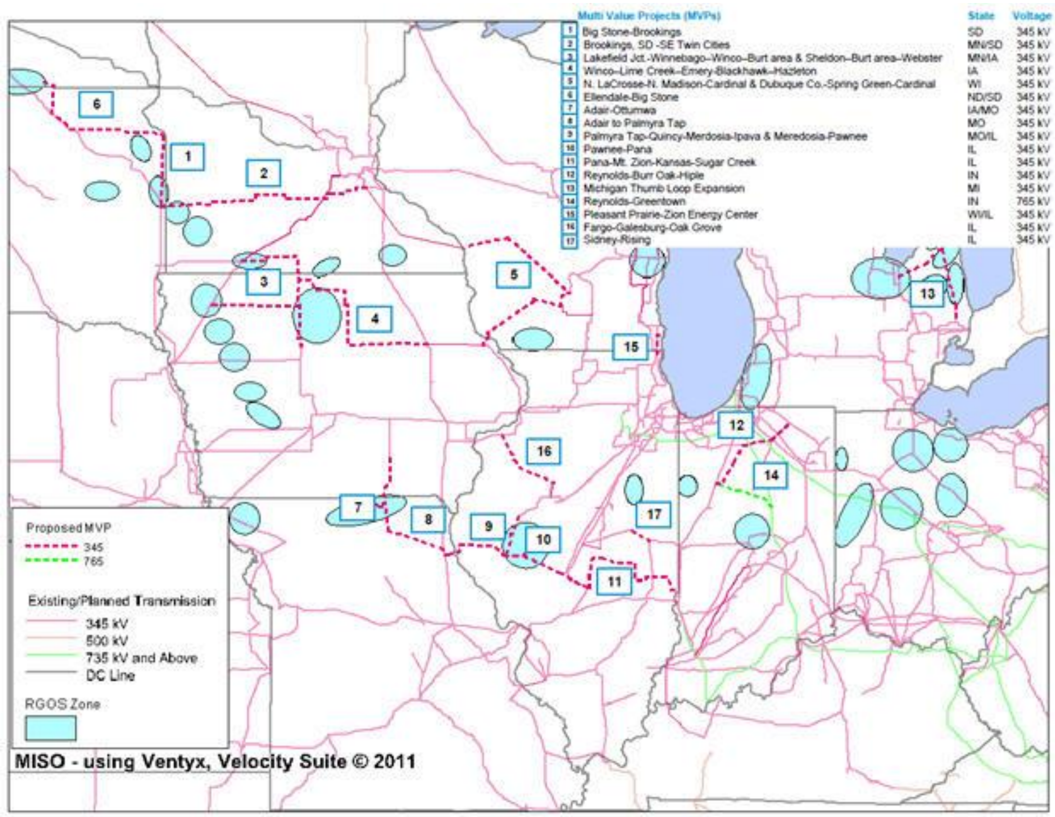
On the transmission front, we can break investment opportunities into two types. Compliance investments are required to meet load growth or a North American Electric Reliability Corporation (NERC) requirement, such as N-1 reliability.[2] Opportunistic investments may reduce congestion or bring some other benefit to a region, such as environmental. Utility transmission compliance investments may be straightforward to forecast, particularly in structured electric markets where

[2] N-1 refers to a NERC requirement that any single component of the bulk electric system has an independent back up to prevent outages from the failure of a single component.

the system operator requires utilities to file their transmission plans several years forward. Most utilities will have a sense for where transmission investments will be made based on load growth and emerging congestion points.

Opportunistic investments may be difficult to forecast. If a transmission investment only benefits customers in the utility's jurisdiction and is not required for compliance, the utility will need to weigh the benefits against the costs before investing, similar to distribution investments. The utility also may have an opportunity to participate in projects where costs will be allocated across a wider customer base, including other utilities' customers. These can be highly attractive investment opportunities for electric utilities, as the utility can earn a rate of return at least partly at the expense of other utilities' ratepayers. An example is the MISO Multi Value Project (MVP) portfolio, which contains transmission projects approved for cross-ISO cost allocation.

Figure 4: MISO approved Multi-Value Transmission Projects



MVP portfolio

Source: MISO

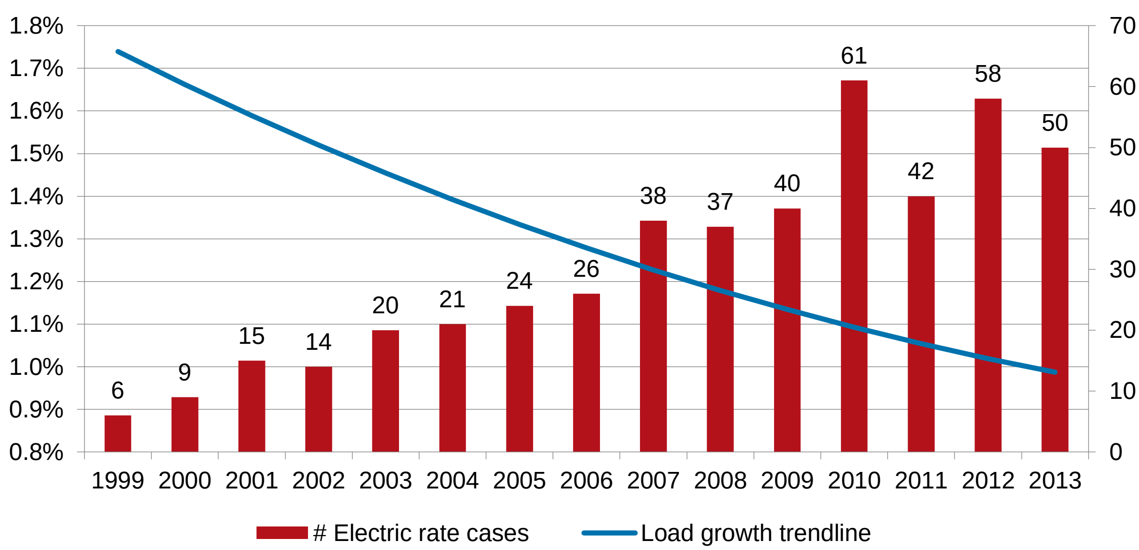
Investors considering an electric utility acquisition should make best efforts to understand and forecast generation and transmission investment opportunities and then build that value into the investment decision. Even if the likelihood of investment is not well known, understanding the opportunity is important. For example, a utility operating in a structured electricity market may have significantly different transmission investment opportunities than the same utility operating outside of the structured markets.

On the flip side, investors need to consider the threats to utility generation and transmission investment, particularly from distributed resources. As discussed above, behind-the-meter generation has become increasingly popular with customers. The scale and timing of distributed generation in a utility service territory will depend on a number of factors, including technology cost, resource availability (e.g., sunlight), regulatory structure, and customer expectations. Investors should evaluate the size of any threat and consider mitigation options.

How progressive is the regulatory model in the state?

Slowing sales, the rapid evolution of electric system technologies, the aging of electric infrastructure, and ever-shifting state and federal policies to encourage or discourage different types of system investment have exposed weaknesses in the traditional investment recovery model. Under the traditional model, utilities filed a general rate case when rates were no longer supporting the utility's authorized rate of return. This tended to be infrequent as utilities generally saw sales grow at a steady pace and could support both system expansion and replacement with the incremental revenue generated by these sales. However, as sales have slowed and customer service expectations have increased, utilities have found it necessary to seek rate increases more frequently. Figure 5, below, illustrates this inverse relationship between load growth and the frequency of rate cases.

Figure 5: Electric rate cases filed by year and US load growth %, 1999-2013



Source: US Energy Information Administration (EIA), CRA research

A general rate case may be an impractical solution for a utility that requires frequent rate increases. As a result, many utilities have sought rate "riders" or tracking mechanisms for costs that are difficult to forecast, investments made for regulatory compliance, and other major investment programs. In Pennsylvania for instance, utilities can recover investments made to "repair, improve, or replace certain eligible distribution property" through a special purpose charge. The utility must file a long-term investment plan and provide quarterly updates to the commission in lieu of filing a full rate case.

An investor should ask questions regarding the available recovery mechanisms for the utility and how those align with the expected system investments. If the utility is planning to significantly invest in the distribution system, does the utility receive any special treatment of those charges or do they need to be passed through a general rate case? An investor should also look at the historical relationship between the regulator and the utility to gain a sense for how future filings will be judged. In addition, an investor should understand whether regulators are elected or appointed, and how state politics may influence regulatory outcomes. For example, in 2010 the Florida Public Service Commission reduced Florida Power & Light's revenue request from $1 billion to $75 million, citing customer rate pressures.

Conclusion and recommendations

While the benefits of purchasing an electric utility may be significant and meet many of an investor's requirements for stable and fairly predictable cash flow, investors should fully understand the state of the utility's electric system, the realistic investment opportunities for the foreseeable future, and the regulatory framework that could enable or inhibit cost recovery. In our experience, investors, including utility buyers, find it challenging to fully identify and distill to useful analytics the uncertainty that surrounds an acquisition.

To ensure that a target utility's risks have been fully identified and valued, CRA recommends using an investment scorecard approach to systematically analyze key aspects of the utility's system and its operating environment. Our scorecard highlights ten areas of the electric utility business for review, from asset health to technology penetration. Answers to a set of structured questions about the utility's business isolate major and minor risks within each area and raise potential mitigation options. Ultimately, we work with clients to embed these risks into their valuation and to make strategic tradeoffs between potential candidates.

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