PJM Roadmap: Network Operations and Transmission Planning

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Ralph D. Masiello, PhD
KEMA, Inc.
4377 County Line Road
Chalfont, PA 18914
Office: (215) 997-4500 ext. 285
Mobile: (917) 860-0093
Email: ralph.masiello@kema.com

Ronald D. Willoughby, PE
KEMA, Inc.
3801 Lake Boone Trail, Suite 200
Raleigh, NC 27607
Office: (919) 256-0839 ext. 104
Mobile: (919) 744-8049
Email: ronald.willoughby@kema.com

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Introduction

This report is the key deliverable of a project conducted by KEMA in close cooperation with PJM, where a top-level strategy is presented for operating an interconnected transmission system employing Smart Grid technologies (highlighted in the report). Automation and system integration for transmission and distribution are considered, with value-added services being the major focus. Impacts on generation are considered. A framework is provided to facilitate industry growth. PJM and member companies are well positioned to participate in this growth.

PJM plays a significant role in advancing power systems technology as the largest centrally dispatched Regional Transmission Organization (RTO) in the world. PJM coordinates electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. In addition, PJM (acting neutrally and independently) operates the largest competitive wholesale electricity market in the world today. To ensure future electric reliability, PJM manages a sophisticated regional planning process for generation and transmission expansion.

PJM's more than 400 members transact much of their business over the internet, using on-line tools that provide real-time system data. This data is the basis for decisions on buying and selling power, arranging transmission services, scheduling contract purchases, carrying out business strategies, and making other critical business decisions.

This report explores how an RTO such as PJM can act to accelerate the development of beneficial "Smart Grid" technologies and their deployment on a regional basis. It considers how various aspects of the electric utility business environment may develop over time and what technology developments and RTO roles are favored or not favored under those scenarios. It also considers some environmental / technology developments that seem likely and which will require appropriate responses from the RTOs.

Executive Summary

PJM commissioned KEMA Inc. to work with PJM to develop a Roadmap of future scenarios of transmission operations and planning and how an RTO could respond to industry needs, utilizing technology, in these different scenarios. As part of this work, PJM and KEMA investigated different macro-economic, energy industry, and regulatory scenarios that might develop over the next decade and what challenges they would pose for the electric industry. Along with these "environment" scenarios, the study explored T&D, energy, and IT technologies that could become commercialized in the same time period and how they could/should be applied to respond to the needs that arose. Finally, and most centrally to the effort, the study explored ways that an RTO could respond to industry needs, including possible changes to it's current service offerings, technologies, and business models.

As part of the study, we prepared a number of case studies of other industries that offer insight to PJM as it explores possible futures. In each case study we focused on how technology was applied to improve services, add to service offerings, or to restructure the industry value chain. A number of useful insights were gained. The most critical insight was to look at how market mechanisms, rather than unilateral decision making, were used to adopt the industry value chain to end user objectives. It is our belief that within a large multi-state RTO footprint, no one scenario will fully describe the situations faced by the member transmission companies and the RTO. Instead, on a sub-regional basis, different elements of these scenarios will come to the fore or not based on political, economic, environmental, and other factors over time. Thus the scenarios are a kind of broad "describing function" which can be grouped in various mixes to describe a fairly complicated future evolution. An RTO might have to assume one role in part of its region or at one point in time and a different role (with respect to technology deployment) at another place and time.

The environmental scenarios were reduced to four.

The current environment is described as "Muddlin Through" – the industry faces a mixed regulatory and economic environment: interest rates remain low, utility mergers still go forward, market solutions are still in favor with federal regulators, some state regulators are moving towards increased demand side market solutions, renewable technologies are making inroads on the generation side, and federal support for transmission investment remains strong. Cash strapped utilities faced with rate freezes and prescriptive regulatory solutions to capacity and reliability issues focus on Distribution investments. The possible role that an RTO can play in this scenario includes facilitation of transmission investment, including automation and the development of market improvements to stave off regulatory roll back.

There are hopeful signs that the overall environment is moving toward a more optimistic scenario of "Choice and Rationality." In this case, the stresses for transmission investment are not so much that utilities are focused on Distribution by regulatory edict as that they are Performance Based Rates and by conscious management choice to emphasize core business. In this environment, An RTO can play a role not only as a facilitator, but possibly as a vehicle to move investment and risk to 3rd parties. An RTO, possibly outside the non-profit envelope, could become the managing investor or the owner's engineer operator in a variety of regional technology deployments around automation and IT aimed at asset management, productivity, and harvesting congestion.

The counter to this relatively positive world view is the "Shock Absorber" scenario where the RTO, caught between the regulators and the utilities, deals with unfulfilled needs as a mechanism for addressing problems that the utilities are unable to address due to an unfavorable investment and regulatory climate. In this pessimistic set of developments, the RTO can still act as a facilitator for technology deployment and transmission investment, and perhaps act to move associated utility capex costs to O&M costs by outsourcing, or even better, to grid tariffs by embedding some services in the grid charge. Technologies and services that will be in demand by an aging and stressed infrastructure such as asset management will be key, and any abilities of automation to address transmission capacity and reliability will be possibilities.

The above scenarios describe possibilities in the next 2–5 years. Over the next decade there is a possibility that things could evolve from "Rationality and Choice" to "Future Grid" where the electricity infrastructure enjoys its own modest version of Internet style rapid improvement and evolution. Technology frameworks such as "Smart Grid" and "Utility of the Future" including advanced metering, Time of Use Rates, and penetration of alternative resources, hybrid/electric vehicles, and other disruptive technologies will put stresses on planning, operations, and market operations at the ISO and the utility level. It will fall to the RTO to help wholesale suppliers and the market adjust to an era of increased customer choice not only of supplier but of how much supply and how; and to deal the intersection of retail and wholesale competition and supply.

As with any crystal ball gazing effort to develop future scenarios, there are unknowable future shocks that dramatically alter how the world evolves. A number of these are identified but it is not realistic for the RTO to build plans around them as much as to be aware of the possibilities as decisions are taken and investments made.

Under all these scenarios, critical technologies to watch include digital protection and Intelligent Electronic Devices in the substation, on the distribution overhead, and at the meter. Today these have penetrated distribution substations heavily – with well over 90% market share and perhaps 60% installed base share. At the transmission level, adoption and penetration has lagged due to lack of new construction, lack of a reliability driver, and basic conservatism. In both cases, utilities are failing or moving slowly to exploit the information these devices can provide via Substation Automation to improve reliability, make operations more efficient, and to enable asset management – meaning predictive maintenance, life extensions, and improved planning. These technologies link to new technologies in communications – wireless, broad band over power – as well as new security concerns. They also link to new IT technologies for systems integration and data mining as well as new analytics for operations and asset management.

One important theme that arises in our investigation of other industry development models is that information technology and deregulation ultimately act not only to transform the value chain but to make end customer choice and input much more important all the way back up the value chain. Manufacturers build to order; retailers stock and ship to order; delivery mechanisms and quality of service are chosen by the consumer. Ultimately Smart Grid technologies will act not only as reliability/quality/productivity enhancers but as choice enablers. The role of the RTO as an information management organization in this world will become more and more important.

There are also new transmission technologies which have or will become commercially viable and where the RTO will play a role in facilitating their adoption. These include transmission repowering and reconductoring as the most attractive means of adding capacity, followed by devices which provide a measure of enhanced control and flexibility such as FACTS devices, high speed switching, static var compensators, and the like. Advanced underground technologies may also play a role. Further over the horizon and in a more niche role will be superconducting technologies.

Different financial drivers will motivate the industry to adopt these technologies under the different environmental scenarios. In each case there are possible roles for the RTO to play ranging from a technology facilitator to possibly an asset owner/provider. The latter is especially true of technologies associated with providing, managing, analyzing, and exploiting information. A particular niche opportunity in this regard which is a natural extension of RTO core competence is associated with utility transmission operations – control centers. Here, the scale opportunities afforded by an RTO as a technology provider and an outsourcer as well as possibly an operations outsourcer are likely to be compelling.

There are a number of industry evolutions which are short-term, high probability and which will necessitate changes in RTO services and technologies around planning, market operations, and reliability operations. Many state PUCs are exploring or mandating Time of Use rates and Advanced Metering to support them, with demand response as a primary driver. This will have major implications for market operations and will likely include revamping of wholesale revenue metering and settlements systems. Global warming and the imposition of a regime of carbon caps and trading will have implications for energy markets, permit tracking, and ultimately market operations, capacity markets, and reliability. There are a number of ways these could develop. Third, increased penetration of distributed generation and renewables bring complexities in market operations and reliability, particularly around outage scheduling.

For each of these “near certain” evolutions a white paper is provided as an appendix to this report that attempts to lay out the issues and possible RTO responses. In particular, we recommend that the RTO move to further develop these concepts and possible responses. The objective is that the RTO should be proactive in articulating the issues and alternative solutions that will not jeopardize market operations and reliability.

Finally, of the industry needs and possible RTO responses, a prioritization is suggested for further exploration by the RTO leading to strategic decisions around the RTO business models and investments.

1. Scenarios for Electric Power Industry Developments – Industry Needs and Possible RTO Responses

Forecasting future business and socio-economic scenarios is always difficult and in the end, unforeseen technological or political disruptions can dominate events in ways that the scenario builders did not anticipate. Absent such "Wild Cards" this report posits a spectrum of electric energy business scenarios which incorporate regulatory and economic drivers and adoption of technologies and market innovations as results of those drivers.

These scenarios are developed fully in Appendix E and are summarized in this section. One element that is constant in all scenarios is that US population will continue to grow and this alone makes it hard to see load growth stalling in the next decade. Even major energy supply side shocks (another oil embargo or rapid imposition of tough carbon limits) will likely result in "fuel switching" towards electricity by many energy sectors.

The current environment is described as "Muddlin Through" – the industry faces a mixed regulatory and economic environment: interest rates remain low, utility mergers still go forward, market solutions are still in favor with federal regulators, some state regulators are moving towards increased demand side market solutions, renewable technologies are making inroads on the generation side, and federal support for transmission investment remains strong. On the other hand, high fuels prices cause retail rate push back and calls for re-regulation at the state level, and local environmental concerns restrict many transmission and generation investments. Cash strapped utilities faced with rate freezes and prescriptive regulatory solutions to capacity and reliability issues focus on Distribution investments. The possible role that a RTO can play in this scenario includes facilitation of transmission investment, including automation and the development of market improvements to stave off regulatory roll back. A key role may be the creation/facilitation of ways to attract 3rd party investment for transmission enhancements such as re-conductoring or re-powering which are less likely to meet local environmental resistance.

There are hopeful signs that the overall environment is moving towards a more optimistic scenario of "Choice and Rationality." In this scenario the broad economic environment remains favorable, load growth continues, energy prices remain high but are stable, and most importantly regulators and politicians understand the need for infrastructure investment and continue to support market-based solutions. In this case the stresses for transmission investment are not so much that utilities are focused on Distribution by regulatory edict as that they are Performance Based Rates and by conscious management choice to emphasize core business. Transmission becomes a pure asset and ROI recovery play for utilities and a variety of "bandwidth" issues (aging workforce, limited management attention, etc.) put transmission technology investment in a back seat. In this environment an RTO can play a role not only as a facilitator but possibly as a vehicle to move investment and risk to 3rd parties. An RTO, possibly outside the non-profit envelope, could become the managing investor or the owner's engineer operator in a variety of regional technology deployments around automation and IT aimed at asset management, productivity, and harvesting congestion. In any case, as regulators and industry look to market solutions to a host of energy issues, it will fall to the market operator to implement if not proactively conceptualize the solutions. The section in this report on "Industry changes Requiring An response" and the three related white papers in the appendices expound further on carbon trading, demand side markets and settlements, and outage scheduling as such issues likely to come to the RTO's doorstep.

One important variation to this "choice and rationality" theme is a continued unbundling of energy retail and energy delivery (in other words, the UK model). At the moment most of the US is seeing slow growth if any in retail competition. However, in some regions where large rate increases are on the table due to ending rate freezes, regulated distribution rates get squeezed as part of the regulatory reaction. This can leave T&D utilities in a kind of "coffin corner" where PBR penalties decrease funds available to maintain the distribution system and reliability suffers still more. The specter of such a future has led some utilities to start thinking about recovering distribution revenue requirements via "connection" or "capacity connection" fixed charges instead of a per usage charge – as is the case today with much of telecommunications. Such a model would trigger larger changes in the delivery vs. supply vs. information supply value chains.

These two scenarios describe a "not bad" current situation which is moving, however haltingly, towards a more attractive state of affairs. The counter to this world view is the "Shock Absorber" scenario where the RTO, caught between the regulators and the utilities, deals with unfulfilled needs as a mechanism for addressing problems that the utilities are unable to address due to an unfavorable investment and regulatory climate. In this scenario, the economic and regulatory environments become unfavorable – higher interest rates, slower growth (although load growth is still present), rate freezes or rollbacks, a broader regulatory turn-away from market solutions all unfold. Regulators turn to "prescriptive" solutions to load growth, rate increases, and reliability issues. This leads utilities into a more confrontational mode of operation where no significant investment is made other than as a result of a regulatory decision. This behavior also tends to impede the deployment of renewables and DG. Rather than demand side markets, demand management top down (think water rationing in the West during a drought) becomes the solution to capacity shortages.

In this pessimistic set of developments, the RTO can still act as a facilitator for technology deployment and transmission investment, and perhaps act to move associated utility capex costs to O&M costs by outsourcing, or even better, to grid tariffs by embedding some services in the grid charge. Technologies and services that will be in demand by an aging and stressed infrastructure such as asset management will be key, and any abilities of automation to address transmission capacity and reliability will be possibilities. In this scenario, the RTO will have to work even harder at the regulatory and utility management levels to bring about the necessary changes and to "fit" them into the objectives of the varying stakeholder groups. No matter what, it will fall to the RTO to address the market operator requirements of various prescriptive solutions and even penalties that regulators conceive.

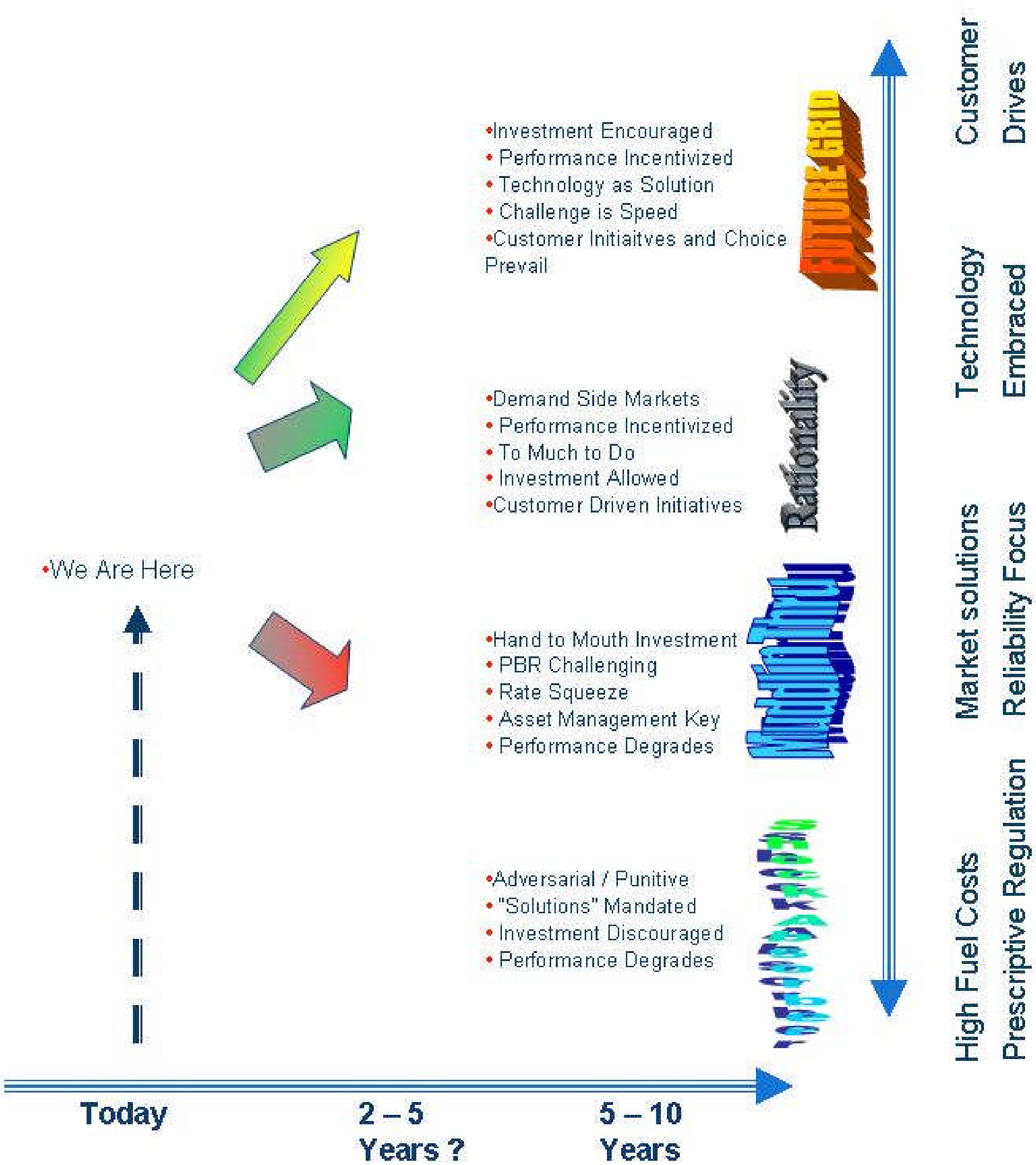
There is a much more optimistic world view of a “Future Grid” where the electricity infrastructure enjoys its own modest version of Internet style rapid improvement and evolution. The utility industry has so far resisted almost all “disruptive new technological change” with the possible minor exception of the combustion turbine. The fundamentals of electric power generation, transmission, and distribution are unchanged over the past century. In particular, the silicon intelligence era has only affected the industry in a minor way by enabling better grid control and thus the advent of market solutions superimposed on a naturally monopolistic transmission structure. The combination of utilities’ ability to “manage” competitive threats and ongoing regulation, together with an industry reluctance to abandon long-lived infrastructure, has kept disruptive forces at bay. Industry disruption triggered by technological change has always required the perceived ability for an entrepreneur to make a fortune as a key element.

There are technologies on the horizon which may finally break through the regulatory/monopoly barrier. In particular, the concept of “Smart House” coupled with DG and TOU rates – especially if spurred by electric vehicle developments, could be that change. Other touted technologies such as “Smart Grid” and use of solid state flexible AC devices are probably more evolutionary than revolutionary and fall under the “Rationality” scenario. The demands upon the RTO should such a revolution come about will be similar to those in the “Rational Choice’ scenario but will be more intense and will happen faster. Consumers in “Future Grid” will demand flexibility and increased capabilities from the distribution utilities in order to support these technologies. It will fall to the RTO to help wholesale suppliers and the market adjust to an era of increased customer choice not only of supplier but of how much supply and how; and to deal the intersection of retail and wholesale competition and supply.

Consumers so far have been relatively unexcited by “Smart House” and smart appliances interacting with TOU pricing – the savings have not been that great and the technological complexities and costs outweigh any perceived benefits except for the electronically addicted. However, the possible adoption of hybrid and electric vehicles coupled with availability of DG and distributed renewables could be the compelling element in a change in customer behavior. The RTO should pay attention to the statistical indicators and new product developments that would be indicators of such a change.

Finally, there are a number of “Wild Card” events that can change the environment in major and unanticipated ways. Major political events that disrupt energy economics are clearly among these as are “out of nowhere” new technologies for energy supply not on anyone’s radar screen today. These sorts of things could include the fairly obvious – an oil embargo, Mid-East war, or the like; or cheap solar roofing; – and could also include things from the realm of science fiction – “cold fusion” for example. The report has already pointed out that most fuel supply side disruption will act to encourage fuel shifting to electricity and will likely accelerate DG deployment. Disruptive technologies in electric production would have the same effect. However, should the RTO find itself in the role of facilitating 3rd party investments or even acting as a managing investor or owner's engineer/operator, then like any investor, the RTO has to ask the question "what could disrupt this" and assess the risk.

These multiple scenarios are shown graphically in figure 1-1. They are described in much greater detail including the role of the RTO and other industry players in each case, in Appendix H.


•Investment Encouraged
• Performance Incentivized
• Technology as Solution
• Challenge is Speed
•Customer Initiaitves and Choice Prevail
FUTURE GRID
•Demand Side Markets
• Performance Incentivized
• To Much to Do
• Investment Allowed
•Customer Driven Initiatives
Rationality
•We Are Here
•Hand to Mouth Investment
• PBR Challenging
• Rate Squeeze
• Asset Management Key
• Performance Degrades
•Adversarial / Punitive
• "Solutions" Mandated
• Investment Discouraged
• Performance Degrades
Customer Drives
Technology Embraced
Market solutions Reliability Focus
High Fuel Costs Prescriptive Regulation
Today
2 – 5 Years ?
5 – 10 Years

2. Other Industry Business Models

In recent years, much has been made in business and popular literature regarding how automation, and in particular, work flow software and systems exploiting the Internet has caused all manner of industries to fragment and re-arrange their value chains. In the process, opportunities have arisen for new enterprises that focus on hitherto integrated elements of value chains. Indeed, this is a major theme of Thomas Friedman's Pulitzer work, "The World is Flat."

The greatest changes, and therefore the most buzz, have been around manufacturing and service industries driven by purely capitalist business models. However, this does not mean that franchised, monopolistic, regulated, and governmental activities have been immune to these changes. This section of the report summarizes a few examples which are germane to the electric power industry and in particular to the question of the role that RTO/ISO can play in exploiting IT and automation. These include franchised and regulated transportation industries and services pertaining to them; industries focused on operating long lived capital assets, and energy industry examples of changed ownership models.

Exhibit 3-1 shows these examples positioned in the dimensions of regulated/unregulated and franchised/unfranchised. Appendix F of this report goes into some detail in each case and examines the structure of each, how successful the model has been, the exploitation of automaton, and lessons that the RTO can draw from the example.

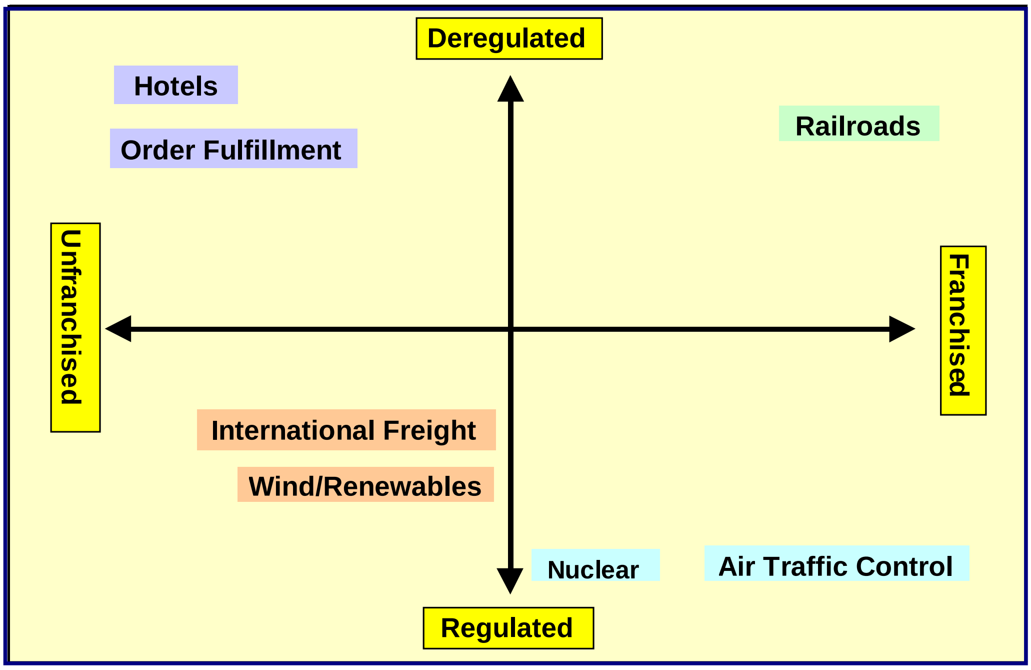


Exhibit 2-1: Structure Map of Industry Examples

Two examples are cautionary – the privatization of British Rail and the US FAA. In both cases, agencies which provide needed transportation infrastructure for scheduling and operations and in the rail case, also own/maintain the infrastructure. Both cases are examples of failures to operate efficiently with end consumer (public) frustrations over delays. Both may have been subject to governmentally imposed funding limitations, but the lavish sums expended by the FAA on IT systems would seem to belie that. A completely different factor may be (this is a speculation) that the fundamental model for scheduling prioritization and access is, in both cases, not truly market-based and is similar to pre-deregulation models. As a result, the stakeholders have little incentive to integrate their IT systems with the infrastructure operator and market-based changes in operations and productivity improvements fail to materialize. In order to see this, consider the ability of light aircraft to add to runway delays at airports, or the ability of commuter flights to add to routing delays and runway holds. A market-based system to alleviate congestion (in a twist, adopting electric or gas industry models) would act to alleviate this problem and impose TOU pricing on consumers. Instead airport gates are used as a poor proxy for congestion markets. Note: On the other hand the FAA's safety record is extraordinary and could be considered the world leading example. To that extent, these comments may seem "unfair."

Railroads are often a favorite business school example of an industry that characterized itself too narrowly and "lost out" to technology developments. Railroads did not think of themselves broadly as *transportation* businesses and lost out to trucks and air freight over time. A focus on regulatory strategies to fight deregulation as opposed to diversification strategies can lead to this kind of tunnel vision.

Package delivery companies today are multi-modal and provide consumers with both choices and information. Their services are tightly integrated with information based retailers (eg Amazon) and the information they provide to the consumer is integrated with the retailer's information stream – order tracking, for instance.

This is a possibility that electric power transmission and distribution companies (and RTOs, by extension) have to consider. Their business could be at risk if they only consider themselves as electric energy delivery companies and fail to "diversify" into being providers of data and useful information about electric energy. As new electric energy related technologies (storage, renewables, DG, smart meters ---) are deployed at the consumer level the choices and decisions of the consumer will become paramount. This is a difficult transition for any regulated industry. RTO's are uniquely positioned to be key players in this transition as they are purely information companies today.

While this report did not explore the analogy of competing exchanges, it is worth noting that when financial instruments or commodities are traded on multiple exchanges, the "consumer" has a choice of exchange. Whether and how this model might develop for RTOs – which are inherently sole provider functions today in their footprint – is a question to ponder.

The nuclear industry is an example where large operators can exploit efficiencies and competencies to provide outsourced operations for smaller asset owners. This is a similar unbundling to the hotel (REIT) industry where the chain provides a host of services to the franchisee who basically is an asset owner. However, the nuclear industry is heavily regulated and the core competence of the operator is in dealing with regulatory prescriptive safety requirements efficiently. Innovations in operations are proscribed and as a result for years the nuclear industry did not adopt the latest automation technologies. The hotel industry, on the other hand, is lightly regulated and the chains exploit IT for supply chain management, reservations, customer loyalty, and integration with other travel industry providers such as airlines, travel agents, rental cars, etc.

Order fulfillment and Ocean Freight are examples of industries where the heavy use of IT, automation, and work flow systems integration are essential to a restructuring of the value chains of many industries that utilize their services. In the former case, the industry is neither franchised nor heavily regulated and is heavily competitive; in the latter, the port operators are key players in the process and are franchised and locally monopolistic.

What are the lessons for the RTO from these examples?

RTO core competence lies in building and operating systems that handle large amounts of real-time information related to energy infrastructure operations both from the market participants' standpoint and public safety/reliability standpoints. Asset ownership and financial engineering are not core competencies and are inherently in conflict with non-profit status and culture. In between these two "extremes" lies the RTO's ability to mediate conflicting stakeholder objectives including the public interest.

Aligning stakeholder interests with key measures of "success" would seem to be a key factor in the relative success of these models. These measures can include the profitability of the stakeholder businesses but are better defined in terms of the perceptions of the ultimate consumer at the end of the value chain – in most cases the public. Market mechanisms are the most effective way to accomplish that alignment on an ongoing basis. The lack of effective market mechanisms would seem to be a factor in the deficiencies cited in the FAA and British Rail examples on the one hand and a clear factor in the ocean freight and order fulfillment examples.

RTOs / ISOs have gone through sometimes painful iterations of market model development to arrive at market models that "work" in terms of reliability, transparency, and robustness. Going forward, the attractiveness of an RTO operation to participants will become more and more important. Towards that end, we have incorporated an example – a white paper on a market based solution to scheduling generator outages as a vehicle to better serve participants.

Another RTO core competence today is the ability to analyze new or changed market mechanisms and then to articulate their effectiveness and impact on overall electric sector performance. Therefore, the

RTO should have the ability to shape the evolution of the value chain, as suggested in Section 4 and Appendix F, in ways that improve its probability of success.

3. Changes in RTO Business Models that can Facilitate Addressing the Challenges

To respond to industry needs that are anticipated in the various industry scenarios, the RTO may need to evolve its business model to fully step up to the different situations. This section describes different business roles that the RTO can take with regard to a number of possible technology/solution/infrastructure investments.

3.1 The Business Model Spectrum

Exhibit 4-1 below provides a number of alternative roles that the RTO can take ranging from Technology Provider to Owner/Investor. There is, of course, an existing role which is “Non-Profit Grid and Market Operator” – the status quo. We believe that this role is well understood and a number of technology deployments can certainly be placed in that context. This section deals with other concepts that do not fit that model.

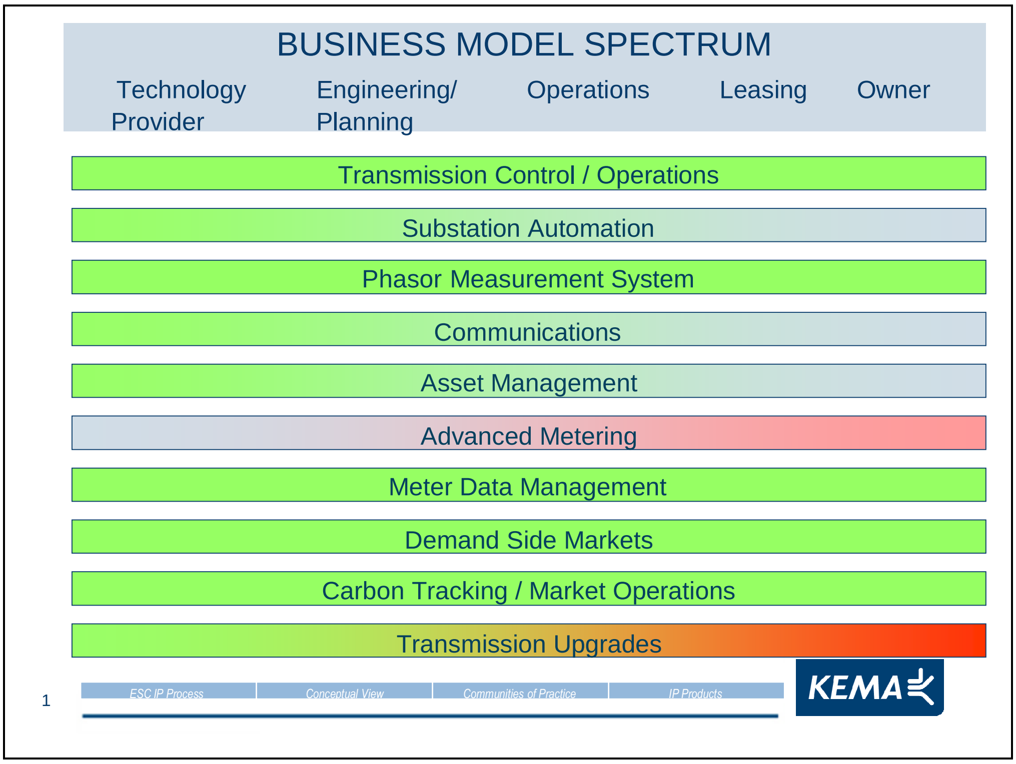


Exhibit 3-1: Business Model Spectrum

In Exhibit 3-1, colors are used to indicate the practicality/attractiveness of the different roles in each automation case; green is positive and red is difficult.

Technology Provider is a business model where the RTO develops, funds, and deploys technology for its own use and then makes it available to transmission utilities on some – typically licensed - basis. The basic concept is that many of the IT and automation technologies are expensive to develop. The RTO can amortize the costs of these and perhaps attract outside investment as well by reselling or leasing them to transmission companies, 3rd party providers (including technology companies), or to other ISOs. A lower risk alternative would be for the RTO to collect royalties from 3rd party developers of the technologies. This is probably the easiest and most natural evolution for the RTO to take – it capitalizes on the RTO brand and utilizes in most cases RTO core competence in large scale/real-time IT technology. Perhaps most importantly, it does not put the RTO in direct competition with the T&D utilities as asset owners and instead offers a value proposition to them of reduced cost and risk – a kind of high tech supply chain management as well. It does create the possibility of putting the RTO in competition with technology developers/suppliers but that is a more manageable and less conflicted position.

In many of these examples, the RTO could use technology economies of scale to address aging workforce constraints or even to provide access to offshore outsourcing (think settlements – if retail settlements become a major activity this could be a logical opportunity for consolidated outsourcing). In other cases, the efficiencies of a single supplier (Meter Data Management) are glaringly obvious and do not conflict with any market/independence considerations.

The Engineering/Planning role is one already thrust on the RTO in its role as an RTO. It is not illogical to extend today's system level planning function to more detailed engineering. Utilities that see transmission as a pure asset investment business will not resist outsourcing the engineering to an RTO, although middle management and engineering staffs will see this as a threat. Doing the engineering of various automation technologies will link nicely to a regional supply management role and produce cost savings and efficiencies as well as improved quality over time. This is probably more natural than doing substation construction, for example.

The Operator role is one that comes naturally to the RTO today and extending it to additional IT systems is another way to capitalize on the RTO brand and core competencies. And in some of these areas the market would expect the market operator role to be filled by an entity like the RTO in any case. Utilities might well accept outsourcing Transmission operations completely to an RTO if liability issues could be solved. This is a logical extension of RTO competencies and technology and can be expected to yield great economies of scale. It also dovetails well with the "Technology Provider" role.

It is when we talk about "Leasing" and "Owning" that the appropriateness of a changed RTO role becomes more difficult. Utilities will still want the opportunity to earn a regulated return on transmission investments and will view any intrusion by an RTO as hostile to their interests. And it is not realistic to think that the RTO could obtain lower cost capital than a viable utility. While leasing in theory offers the utility the chance to capitalize the lease and earn a return (typical with IT assets today) the financing organization and the RTO have to earn a return on the capital employed as well. It may be that the RTO would better serve the utilities by having a financial institution(s) as partners in constructing these models. Arguably, financial engineering is not a core competence for the RTO today and is difficult to acquire to the degree needed to be competitive with a GE Capital.

Owning raises greater difficulties – it is then not possible for the utilities to treat payments to the RTO as other than O&M expenses and they will definitely not welcome the loss of the opportunity to invest themselves. The exception to this situation is when the payments for using the asset can be passed to energy suppliers as part of the grid tariff, or some variation on that mechanism. Then it is possible that utility management would welcome the ability to see an expense moved away from their rates. Activities which naturally fit the Operate role such as demand side markets and MDM logically fit in this category. IT systems for asset management and substation automation, on the other hand, represent the RTO intrusion into utility activities and will require a compelling case to be developed as with Transmission Operations, above.

In particular, transmission upgrades and retail meters seem to be assets where the RTO would have difficulty in finding a role beyond its natural role as market developer, planning, and possibly technology provider for associated IT. Communications, on the other hand, is an area where utilities are accustomed to outsourced provision and where rationalization and upgrades are needed in many cases today. Communications, as with IT systems, is another logical are for the RTO to investigate across the business model spectrum.

4. Current and Future Technologies for the Grid of Tomorrow

Considering most of the installed electric infrastructure was designed to meet the demands of an analog, stand-alone industrial economy, the installed infrastructure is populated with equipment ranging in age from a few years to more than 50 years. Often referred to as "legacy equipment," this is a tremendous asset base composed of an assortment of technologies. As today's economic and societal needs evolve into a digital, networked world, technology is expected to provide an upgrade path capable of meeting increasing performance levels. Information collection and data management are central to meeting reliability and economic performance targets.

Meeting these targets will require using new technologies in a systematic and methodical manner. Improved grid reliability, enhanced customer service, and improved operational efficiencies will require information integration across the enterprise using enhanced levels of automation.

Rapid adoption of such technologies is expected in the coming decade for several reasons. First, consumers are demanding greater efficiency and capability from the grid. Distribution systems must achieve more for less in the next round of capital expenditures through judicious use of measurement, management, monitoring, equipment, and operations technologies. Second, for the first time, large investments must be to upgrade and protect power quality as well as reliability. This concern is driven by the explosion of the "digital economy." Finally, since the last time the electric grid was modernized, integration of computing and networking devices allow sophisticated communications throughout the grid. The electromechanical grid of the 20th century is being transformed into a Smart Grid of computers and electronics in the 21st century.

Exhibit 4-1 compares 21st century technologies with those in use today. Clearly, advanced communications and automation play a pivotal role.

Table 1 — The Smart Grid of the Future	
20th Century Grid	**21st Century Smart Grid**
Electromechanical	Digital
One-way communications (if any)	Two-way communications
Built for centralized generation	Accommodates distributed generation
Radial topology	Network topology
Few sensors	Monitors and sensors throughout
"Blind"	Self-monitoring
Manual restoration	Semi-automated restoration and, eventually, self-healing
Prone to failures and blackouts	Adaptive protection and islanding
Check equipment manually	Monitor equipment remotely
Emergency decisions by committee and phone	Decision support systems, predictive reliability
Limited control over power flows	Pervasive control systems
Limited price information	Full price information
Few customer choices	Many customer choices

The U.S. National Energy Technology Laboratory describes grid modernization in terms of seven key characteristics:

1. **Self-healing.** A grid able to rapidly detect, analyze, respond and restore from perturbations.
2. **Empower and incorporate the consumer.** The ability to incorporate consumer equipment and behavior in the design and operation of the grid.
3. **Tolerant of attack.** A grid that mitigates and stands resilient to physical and cyber security attacks.
4. **Provides power quality needed by 21st century users.** A grid that provides a quality of power consistent with consumer and industry needs.
5. **Accommodates a wide variety of generation options.** A grid that accommodates a wide variety of local and regional generation technologies (including green power).
6. **Fully enables maturing electricity markets.** Allows competitive markets for those who want them.
7. **Optimizes assets.** A grid that uses IT and monitoring to continually optimize its capital assets while minimizing operations and maintenance costs.

Exhibit 4-1: The Smart Grid of the Future[1]

Appendix A provides a *Technology Opportunity Matrix* with technologies grouped into three main categories: Automation and System Integration, Transmission, and Distribution. Each category is broken into specific technologies that can be deployed in a 5 or 10-year window. An assessment is then provided (Appendix A.2) for each using the following criteria: Operation, Reliability Performance, Asset Management, Critical Success Factors, RTO Added Value, Steps to Achieve, Cost, Benefits, and

[1] Source: The Emerging Smart Grid, Global Environment Fund, October 2005

deployment period (5 or 10 years). Appendix A.1 (repeated below as Exhibit 5-2) presents an assessment summary that focuses on relative costs, benefits, deployment period, and RTO added value. Highest potential areas are highlighted.

SUMMARY	Low-1	High-5	Deployment		RTO Added Value
Technology	**Cost**	**Benefits**	**5 Yrs**	**10 Yrs**	**Y or No**
Automation and System Integration					
Advanced Sensors	2	3	X		**Y**
Advanced Monitoring	3	**5**	X		**Y**
Advanced Communications:					
- Wireless	2	**5**	X		**Y**
- Broadband over PowerLine Carrier (BPL)	1	4		X	**Y**
- Ethernet over Fiber	**5**	4	X		**Y**
Data Concentrators	1	3	X		**Y**
Interconnected Comm's Infrastructure:					
- Wide Area Networks (WANs)	2	**5**	X		**Y**
- Local Area Networks (LANs)	2	**5**	X		**Y**
- Home Area Networks (HANs)	4	3		X	**Y**
Digital Protection	3	**5**	X		**Y**
Phasor Measurement Units (PMUs)	2	**5**	X		**Y**
Transmission					
Advanced Switchgear & Controls	2	3			**N**
FACTS Devices:					
- Static VAR Compensators (SVCs)	**5**	4	X		**Y**
- Static Compensators (STATCOMS)	**5**	4	X		**Y**
- Thyristor-Controlled Series Caps (TCSCs)	2	4	X		**Y**
- Advanced HVDC	**5**	2		X	**N**
Advanced Power System Stabilizers (PSSs)	1	**5**	X		**N**
Light Weight, High Temp OH Conductors	3	**5**	X		**N**
Superconducting Cable	**5**	**5**		X	**Y**
Distribution					
Volt/VAR Control	1	**5**	X		**N**
Demand-Side Control & Management	1	2	X		**Y**
Distributed Generation (DG)	3	3	X		**Y**
Load Shedding	2	4	X		**N**
Load Shifting from D-Sub to D-Sub	2	4	X		**N**

Exhibit 4-2: Assessment Summary

Commentaries for each are included in the sub-sections below.

4.1 Automation and Systems Integration Technologies… Available and Being Deployed

Monitoring for real-time ratings and better control schemes allow system operators to systems at higher load levels. Concepts proven in telecommunications, computing, and the Internet are combining with ideas from the electric power industry to present options impossible or too expensive only 10 years ago. Exhibit 4-3 below illustrates this conversion of multiple technologies.

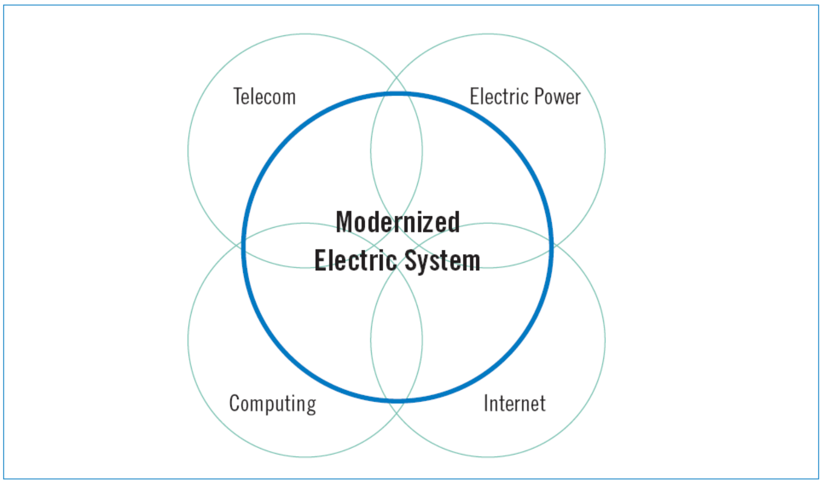


Exhibit 4-3: Convergence of Technologies from Multiple Industries

Today's power system consists of islands of proprietary technology and conflicting protocols. This often results in higher prices, custom engineering, and the need for "translation" services. Standards are not a panacea, but they do give utilities a greater choice of vendors and migration paths. For these reasons, momentum is growing to adopt open standards like IEC 61850. Already, Ethernet and Internet protocols serve as universal communications languages.

4.2 Automation and Systems Integration Technologies… To Watch

Optimal solutions for increased reliability and power quality will require automation and system integration technology improvements. Sophisticated control systems will require use of both advanced and conventional sensor technology to realize the potential benefits.

Self-healing methodologies coupled with adaptive protection systems will maximize system availability following critical contingencies. Advanced low-cost sensors linked to GPS systems will provide the basis for self-healing to system operators.

Database integration software and intelligent algorithms will translate condition data from remote monitoring and diagnostic systems into useful information, and will recommend corrective actions. Some will be automatic without operator intervention; some will require operator action to deploy. Sophisticated current signature algorithms will make incipient fault detection a practical reality.

4.3 Transmission Technologies… To Watch

Most of today's transmission systems were not designed to be electrical superhighways to deliver large amounts of power over long distances, or to support the expanding number of competitive wholesale transactions. Between 1999 and 2000, transmission congestion (as measured by NERC) grew more than 200 percent. This trend continues today.[2]

The transmission system originally was built to deliver power from a generator across town where power was distributed to the loads. Today, the transmission system is being used to deliver power across states or entire regions. As market forces increasingly determine the location of generation sources, the transmission grid must play an even more important role in an environment for which it was not designed. In addition, a lack of transmission investment over the last 30 years has led to high congestion levels in some areas, with congestion-related costs on the rise.

In response to these system pressures, transmission capacity is being constrained in several regions of the country. In some instances, demands for power among power suppliers and marketers exceed available capacity, raising questions about the system's ability to support the development of competitive markets while satisfying high reliability targets. Options to improve include building new facilities, upgrading existing ones, or modifying operating guidelines. Congestion levels make it difficult to schedule circuit outages for routine upgrades. To complicate matters even more, utilities cannot risk turning off the power to install a new service for system stability and/or overloading reasons.

The combination of aging infrastructure, increased congestion, and lack of significant capacity expansion requires careful prioritization of maintenance and construction projects, which must be coupled with asset management programs. An asset management program quantifies the risks of not doing the work as a means of setting priorities. As the assets age, this combination of engineering, experience, and business risk becomes more important.

[2] Transmission Loading Relief Procedure Logs, North American Electric Reliability Council, May 2001

The expansion of the transmission network in the U.S. will be very difficult at best if the first choice continues to be adding overhead lines. Issues of ROW availability, aesthetics, and licensing concerns make siting new lines difficult. New approaches to expansion will be required.

More underground solutions will be chosen. With time, superconducting cable is expected to become a viable option. Superconducting cable has the potential of eliminating the need for voltage transformation equipment. Imagine the possibilities if entire substations could be eliminated. Active pilot projects are underway in the Midwest and elsewhere to advance the state of this technology. As an example, National Grid is installing short superconducting lines to solve problems and gain real-world experience. In spite of great advances, commercial deployment likely fits into the 5-to-10 year horizon. High implementation costs are a concern.

Lightweight, high-temperature overhead conductors represents another technology likely to make inroads in the next 5 years. These conductors offer line upgrade options without the need for significant tower modifications.

The deployment of static var compensators for voltage and reactive control offers near-term solutions to system stability problems and relieves generators of MVAR requirements, allowing them to produce higher MW outputs.

Solid-state equipment will continue to evolve over a 5-to-10 year horizon and will offer ways to further relieving transmission congestion problems without the need to build new lines.

Innovation must take a leading role in providing solutions, and it will be important for regulators to encourage the use of these new technologies.[3] Since most will cost more than traditional solutions, there will be increasing pressures on capital investment dollars. It will be important to ensure appropriate cost-recovery measures are in place to address this issue.

4.4 Distribution Automation and Advanced Metering Initiatives… To Watch

In recent years, new technology has been implemented to automate meter reading, provide more sophisticated system controls, and automatically digitize maps.

The Outage Task Force Final Report for the August 2003 blackout found “insufficient reactive power was an issue in the blackout, but it was not a cause in itself” and recommended strengthening reactive power

[3] “The Future Beckons” by Christopher Root, IEEE Power & Energy Magazine, January/February 2006

in all NERC regions. Development of better policy and standards for providing reactive support is cited a high priority.

Shunt FACTS devices such as SVCs or static compensators (STATCOM) can be used to provide significant improvements in voltage control and stability for both distribution and transmission systems. Shunt FACTS devices have been successfully applied at voltages ranging from 35kV to facilitate the retirement of uneconomic generation assets or generators that cannot economically meet new emission standards by providing dynamic VAR control. SVCs and STATCOMs can be applied to minimize the need for “reliability must-run” generators (RMR) and the associated high annual RMR costs.

The U.S. Energy Policy Act of 2005 encouraged states to investigate advanced meters and time-of-use rates as a way to trim peak loads, leading to rolling brownouts and higher rates. Although it stops short of requiring states to install the systems, the legislation will likely accelerate a movement towards advanced meters. It will also encourage the development of data management software.

Advanced meters measure power use and report via phone, Internet, or wireless. They can remotely monitor power usage, monitor power quality, voltage, theft, and remotely connect/disconnect service. Successful deployment is largely dependent on sensor and communication technologies. Communication systems must be in place to transmit and process data. That same data may then be interfaced with grid planning and design software or enterprise software for customer information, energy management and direct load control. The “last gasp” loss-of-power signal from advanced meters can substantially improve outage management and outage restoration process. The advanced metering communications infrastructure can also be designed to support distribution automation and distribution equipment condition monitoring.

While the thrust of this report is about “Smart Grid” technologies on the T&D system and the role of the RTO with respect to those technologies, it is worth commenting here on the integration of Advanced Metering and Home Automation initiatives with Smart Grid. Around North America, there are a number of state and provincial initiatives to spur the deployment of Advanced Metering, usually driven by a desire to enable real time or hourly variable pricing to consumers. Advanced meters are those capable of two way communications at sufficient bandwidth to allow limited information transfer to the meter such as pricing and which can compute and store usage on a sub-hourly interval, as well as serve as a gateway of energy information to devices within the consumer premises.

Most AMI schemes require a high upfront investment in communications to support the meters. One widely touted technology today is “broadband over power line or BPL” which uses the distribution system to carry high bandwidth signals (Internet) to consumer premises. The signal injection/reception or head end equipment and the bypass/trap equipment required to get past distribution transformers represent a heavy cost.

Generally speaking, unless there is a state mandate to deploy real time pricing, AMI cannot be cost justified by a utility in terms of operating economics if only to automate manual meter reads. However, significant additional benefits can be realized by integrating smart devices on the distribution system with the BPL or other communications network and using these devices to improve reliability and power quality as well as to improve planning, maintenance, and general productivity. These benefits are elaborated on in Appendix H along with possible RTO responses.

There are different industry models around the world for the value chain around AMI. For instance, in the UK the energy retailer provides the meter at the customer premises and is responsible for reading it. Retailers are therefore motivated to develop and offer enhanced capabilities, in theory, and would be a logical value chain element for "smart house" technologies. But incorporation of AMI with Smart Grid applications is not encouraged by this model, nor is utility based deployment of technology such as BPL unless the utility can also sell communications to the consumer.

In North America, the model has been that the energy delivery company provides the meter and is responsible for reading it. Utilities have been the vehicle for deploying BPL or other AMI communications. In this model, it is not clear how a competitive retailer can offer real time pricing information and smart house integration through the meter since the regulated utility (who is also the provider of last resort and the regulated provider) "owns" the meter and communications. As this conundrum plays out, there could be a role for an ISO like entity to ensure equal communications. Furthermore, certain standards, business practices and methods are needed to facilitate regional implementation of demand side programs. An ISO is a natural entity to establish, maintain and offer such standards and methods. Utilities large and small, as well as retailers and other energy suppliers, can benefit from established business practices and standardized services offered by the ISO, including certification, tools, tariff, and services.

Successful and broad-base deployment of market-based demand-side programs, e.g., participation in ancillary service markets, require certain level of integration and harmonization (at least initially) of the capabilities of market participants with those of the ISO. As many utilities are evaluating costs and benefits of AMI technologies and assessing impact of time-of-use tariff for residential customers, it is an opportune time for the ISO to advance a broad vision that integrates residential smart metering as well as demand response capabilities at customer premise with energy market operations while addressing challenges and requirements at the utility level. The ISO can establish reference models, deployment scenarios, functional and technical requirements, as well as settlements procedures and Performa tariff that can be used by utilities in planning, business analysis and deployment of AMI systems. Furthermore, The ISO can offer standardized services that can bring the economy of scale benefits to small and large market participants.

Conceptual Illustration of AMI Enabled Demand-Side Market Operation

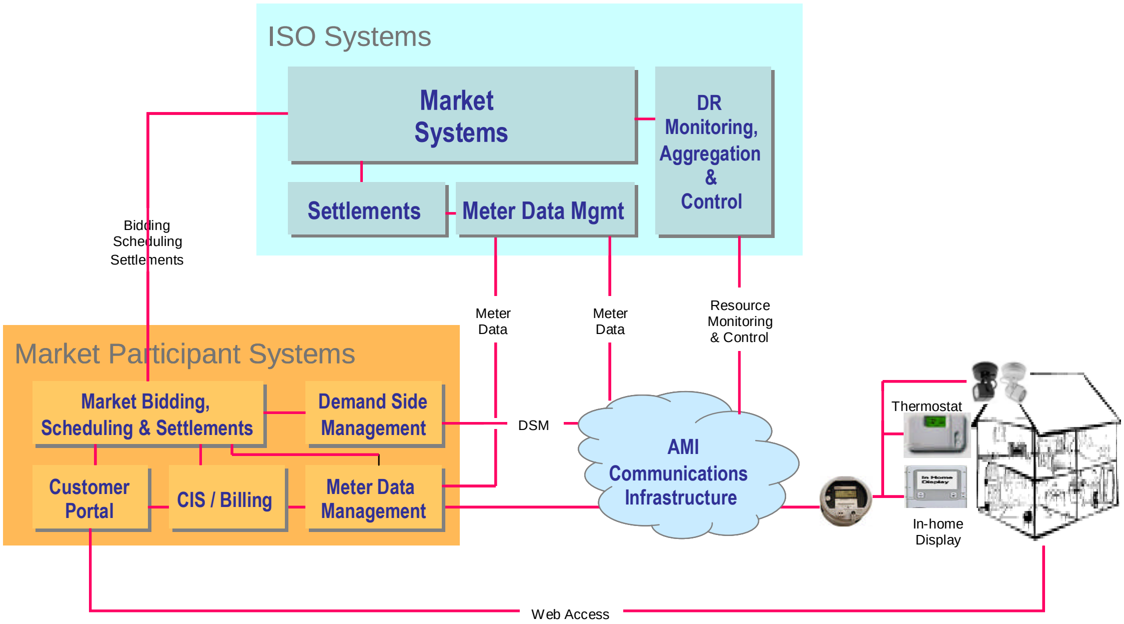


Figure 4.3 AMI and ISO enabled Market-Based Demand Side Programs

Advanced sensors and monitors measure current and voltage in real-time, enabling immediate notification of problems. Equipment and system health monitoring is a rapidly growing segment of the technology charge. Sensors and software allow monitoring of real-time line capacities.

Distribution automation means remotely monitoring and controlling operations down the line as well as at the substation. Sectionalizing and restoration schemes play major roles in reducing SAIDI and SAIFI minutes and improving overall system reliability. Integral to improved system operation is voltage VAR control using advanced switching technologies with conventional capacitor banks, SVCs, or STATCOMs, depending on the load served and respective performance requirements. Controlling voltage and VARs also offers a great opportunity to reduce operating costs by leveling voltage profiles along distribution lines, reducing line losses, reducing the need for peaking generation.

Automation can be an effective way to quickly isolate faulted line segments and physically locate the faults. This reduces the time it takes crews to find and repair the faulted segments, speeds up restoration times, reduces outage minutes, and improves overall system reliability.

Even though transmission and distribution automation are typically handled by separate departments, they both use the same basic technologies to plan upgrades. On the transmission side, next-generation control center tools are an emerging area. Grid automation is closely coupled with grid monitoring. One cannot be effectively deployed without the other. Grid monitoring uses advanced meters and software to remotely monitor transformers, circuit breakers, feeders, switches, protection equipment, capacitor banks, etc.

4.5 Distributed Generation (DG)

Working with standards bodies such as IEEE, the National Renewable Energy Laboratory (NREL) has made great strides in creating "plug and play" standards for connecting small, distributed generation to the grid.

Distributed generation can be a major strategy component to improve service reliability and power quality while minimizing capital investments. For some applications, DG may be a cost-effective way to defer basic distribution investments by bringing the generation closer to the load. DG is one way to deliver just-in-time capacity to resolve shortfalls while minimizing the initial capital investment.

DG can be most effectively used to satisfy two types of needs: 1) to supplement the grid 2) to address localized reliability or power quality concerns. For example, DTE Energy was able to use DG to prevent rolling blackouts from overloaded circuits. Most of their DG applications were on distribution circuits.[4] EPRI and DTE Energy published a report, "Best Practices Guidebook for Integration of Distributed Energy Resources into Utility System Planning I (product ID 1011250)," that contains key lessons learned, capital budget planning, financial calculations, protection, system design, siting and approval, construction, and methods of control and operation. Included are five case studies.

4.6 Demand Response and Demand Management

Demand-Side control and Management (DSM) allows a utility to control energy use by delegating control to the user in exchange for disconnection privileges during peak load periods. In return, the user receives a financial "reward" for the inconvenience.

Successful DSM requires monitoring and communications systems be in place, and that all parties have been fully trained. The mutual goal is to manage energy savings such that both parties are better off financially than without the program.

[4] DTE Energy Considers Distributed Generation" by Haukur Asgeirsson et al, T&D World Magazine, September 2006

PJM could provide a value-added service to its members by offering a centralized process for executing DSM strategies. Funding to support the program could be from membership "dues" allocated for this purpose.

4.7 Environmental Restrictions: Especially Carbon Caps and Trading

The advent of more stringent environmental restrictions, especially Carbon Caps and Trading, will complicate ISO market operations and scheduling. While current thinking looks at the highly successful sulfur dioxide caps and trading as a model for Carbon, one has to be aware that the SOX restrictions acted to encourage utilities to install scrubbers without reducing power plant output. An aggressive carbon reduction scheme may well result in reductions in annual capacity in aggregate of coal fired units until mitigating technologies are available.

Because the carbon permits are likely to be constructed on an annual basis the potential exists for coal fired (and other fossil) units in aggregate to "run out" of sufficient permits prematurely in the calendar year. This would pose reliability and market problems, which could range from irritating to very serious. The potential also exists for fleet operators to use carbon permits so as to "game" the electric markets.

Therefore, leaving the problem of having sufficient carbon certificates completely up to the plant operators may well be an inadvisable path for electric markets to follow. The industry's experience with the evolution of electric markets provides ample evidence that initial market designs frequently overlook problems in market behavior until it is too late.

Appendix H is a white paper on the state of play today in carbon caps and trading. It also attempts to identify the reliability and market integrity problems posed by carbon restrictions and propose a number of paths that the ISO markets could take in interacting with the carbon markets and permits. These are initial thoughts and by no means the final words on the subject – they are intended to get reliability and market interested parties thinking about the subject proactively. The real conclusion on this subject is that the ISO probably needs to develop a more sophisticated viewpoint on the problems and possible solutions. Armed with that, the ISO can then begin articulating the issues to policy makers in time to influence matters as things take shape.

5. Obstacles to U.S. Transmission Deployment and/or Exploitation of New Technologies

The move to a Smart Grid or Grid of the Future is inevitable in the long-term. In the short-term, however, it can be delayed by regulatory, customer, financial, and technical barriers. This section addresses the technical barriers.

Since the electric power system is the largest and most complex machine ever built, it should be no surprise that long-term perspectives are essential for developing and maintaining designs that can last 50 years or more. In recent years, industry leaders have taken a short-term approach, reacting to regulatory pressures, financial targets, and performance issues. This has created barriers that include attracting power engineers, right-of-way acquisition (licensing) concerns, and deployment concerns for new technologies due to higher costs and security issues. A brief commentary on each is given in the sub-sections below.

Not all emerging technologies have been proven in the field under real-life system conditions. A barrier to deployment then becomes utility acceptances. The issue is made worse by many utilities having a "not investigated or invented here" syndrome, refusing to accept test results unless performed on their own systems.

There is also an overriding hurdle that can delay deployment – the need to "fix a moving train." As mentioned in an earlier section, utilities are reluctant to turn off power to install upgrades. They must make changeovers with minimal service interruptions. Similar challenges exist in telecomm, airlines, and retailing industries. Their solution was to run parallel systems until the new ones could be fully installed and tested. Unfortunately, this isn't always practical or possible on the power system, especially if loadings are high.

5.1 Availability of Qualified Engineers

The availability of qualified power system engineers is a concern to many in the industry. A 2003 EPRI poll of utility executives estimated 50% of the technical workforce will retire in the next 5-10 years. This is a humbling statistic considering the number of universities offering power-engineering programs has decreased. Some, such as Rensselaer Polytechnic Institute, no longer have separate power system engineering departments. IEEE estimates the number of power system engineering graduates has dropped from 2000 per year in the 1980s to 500 today. Overall, the number of engineering graduates dropped 50% in the last 15 years.[5]

[5] "The Future Beckons" by Christopher Root, IEEE Power & Energy Magazine, January/February 2006

The power industry hasn't done the best job of selling itself. Headlines tend to advertise negative issues such as rate increases, power outages, and community relations issues related to a proposed new generation plant or transmission line. The industry has also become a victim of its own success by delivering electricity so reliably that the general public takes for granted the power will always be on.

It is unclear how the availability of technical expertise will affect the reliability of electric service, but the potential link is strong. A shortage of experienced technical staff can delay infrastructure projects and negatively impact reliability, cost, safety, and productivity.

There is a critical need to maintain our aging and highly loaded power system. The technical complexities of integrating new, electronic-based technology are growing and require sophisticated skills. The day-to-day technical workload is also increasing as construction and maintenance projects mount.

5.2 Licensing Concerns

The difficulty in securing rights-of-ways (ROWs) due to licensing issues are well know and can be significant barriers to technology deployment. However, technology can be used as a way to maximize the use of existing ROWs and hence can also serve as a deployment enabler.

Licensing concerns include non-ROW issues such as bandwidth availability to deploy new communications systems. Traditional 900 MHz frequencies are crowded. Higher GHz frequencies characteristic of Ethernet radios will have to be more fully utilized to meet high-density information stream communications requirements.

5.3 Higher Cost of New Technologies

Comprehensive cost-benefit methodologies will be needed to systematically prioritize and integrate new technologies with old. The relatively higher first-costs can be used as reasons "not to implement" even though total life cycle costs are less.

Project selection must identify common elements of costs and benefits along with special conditions such as high risk wind zones (which leads to higher probabilities for storm damage on overhead facilities, thereby favoring conversion to underground). Other considerations include urban versus rural environments, dense vegetation versus low vegetation, high load growth versus low, etc.

A representative process to prioritize projects is given in Exhibit 6-1.

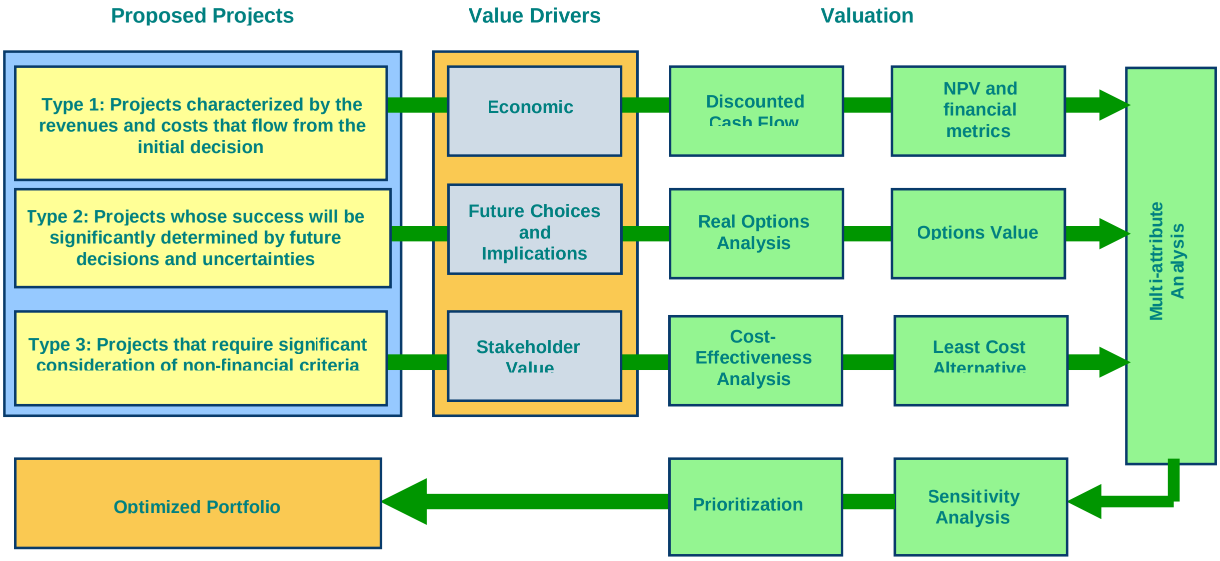


Exhibit 5-1: Representative Process to Prioritize Projects According to Cost-Benefits

5.4 Security Concerns

The vulnerability of the power system is not mainly relegated to the power system or bulk power supply; cyber security is an increasing threat as automation systems with a range of communication mediums from hard wire to wireless. Almost every economic and social function is based in some way on electricity, telecommunications, and transportation. A large-scale attack on these infrastructures would be devastating.

There are three (3) general kinds of threats with respect to the power system:

1) ***Attacks ON the Power System*** – Here, the target is the physical system. For example, simultaneous attacks on two substations or key transmission towers could cause a blackout is a large area of the grid. Cyber security would be a threat since failure of the communications system or misuse of the system could cause significant outages or system mis-operations.

2) ***Attacks BY the Power System*** – Terrorists could use installations in the power system to attack the population at large. For example, using power plant cooling towers to disperse chemical or biological agents.

3) ***Attacks THROUGH the Power System*** – Terrorists use installations to attack civil infrastructure. For example, terrorists could induce an electromagnetic pulse on the grid to damage computers or telecommunication equipment.

Only the first threat will be addressed here. Following September 11, 2001, many initiatives were put in place to protect power system security. Organizations taking lead roles in these efforts include EPRI, DOE, DOD, FERC, NERC, and NIPC (National Infrastructure Protection Center). The resulting security guidelines are compendiums of commonly accepted best practices.

Documented cases of SCADA cyber security breaches prove the threat is real. There are no documented cases of hackers breaking into the power grid, but all recognize the distinct possibility. The Tsunami of all security breaches would be if hackers penetrated control systems of the power system, natural gas pipelines, nuclear plants, water systems, and refineries all at the same time. A hacker could be a terrorist, a disgruntled employee, or a teenager determined to get back at society.

Some security companies have found important bugs in the systems used by utility companies. Driving close a substation, using a wireless LAN card and notebook PC, they connected to the power system in less than five minutes because the system was not adequately password protected. After some minutes, they were able to map every piece of equipment in the control network and talk to the business enterprise software.

PJM could serve as a storehouse for security standards on behalf of the membership. To a certain extent, this is probably happening now. But a refocused, more aggressive look at potential security gaps may be in order.

6. How T&D Utilities Can Benefit From Automation

A number of utilities are actively engaged in Smart Grid technologies. A few examples follow:

- AEP is investigating a variety of concepts including premium power parks and new methods for reactive power and voltage control. They participate in many joint programs, including GridWise, GridApp, and EPRI initiatives.

- Consolidated Edison is working on fast simulation modeling, advanced metering, and demand response among other technologies.

- Southern California Edison is working on the Distribution Circuit of the Future program, with prototypes already being deployed.

- We Energies is leading the Distribution Vision 2010 program (DV2010) intended to design and build new distribution configurations that can support high-availability, premium power office parks.

- Excel Energy partnered with major vendors on a Utility of the Future program, incorporating grid monitoring, outage detection, and other cutting edge applications.

- BPA and TVA continue to proactively test and implement Smart Grid technologies.

IOUs buy on overall value. Cost is a factor, but buying decisions are often driven by total cost of ownership, ROI analysis, or asset return models. IOU's technology choices are strongly influenced by regulation – either mandates that force compliance, or policies that limit when they can expect rate relief. IOUs hesitate on technology purchases if it is unclear whether regulators will allow them to recover the investment in their rates. New technology must integrate with existing systems.

Publicly owned utilities and municipals are driven by customer concerns. If rates are high, the emphasis is on lowering costs. If reliability is poor, the emphasis is on improving service. Technology to support operational efficiency is key to either goal.

PJM can provide on-going benefits to its membership by offering prescriptive prioritizing methods that can be customized as needed, that focus on maximizing the use of transmission facilities, tracking and monitoring power usage, and coordinating responses to outage events.

6.1 Improved Reliability

It is well known that outage minutes can be reduced and reliability improved by judicious sectionalizing of the transmission and distribution systems. Traditionally, for transmission it meant networks and for distribution it meant radial lines. Transmission protection included high-speed tripping (less than 5 cycles from detection to open) using pilot protection. Distribution protection meant relays and breakers at the substation, and fuses, switches, and reclosers down the line.

Automation has opened the door of almost endless possibilities for protection schemes and configurations. Premium power parks are now possible at the distribution level by applying networked topology to critical feeders. This makes automatic two-source feeds possible, depending upon substation capacity. End-users are relieved of the need to install local backup generation because the expectation is that power will always be on unless there is a fault on their bus or in their facility. Fault clearing is done in less than 5 cycles by reclosers detecting a fault is between them and instantaneously and simultaneously opening.

Improved sensor, communication, and data collection technology helps to pinpoint the faulted segment, reducing crew deployment and repair time, saving even more outage minutes through faster restoration.

Restoration strategies in general can be much more sophisticated with automation present, limited only by the equipment installed and communication available. What cannot be handled automatically with local schemes can be passed to the SCADA system for action by system operators. A significant concern and industry challenge is to allow automatic reconfiguration after fault clearing to minimize customer interruption, but also to avoid overloading circuits in the process.

Microprocessor relays serve as protection control devices and data collectors. The more data we have on the system, the more intelligent we can become in operating it. If sensors and switches monitor voltage and VARs and operate capacitor banks everywhere in the system to minimize VAR production from generating units, the more efficient the system will be. Generators will be allowed maximize sellable MW output. Leveling voltage profiles and bringing power factors close to unity, means fewer losses and avoided costs from having to generate more to make up for the losses.

As the power system gets smarter and smarter through automation, the more options we have to optimize overall performance. If data collection includes health monitoring, we can proactively respond to equipment replacement needs and avoid reactionary measures as the first option.

6.2 Lower Congestion Charges

Automation can be used to optimize the power routing on both transmission and distribution lines. In spite of what we do, electricity will always follow the path of least resistance from the generator to the load. Wholesale power transactions and bulk power transfers to maximize the use of low cost generation without regard to line loadings results in line overloads and power bottlenecks.

Most of today's transmission systems were not designed to be electrical superhighways to deliver large amounts of power over long distances or to support the expanding number of competitive wholesale transactions. Transmission congestion has grown multiple times since the year 2000, and continues to be a problem today.

Microprocessor relays, PMUs, real-time state estimators, other communications-based equipment, local and wide-area communications networks, and SCADA systems can be used to optimize power flows and minimize congestion. This can defer the cost of line additions and the cost of generator additions, which extends the timeframe for capital additions.

Reducing congestion also means paying less for energy wasted in serving line losses. However, if the objective functions becomes reducing line losses and maximizing reliability when planning energy flows, this runs counter to competitive wholesale trading where low-cost generation from many miles away is preferred over the generator next door if energy from the far-away generator costs less.

6.3 Comprehensive System Monitoring Capabilities

Health monitoring is limited only by the number and quality of sensors collecting data, the sophistication of the data processing software, and equipment to act on the findings. This is true for a transformer, breaker, or any other piece of monitored equipment. It is also true of the power system. The more "eyes, ears, voices, and muscles" available to act, the more sophisticated system operation can be. The more information available to the system operator, the better job he or she can do optimizing system operation. The more that can be done automatically through automation, the less information that has to be passed back to SCADA.

Proactive maintenance leads to planned outages, which always minimizes customer outage minutes and improves system reliability. Proactive maintenance is possible with adequate monitoring equipment.

A popular monitoring technology at the transmission level is Phasor Measurement Units (PMUs). PMUs can proactively identify potential system stability problems by identifying phase angle differences in time for system operators to take action before islanding occurs.

6.4 Lower Operating Costs

Techniques for lowering operating costs were discussed in previous sections. More general and greatly abbreviated comments will be made here.

Automation simply put is collecting data and doing something with it. Deploying data collection equipment and making on-going improvements to data management software allows utility companies to lower operating costs by more fully utilizing existing assets, making better use of system operator time, deploying more sophisticated automatic restoration schemes, better utilizing repair crews, and avoiding financial and political penalties from missed reliability targets. Automation can also be used to avoid system separation, islanding, and collapse. Avoided costs by way of this scenario can be very large.

7. How ISOs/RTOs/Market Operators Can Benefit From T&D Automation… Examples

Automation, including monitoring, communications, and control as well as automatic devices, can benefit ISO/RTO operations by improving system visibility, providing the possibility of additional control schemes, improving operations via better information for decision making and analysis, and can provide more robust mechanisms for "blackout prevention" or response to extreme disturbances. Automation can also act to align ISO activities more closely with those of their TO partners.

The major categories of visibility, improved operations, and new control schemes each offer benefits to the broad ISO business objective of market operations, system operations, reliability, and planning. The "ISO Opportunity Matrix" in Appendix B provides considerable detail about particular ISO business goals in each of those areas, and about particular automation strategies within each broad category. Each intersection of a strategy with an objective that can exploit it is explained in brief.

Improved visibility clearly benefits operations – limits can be more closely approached with confidence, for instance – and thus benefits reliability simply because system operations is improved. Accounting for improved visibility in the calculations can benefit adequacy calculations and system planning. Closer adherence to limits also benefits market operations and reduces congestion. Beyond these obvious benefits there can be surprising but important benefits in terms of improved settlements, reduced Unaccounted for energy, and so on.

Improved operations can also entail a reduction in unplanned outages, in cancelled outages due to other unplanned or extended outages, with attendant benefits to congestion and capacity/reserve costs. Unplanned outages can be reduced via better asset condition monitoring or by better/faster post fault analysis which allows faster restoration of outaged equipment, as examples.

New control schemes include VAR dispatch of generation and VAR control of T&D assets. In the 1980's vertically integrated utilities often pursued VAR dispatch as a means of reducing losses. However, with the advent of deregulation and a focus on market operations, this objective was lost. Studies at the time often showed a potential savings of 5% of losses – not a trivial amount. VAR dispatch, by improving power factor, can also allow more lines loaded close to the MVA limits so that TTC can be more closely utilized. In a market environment, this not only reduces losses but also can improve interface limits and reduce congestion. When generator VAR dispatch is linked to generator output curves and MW are traded for MVAR, the true meaning of MVAR support as an ancillary becomes clear and enhancements to ISO markets are possible.

Other control schemes can include feeder load shedding and load shifting as responses to system or local capacity shortages. These act to improve reliability but also could be used to reduce peak prices, LMP prices, and capacity costs – and longer term, as tools to use in enhancing capacity margins.

Market Operations are benefited in a number of ways. Improved visibility allows closer adherence to limits and more aggressive limit setting – which act to reduce energy costs via imports as well as to reduce congestion. As well as such gross effects, there are likely improvements in settlements via reduced UFE, reduced losses, and better allocation of losses that can be achieved with MWH metering at more and lower granularity points.

New protection and disturbance reaction schemes such as wide area protection and intelligent islanding can be deployed to improve system response to major disturbances. These can be classed as "blackout prevention" schemes which act to increase reliability. To the extent that they are deployed and prove useful, they may in time enable systems to operate more closely to limits and to set limits more aggressively. This is particularly true of RTOs operating in a region where stability limits are as important as thermal limits.

Finally, condition monitoring of assets allows improved asset management. This can improve reliability and reduce both capex and O&M costs for the TO.

Appendix B identifies over 90 potential ways that 21 different automation tactical objectives can benefit ISO business goals.

8. How ISOs/Market Operators are Affected by Industry Developments

The thrust of this report is "Industry Needs and How PJM Can Respond" in terms of changes in industry environment and technology and how PJM can exploit technology to respond. However, there are three major changes in industry environment that will *require* responses from PJM to ensure the integrity of its market and system operations, as well as creating opportunities for PJM to respond in ways that positively facilitate industry response to these changes.

The first change is arguably upon us today – a proliferation of renewables and distributed generation. Much has already been said elsewhere about the day-to-day reliability of these resources and the difficulties they pose in market operations and scheduling. Coupled with possible changes in fossil plant availability due to aging and to cost pressures on plant operators, the somewhat random behavior of renewables will pose challenges to ISO operations – it is also the case that today ensuring capacity adequacy even in "shoulder" months is challenging as scheduled outages tend to collect there.

Another factor is the ongoing and perhaps increasing focus on plant operator's day-ahead and short-term outages as a possible mechanism to manipulate the market.

All this suggests that new mechanisms in scheduling plant outages, approving outages, and sanctioning unscheduled outages will be called for. And definitive market mechanisms for allocating the costs of variable availability on renewable generation operators will have to be established. A "white paper" is attached to this report as Appendix G which outlines possible market mechanisms for allocating outage schedules.

The second change, demand side markets, is arguably imminent in the 3-5 year time frame. California has mandated Time of Use (TOU) Pricing and Advanced metering Initiatives (AMI) and other states (Texas, New York) are exploring it aggressively. In all cases the purpose is to enable the creation of demand side markets as a way of mitigating peak prices and capacity costs. A coalition of Mid-Atlantic public utility commissions is investigating the same issue.

In all cases, the utilities bear the onus of analyzing the costs and the technical feasibility and of performing cost – benefit analyses which include the advantages AMI can bring to distribution engineering, reliability, and operations. The PUCs and other parties employ economists to estimate the market price benefits of TOU pricing. However, one element that has been overlooked is the impact of TOU pricing and AMI on ISO settlements and wholesale revenue metering. In many cases wholesale revenue metering and the definition of take out points were established as a matter of convenience incorporating existing revenue meters and stations where utilities had adequate metering. There is good reason to believe that TOU and AMI will require upgrades to the wholesale metering system, perhaps bringing take out point definition to lower levels – even feeder level – and significant changes to ISO settlements processes and systems. A second white paper on this topic is attached as Appendix H.

When the goal of one day settlements and clearing as a way of improving market efficiencies and encouraging retail competition via lower capital requirements is considered, it is not hard to see that upgraded wholesale metering and ISO settlements are an important adjunct to TOU pricing and AMI.

The third change could be 3 years or 10 years away, depending upon one's view on the politics of global warming. However, in the event that carbon emissions caps and trading come to the United States, there will be major impacts on the energy markets. While it is possible to put the entire onus of having adequate carbon emission rights upon the plant operators, there are major capacity adequacy and reliability issues attached to the timing of the usage of those rights. It may be that the ISO will have to take some role in ensuring that near the expiry of annual emissions rights there will not be major capacity shortfalls due to premature rights usage – leaving demand in the final months beyond what renewables, hydro, and nuclear can supply. The problem is complicated by the fact that other industries will come under carbon controls so that the energy industry cannot "solve" the problem in a vacuum. Appendix I is a third white paper on the roles the ISO could take in incorporating physical carbon emissions tracking and physical rights markets into today's SCUC and LMP solutions.

Appendix A: Technical Opportunity Matrix

A.1 Assessment Summary

SUMMARY	Low-1	High-5	Deployment		PJM Added Value
Technology	**Cost**	**Benefits**	**5 Yrs**	**10 Yrs**	**Y or No**
Automation and System Integration					
Advanced Sensors	2	3	X		**Y**
Advanced Monitoring	3	**5**	X		**Y**
Advanced Communications:					
- Wireless	2	**5**	X		**Y**
- Broadband over PowerLine Carrier (BPL)	1	4		X	**Y**
- Ethernet over Fiber	**5**	4	X		**Y**
Data Concentrators	1	3	X		**Y**
Interconnected Comm's Infrastructure:					
- Wide Area Networks (WANs)	2	**5**	X		**Y**
- Local Area Networks (LANs)	2	**5**	X		**Y**
- Home Area Networks (HANs)	4	3		X	**Y**
Digital Protection	3	**5**	X		**Y**
Phasor Measurement Units (PMUs)	2	**5**	X		**Y**
Transmission					
Advanced Switchgear & Controls	2	3			**N**
FACTS Devices:					
- Static VAR Compensators (SVCs)	**5**	4	X		**Y**
- Static Compensators (STATCOMS)	**5**	4	X		**Y**
- Thyristor-Controlled Series Caps (TCSCs)	2	4	X		**Y**
- Advanced HVDC	**5**	2		X	**N**
Advanced Power System Stabilizers (PSSs)	1	**5**	X		**N**
Light Weight, High Temp OH Conductors	3	**5**	X		**N**
Superconducting Cable	**5**	**5**		X	**Y**
Distribution					
Volt/VAR Control	1	**5**	X		**N**
Demand-Side Control & Management	1	2	X		**Y**
Distributed Generation (DG)	3	3	X		**Y**
Load Shedding	2	4	X		**N**
Load Shifting from D-Sub to D-Sub	2	4	X		**N**

A.2 Assessment

		Value to Industry							Low-1	High-5	Deployment	
Technology	**T or D**	**Operation**	**Reliability**	**Performance**	**Asset Management**	**Critical Success Factors**	**PJM Added Value**	**Steps to Achieve**	**Cost**	**Benefits**	**5 Yrs**	**10 Yrs**
Automation and System Integration												
Advanced Sensors	T, D	Adaptive Conformance to Equipment Ratings	More Sophisticated Sectionalizing Possible	More Complete Operator Alarms	Condition Monitoring	Microprocessor-based controls capable of reading and translating sensor signals (typically low signal strength)	Source for Technology Recommendations and Integration Support	Catalog Existing and Imminent Technologies along with Lessons Learned	2	3	X	
		Dynamic Load Support	More Outage Management Options	More Complete Real-Time System Status	Makes PBR Possible	Control software written to process sensor information	Special Interest Group to Influence Standards for the Benefit of the Membership	Form PJM-Based Sensor Resource Team for use by the Membership				
		Highly Accurate Metering	More Effective Crew Management	Eliminates Saturation Issues	Sensors are More Full Range, Meaning Fewer Types Needed, Simplifying Stocking Requirements	Noninvasive Applications		Develop Standards and Deployment Recommendations				
			More Sophisticated Protection			Low Cost Compared to Conventional Alternatives						
			Tighter Coordination Margins					Publish Standards and Deployment Recommendations				
			Faster Fault Location									
Advanced Monitoring	T, D	Automatic Disturbance Reporting Gives Operators Information Early Enough to Take Proactive Actions	Automatic Archiving of Fault & Load Data Facilitates Event RCA and Long-Term Corrective Actions	Sophisticated System Condition Reporting Possible	Condition Monitoring Data Allows Full Utilization of Existing Assets and Proactive Replacement Strategies	Software resident in local devices as well as SCADA user interface designed to process captured information	Standardized Data Management Guidelines that Consolidates Lessons Learned from Members and Industry	Catalog Existing and Imminent Technologies along with Lessons Learned	3	5	X	
					Automatic Integration with Maintenance Systems	Operator Training	Centralized Storehouse for Spare Equipment reduces Inventory Requirements for Members	Form PJM-Based Advanced Monitoring Resource Team for use by the Membership				
					Automatic Integration with Scheduling Systems	Sensor Deployment		Develop Standards and Deployment Recommendations				
					Failure Prediction Allows Scheduled Outages instead of Unplanned Outages	Integration of System Monitoring with Customer-Side Monitoring		Publish Standards and Deployment Recommendations				
Advanced Communications:	T, D											
- Wireless		Security	Makes Automation Practical	60% Speed of Ethernet + Fiber	No Wires to Install	Communications Infrastructure	Source for Technology Recommendations and Integration Support	Catalog Existing and Imminent Technologies along with Lessons Learned	2	5	X	
- Broadband over PowerLine Carrier (BPL)		Good for Normal Operation Data	Off if Line Out of Service	High Speed Data Transfer	Uses Existing Power Lines	Resident Communications Expertise	Training Resource		1	4		X
- Ethernet over Fiber			Makes 5-Cycle Clear Possible	Offers Highest Speed Data Transfer	Expensive to Install	On-Call Vendor Support	Centralized Communications Experts On Call 24/7	Form PJM-Based Communications Resource Team to work in conjunction with Network Team for use by the Membership	5	4	X	
Data Concentrators	D	Ties System to SCADA	Facilitates Substation Data Collection and More Sophisticated Automation Schemes	Multi-Function Operation Reduces Equipment Requirements	Multi-Vendor Interface Support Reduces Equipment Requirements	Seemlessly Integration with Multi-Vendor Controls	Source for Technology Recommendations and Integration Support	Catalog Existing and Imminent Technologies along with Lessons Learned	1	3	X	
						On-Call Vendor Support						
Interconnected Comm's Infrastructure:	T, D											
- Wide Area Networks (WANs)	T, D	Automatic w/o Operator Intervention	Links Subs to SCADA	Reduces Data Congestion	Dynamic Load Balancing	Communications Infrastructure	Source for Technology Recommendations and Integration Support	Catalog Existing and Imminent Technologies along with Lessons Learned	2	5	X	
- Local Area Networks (LANs)	D	Automatic w/o Operator Intervention	Links to SCADA	Reduces Data Congestion	Dynamic Feeder Balancing	Resident Communications/Software Expertise			2	5	X	
- Home Area Networks (HANs)	D	Automatic w/o Operator Intervention	Links to Subs	Slow Speed Data Collection	Dynamic Load Management	On-Call Vendor Support	Centralized Network Experts On Call 24/7	Form PJM-Based Network Resource Team to work in conjunction with Communications Team for use by the Membership	4	3		X
Digital Protection	T, D	Operates on Input Data Points Rather than TCC's Making Custom Logic Schemes Possible	More Sophisticated Sectionalizing Schemes	Multi-Functional Device Allows More Sophisticated System	Multi-Functional Device Reduces Number of Relays to Perform same Functions	Micro-Processor Based Controls and Communications Infrastructure	Systematic Approach to Replacing Legacy Electromechanical Equipment with Latest Micro-Processor Based Technonoly		3	5	X	
		TCC's Become Fail-Safe Backup Mode	Lowers SAIDI, SAIFI, CAIDI, MAIFI		Doubles as Sensor	Ability to Integrate Multi-Vendor Controls	Training Resource	Create Curriculum, Course Materials, and Schedule				
						Protection Engineers Must Be On Board to Fully Utilize Capabilities of Technology						
Phasor Measurement Units (PMUs)	T	Anticipates System Stability Problems; Alerts System Operators	Prevents Unexpected Outages; Lowers SAIDI	Monitors Threshold System Phase Angles to Allow Proactive Response to Potential Performance Problems	Makes Higher Intersystem Loadings Possible	Location of PMUs at Points Critical to Intersystem Operation	Can Initiate System-Wide Deployment Guidelines to Minimize Intersystem Oscillations and Maximize Asset Utilization	Form Working Group to Evaluate Existing and Imminent Technologies	2	5	X	
						Communications Infrastructure		Develop Standards and Deployment Recommendations				
						On-Call Vendor Support		Publish Standards and Deployment Recommendations				
Transmission												
Advanced Switchgear & Controls	T	Allows Interconnection of DG to Grid Because of High-Speed Switching Without Operator Intervention	High-Speed Switching Means Faster Fault Isolation and Improved Reliability	Better and Faster Sectionalizing means Faster Fault Clearing, Faster Restoration, and Improved Reliability	Redispatching of Load from Overloaded to Underloaded Circuits means Better Utilization of Circuits Capacities	Communication Infrastructure	No Added Value	n/a	2	3	X	
			High-Speed Switching and Controls									
FACTS Devices:		Increases Power System Control		Increases Power Transfer Limits Across the System								
- Static VAR Compensators (SVCs)	T	No Impact on System Operator Unless SVC is Off; Removes Need for Operator Action Following a Major Disturbance (and Possible operator Error)	Prevents Outages Due To Voltage Dips	Local and/or System Voltage and VAR Support can Relieve Line Loadings by Localizing VAR Supply; Improves System Dynamic Performance	Reducing Flow-Through VARs Lowers Line Losses and Increases MW Transfer Capacity	Available Lower Cost Generation Sources; Transmission Capacity Available for Reroutes	Reduce "Reliability Must Run" (RMR) Generation Costs through Redispatch to Lower-Cost Units with Potential Cost Savings in the $100M Range		5	4	X	
- Static Compensators (STATCOMS)	T	No Impact on System Operator Unless SVC is Off; Removes Need for Operator Action Following a Major Disturbance (and Possible operator Error)	Prevents Outages Due To Voltage Dips	Local and/or System Voltage and VAR Support can Relieve Line Loadings by Localizing VAR Supply; Improves System Dynamic Performance	Reducing Flow-Through VARs Lowers Line Losses and Increases MW Transfer Capacity	Available Lower Cost Generation Sources; Transmission Capacity Available for Reroutes	Reduce "Reliability Must Run" (RMR) Generation Costs through Redispatch to Lower-Cost Units with Potential Cost Savings in the $100M Range		5	4	X	
- Thyristor-Controlled Series Caps (TCSCs)	T	No Impact on System Operator Unless TCSC is Off	Can Prevent Outages Due to Line Overloads; Mitigates Subsynchronous Resonance (SSR)	Allows Higher Power Transfers; Prevents SSR due to Series Caps; Increases Stability Margins; Regulates Power Flows Between Parallel Transmission Lines	Export Power Longer Distances by Lowering Effective line Losses	Identifying System "Weak" Points Where In-Line Impedance Reduction Can Provide Congestion Relief	Use Intersystem Transfer Improvements to Maximize Use of Most Economic Generation; Use Polle Savings to Fund Capital Improvements		2	4	X	
- Advanced HVDC	T	Sophisticated System to Operate	Can Prevent Outages Due to Line Overloads; Firewall Against Cascading Outages	Insensitive to Phase Angle Differences; Interconnections Can Be Made Between Two Asynchronous Systems for More Economic or Reliable Operation; Relieve Intersystem Power Transfer	On-Going Maintenance may Increase Operating Costs; Can Bring Low-Cost Generation from Long Distances; Generation Can Be Located Closer to Fuel Supply to Reduce Transportation and	Must be intersystem transmission application. Backp-to-back HVDC links not justifiable. **Application may be limited in PJM system because of relatively short transmission lines.**	No Added Value	n/a	5	2		X
Advanced Power System Stabilizers (PSSs)	T	Makes Life Easier for System Operators	Prevents Outages Due to Loss of Generation from System Stability Issues	Fast-Acting PSSs Prevent Generator Overspeed During System Events and Separation of System Generators	Higher Intersystem Transfers Possible, Maximizing the Use of Existing Generation	Endorsement by Member Utilities.	No Added Value	n/a	1	5	X	
Light Weight, High Temp OH Conductors	T	System Operators Have More Flexibility in Balancing Load Due to Higher Thresholds	Reduces Sag as Line Loadings Increase, Resulting in Fewer Outages from Contact with Vegetation and Structures, thereby Improving Reliability	Able to Carry Higher Capacities during Emergency Conditions without Violating Sag Thresholds	Higher Loading Capacity per Mile means Higher Asset Utilization per Mile	Start with New Construction or Conductor Replacement Due to Repair Requirements; Must be Spec Reuirement in New Operatiosn and Planning Standards	No Added Value	n/a	3	5	X	
Superconducting Cable	T	No Impact on System Operator	Impact Could Be to Improve Reliability By Providing More Load Switching and Overload Prevention Options	More Robust System Performance Through Better Mitigation of Overloaded Circuits	Has the Potential for Selectively Eliminating Substations	Endorsement by Member Utilities; Infrastructure that can Supoort Maintenance Requirements	High Initial Cost and unknown (but perceiced high) maintenance costs may need endoresement from PJM to succeed. Potential value is very high.	Establish Steering Committee to develop implementation strategy for PJM system. Include T & D pilot installations to demonstrate value.	5	5		X
					Voltage Transformation From Generator May Not Be Necessary, Eliminating Associated Equipment Costs							
					Can Increase Capacity Limits With Existing ROWs							
Distribution												
Volt/VAR Control	D	Can Be Used to Redirect Power	Prevents Outages Due To Voltage Dips	Supports System Voltage	Saves Money by Reducing Line Losses	Better Handled at Individual Member Level	No Added Value	n/a	1	5	X	
		Operators Can Use Local VAR Support Instead to Minimize Exchanging Billable Generation (MW) for VAR Support	Voltage Support Results in an Inherently More Stable System with Fewer Outages	Has Potential of Relieving VAR Shortage Issues at Transmission Level	Provides Opportunity for Lowering Substation Voltages Thereby Saving Operating Costs							
Demand-Side Control & Management	D	User actively controls energy use, including amount, time of day, and peak. DSM is totally under user control.	Energy efficiency programs reduce energy use without affecting service quality/reliability. Peak load reduction programs reduce loads during peak power consumption to avoid outages from circuit overloads.	Variable demand contracts require discipline in how energy is used (or not used) during times of peak pricing.	Successful DSM requires knowing what has been used, and modifying usage to minimize energy costs.	DSM is currently in use by member utiltiies. They must see a value in modifying existing practices. Goal is to manage energy savings to be significantly greater than DSM spending, resulting in a significant net financial gain.	Offer more centralized process for executing DSM strategies and resulting energy savings over investment costs.	Initiate pay-back incentive system based on a tiered-goals approach. Funding to come from membership "dues" allocated for this purpose.	1	2	X	
Distributed Generation (DG)	D	Complicates System Operation Due To Protection and Safety Concerns	Offers Localized Supply Options and Associated Switching Options to Prevent Outages and/or Reduce Restoration Time	Complicates System Operation Due To Protection and Safety Concerns	Distributed Generation Allows More Localized Options for Meeting Demand Requirements	Must Have Effective DG Integration Strategy	PJM can serve as a catalyst to develop and implement broad-based DG integration strategies on behalf of the membership.	Form Working Group to research and summarize available technologies; critique successful case studies.	3	3	X	
		Relieves T & D Congestion Issues		Offers Localized Power Quality Improvement Solutions	Increases Protection Costs	Need to Match DG Technology to Application; e.g., Need Consistent Wind Areas to Apply Wind Turbines		Wriet broad-based integration strategies and implementation guidelines for use by the membership. Reference IEEE 1547.				
					Reduces Congestion Costs by Reducing High-Loss Line Miles							
					More Local to Load Means Less Circuit Miles							
					Can Reduce the Need for Peaking Generation							
Load Shedding	D	Sophisticated Protection Schemes Makes Load-Shedding More Selective and Less Dependent on Operator Actions	Prevents Wide-Spread Cascading Outages	Offers Load Balancing Under Adverse System Conditions	Reconfiguration after Load Shedding can prevent line overloads until more long-term line loading strategy can be developed.	Better Handled at Individual Member Level	No Added Value	n/a	2	4	X	
Load Shifting from D-Sub to D-Sub	D	Requires Operator Intervention	Prevents Outages Due to Overloads	Relieves Congestion Issues	Maximizes Capacities of Existing Substations and Feeders	Better Handled at Individual Member Level	No Added Value	n/a	2	4	X	

Appendix B: ISO Automation Benefits Matrix

Automation/Integration Tactics

Automation Benefits that Can Be Realized by an ISO

Contents:

Enable More Accurate State Estimation

IEDs integrated into SCADA will help state estimation in several ways: more and more redundant data; in many cases more accurate data (eliminate transducer bias for instance); improved data reliability as RTU failures become less of an issue.

Better Short-Term Visibility

Improved state estimation will automatically result in better short-term visibility. State estimation will be able to "penetrate" to lower voltage levels; will be more accurate; and will be more reliable.

Reduce Unexpected Same Hour Congestion

Better state estimation (and visibility in general) should reduce unexpected congestion due to a "perception" of the dispatch that a limit is being violated/approached when it is not telemetered - the estimator will have a value for that branch which may (or, perversely could affect things the other way) allow more accurate approach to the limit. That is, limits which are not in fact being approached will not become limiting in congestion.

Decrease TRM – Closer Adherence to Limits

Better short-term visibility from state estimation will allow operator confidence in operating closer to actual equipment limits.

Improve Support for Audits

Better state estimation enables higher confidence by market participants in the validity of the model. If the ISO state estimator model is made available to the local TOs, they can compare their results with ISO. This can help find potential problems and improve accuracy.

Lower Risk Exposure to Loss of Load

Better awareness should provide better anticipation of system vulnerabilities (and more accurate contingency analysis) and better operator visibility of conditions during disturbances; thus improving reliability even if only intangibly.

Improve Security – Contingency

More accurate state estimation provides a more accurate basis for real-time contingency analysis.

Improve Security – Operating Reserves

More precision in the state estimator can allow lower margins.

Provide Visibility of Feeder Loads

Visibility of feeder loads will enable the ISO to take bus load forecasting to a finer level of granularity and obtain more accuracy. This in turn will improve state estimation and provide better operational visibility in support of load reduction and other schemes.

More Accurate Settlements

By having telemetered feeder MW the integration of telemetered data can be used as a cross check against revenue meters to correct losses calculations as well as to catch erroneous MWH revenue meter data.

Better Short-Term Visibility

Visibility of feeder loads will enable the ISO to take state estimation to lower voltage levels, monitor subtransmission and the impact of load switching on the transmission system, to better forecast bus loads, and to better implement load reduction and voltage reduction schemes.

Better Short-Term Load forecasting

Better bus load forecast and correlation of feeder level loads with weather will allow improved load forecasting over time. (Note: Overall peak load forecasting may not improve but bus load forecasting and hourly load forecasts should improve.)

Improve Long-Term Load Forecasting

Long-term load forecasting can take advantage of feeder load data on an hourly basis to achieve not only peak forecasting but a better understanding of how load shapes (hourly loads) will evolve over time.

Provide Phasor Measurements

IEDs can provide Phasor Measurements with the addition of satellite time synchronization. The EIPP project has demonstrated a number of benefits of Phasor Measurement Unit (PMU) implementation.

Some type of Phasor measurement may be required in the future for regulatory compliance.

Better Short-Term Visibility

PMUs will improve state estimation redundancy and convergence. They may also provide the opportunity, if enough are deployed, to do "direct state estimation" without iterations and thus enable scan rate state estimation to be provided.

Lower Risk of Exposure to Loss of Load

PMUs and the visibility they provide of dynamic system disturbances should enable operators/computers to take remedial actions before disturbances propagate (i.e., blackout prevention).

Improve Protection Coordination

PMUs can be used in Wide Area Protection schemes.

Implement Monitoring of System Dynamics

Many systems have poor understanding of system dynamics and limited ability to validate transient and dynamic stability studies as swing data on a millisecond basis is only available from fault recorders. The ability to capture swing information on all transients will allow improved stability models/validation and thus better understanding and analysis of system dynamics.

Better Short-Term Visibility

Visibility of system swings is essential to understanding system dynamics.

Decrease TRM – Closer Adherence to Limits

To the extent that TRM settings reflect stability limits the ability to better understand what the stability limits are (perhaps as a function of system condition and loadings) will allow more confidence in setting limits and approaching them operationally.

Lower Risk Exposure to Loss of Load

Better understanding of system dynamics can lead to improved wide area protection schemes and thus increased reliability.

Improve Security – Contingency

Understanding system dynamics should allow a better understanding of which contingencies will cascade into multiple contingencies and under what conditions. This in turn will enable improved contingency limit settings.

Provide Post Fault Non-Operational Data Access

Integration of IEDs with non-operational data retrieval, storage, and access will enable TO and ISO staff to investigate faults remotely and determine in many cases if restoration is safe without the need for staff to physically go to the station(s) and examine relay targets. This will reduce outage times post fault.

Better Short-Term Visibility

Access to fault data will allow ISO staff to understand outage causes and the need for any reactive operational actions.

Fewer (Shorter) Unplanned/Emergency Outages

Access to more post fault information will allow better analysis of root causes and the development of remedial actions with the TOs which should over time result in fewer outages.

Fewer Cancelled Outages

Access to post fault data, if used as described above to reduce unplanned outages and shorten planned outage times, will result in fewer cancelled outages due to other unplanned outages interfering.

Lower Risk Exposure to Loss of Load

Improved Reliability as described above should ultimately lead to lower loss of load exposure.

TO Better Informed of Equipment Condition

Access to post fault data will allow the TO to better understand issues like accumulated through fault currents or breaker operating times/contact conditions, which leads to better condition assessment. This in turn leads to CBM and lower O&M costs as well as improved reliability.

Implement Dynamic Equipment Rating

IED data can be used to calculate and implement dynamic ratings on transmission facilities. Factors that can be taken into account include:

- Local ambient conditions – Real-time condition of the equipment (i.e., transformer temperature, line sag).
- Facilities can be temporarily subject to overload conditions if equipment conditions can be closely monitored.
- Ratings can be derated under some conditions as well to allow equipment to remain in service that might otherwise be taken out of service.

Lower Congestion Costs/Uplift

Dynamic equipment ratings should allow the ISO to impose higher ratings at some times and under some conditions (power transformers, less margin of safety with regard to line sag, conceivably adaptation to short circuit ratings and configuration) which should reduce congestion costs as the higher ratings are utilized.

Decrease TRM – Closer Adherence to Limits

Better monitoring (accuracy, reliability, penetration of monitoring) should allow the ISO to operate closer to limits; decreasing TRM margins and therefore helping with congestion. Also, anything that helps the ISO react to contingencies and relieve overloads faster will decrease the TRM requirement. This could include load shedding, temporary overloading of other facilities, switching, and other measures.

Less Same Hour Unexpected Congestion

IED integration can help improve the accuracy of network models. This should theoretically improve the accuracy of predicted congestion. (In the ideal world, congested facilities should end up operating right at the limits that congestion SCUC was set to respect.)

Improved Adequacy – Day-Ahead

If Day-Ahead operational planning is using conservative limits based on seasonal maximum temperatures, for instance, then by considering dynamic ratings in the day-ahead limit setting constraints may be relaxed on imports or on some generations based on congestion.

Lower Risk Exposure to Loss of Load

Any operation of facilities in an overload condition or under questionable equipment conditions will be more secure if careful monitoring is possible. This should decrease the risk of outages and give operators more time to make assessments before taking drastic action.

Lower Cost of Reliability – Planning – Deferred Investments

Dynamic ratings should increase equipment utilization and allow operation at higher loadings at peak under some ambient conditions. This could conceivably allow for slight deferrals of investment. Note, however, that peak temperatures co-incident with peak load for protracted periods of time probably act to eliminate this benefit.

Improve Security – Contingency

If dynamic ratings allow temporary overloads then this additional "transmission capacity" can be utilized post contingency for periods of time during which re-dispatch or other measures are taken. Increasing contingency limits will have a direct effect on security as well as congestion costs.

Provide Better/Faster Fault and Disturbance Analysis

Integration of IEDs with non-operational data retrieval, storage, and access will enable TO and ISO staff to investigate faults remotely and determine in many cases if restoration is safe without the need for staff to physically go to the station(s) and examine relay targets. This will reduce outage times post fault.

Beyond faster fault analysis by access to remote data (see post fault data access), the ISO should be able to do a better job of analyzing faults when multiple TOs are involved or when additional data from IEDs can be used to better get a handle on the cause, location, and severity of a fault.

Fewer/Shorter Unplanned Outages

Access to fault data should allow TO and ISO staffs to better understand the causes of outages and develop remedial measures over time, thus improving reliability.

Fewer Cancelled Outages

Improved Reliability via use of Fault data in analysis should result in fewer outages cancelled because of unplanned/extended outages.

Intelligent Fault Restoration

Determining the cause of a fault quickly and accurately provides confidence that the restoration plan will not have any unintended consequences.

Improve Protection Coordination

Better fault analysis allows better limit setting and understanding and easier validation/confirmation of relay settings.

Provide Better Network Models

IEDs and better network monitoring leading to better state estimation can enable the state estimator to be used to identify and correct (with manual effort, usually) errors in the network models – impedances and the like, as well as occasional status errors. The network models are central to dispatch, security analysis, and affect most reliability and market operations.

Reduce Unaccounted for Energy

At many ISOs, losses are computed by network analysis calculations and allocated to supply schedules. The difference between generation and load revenue meters will not necessarily equal the load calculations - the delta is called "Unaccounted for Energy" and is also allocated. However, large UFE is a symptom of poor metering and/or poor loss calculations which in turn can be attributed to errors in network models.

More Accurate Settlements

Improved loss calculations and reduced UFE will improve settlements as less energy is arbitrarily (and erroneously) allocated.

Provide Better Forecasting

Better visibility of feeder load data will ultimately enable better bus load forecasting – better overall forecasts (although temperature forecast accuracy is more critical overall) and better allocation of peak load forecasts to bus loads, as well as to improved load shapes.

Reduce Peak Pricing

Fewer unexpected peaks or load shape deviations lead to reduced peak prices in the hour-ahead market due to day-ahead under-forecasts in the day-ahead markets.

Fewer Deviations from Schedules

When hour-ahead markets are forced to react to unexpected peaks, the hour-ahead or balancing market sufficiency may be limited. Base load units may end up deviating from schedule to compensate, or if the balancing market is too heavily utilized, some units may have trouble keeping up with schedules.

Better Short-Term Load Forecasting

Same objective as the automation benefit.

Provide Better Day-Ahead Interface Limits

Use of post fault analysis and wide area protection schemes leading to better dynamic models and analysis should allow interface limits to be set more precisely according to system conditions.

Stabilize Peak Pricing

The ability to utilize interfaces better to import power should result in lower peak prices at times, especially those due to insufficient internal capacity.

Lower Congestion Costs/Uplift

Greater interface imports will reduce congestion costs in some regions.

Lower Capacity Costs

The ability to count on higher imports will reduce internal capacity requirements and thus reduce capacity costs.

Decrease TRM – Closer Adherence to Interface Limits

TRM is the amount of transmission reserve below nominal interface limits that must be maintained. If the interface limits are more accurately calculated then they can be approached more closely.

Increase TTC

If the interface limits can be more accurately calculated and utilized, then total transmission capacity may be increased.

Improve Security – Contingency

Contingency limits should increase under some conditions if increased imports can be used to remediate contingency loadings or loss of generation.

Improve Security – Operating Reserves

If increased imports become an operating tool or if operating reserves can be acquired from external sources with confidence then internal lowered operating reserves are more acceptable.

Provide More Granular Delivered MW Data

Installation of IEDs at lower voltage substations (down to feeder breaker level) will allow collection of MW and MWH data at lower level take out points, thus allowing more granular congestion analysis.

Lower Congestion Costs/Uplift

More granular data (bus load forecast, etc.) should allow more precise congestion calculations and may result in lower congestion costs, overall (slight).

Reduce Unaccounted for Energy

If an ISO today does not have an account for UFE it instead considers it as part of losses. If it does have UFE, this represents an imprecision in dispatch and settlements. Either way, it is a metric of error in the system and creates difficulties with participants if too large. Precision of lower voltage level load data will allow more precise computation of losses and will allow visibility of UFE so that it can be systematically attacked.

Reduce Electrical Losses

Bringing settlements MW data to lower and more granular levels will reduce UFE and will enable a reconciliation of metered (generation less load) with calculated losses. Knowing losses accurately is the key to taking measures such as VAR dispatch which reduce losses. Precision of lower voltage level load data will allow more precise computation of losses and will allow loss reduction to be implemented and verified.

More Accurate Settlements

Identification of UFE and more precise load data will allow settlements to be at a more granular level and will reduce settlement inaccuracies.

Better Short-Term Load Forecasting

More granular load data allows improved bus load forecasting, as the decomposition of feeder load into conforming and non-conforming and analysis of temperature/hour sensitivities can occur at lower levels with less inaccuracies.

Implement VAR Dispatch - Generation

Availability of better system data, especially lower voltage level voltages and loads, and integration of IEDs at generator substations plus integration of generator reactive control (excitation set point) either manually or automatically will allow real-time VAR dispatch.

Reduce Electrical Losses

Studies performed in the early days of Optimal Power flow showed that 5% reduction in total transmission system losses was not unrealistic. This required accurate bus load forecasting, including knowledge of load power factors and the ability to identify and control those transmission/generation reactive controls that impacted losses the most. These would include LTCs where available and generator excitation.

Decrease TRM – Closer Adherence to Limits

VAR dispatch enables improvement of the power factor of congested branches. This means that TRM due to poor power factor can be reduced, if it is an issue.

Increase TTC

VAR dispatch can improve power factor and reduce MVA while increasing MW flows. This increases nominal TTC for MW flows, especially if the power factor expected when calculating TTC did not take into account optimal VAR dispatch.

Increase Security – Operating Reserves

VAR dispatch can enable additional MW to be considered from some units by ensuring that power factor is not reducing capacity transfer on limiting branches.

Improve Adequacy – Day-Ahead

Reduced losses increase available capacity by the amount of total loss reduction. If transmission system losses are 5% of load and the reduction is 5% this will result in a 0.25% increase in capacity; probably not that significant overall.

Implement VAR Control - T&D

Control of T&D "VAR/Voltage" controlling devices such as capacitors, shunts, and especially LTCs enables (together with generation excitation setting) loss minimization via VAR dispatch. It also may enable slightly higher facility utilization by improving power factors on lines and transformers.

Reduce Electrical Losses

Studies in the early days of Optimal Power Flow showed that system losses could be reduced by as much as 5% via VAR dispatch.

Decrease TRM – Closer Adherence to Limits

VAR control can add to the capabilities of VAR dispatch and act to improve power factor, similarly allowing more MW flows thus closer utilization of transmission limits, without increasing MVA.

Increase TTC

To the extent that TTC calculations assume less than ideal power factor, the ability to control VARs with T&D devices can allow improved power factor and higher MW flows for the same MVA. This can be exploited to improve TTC if the TTC calculations assume VAR optimization.

Improve Security – Contingency

VAR dispatch applied with real-time network models can adapt voltage/tap settings to real-time conditions and can allow post-contingency voltage conditions to be better maintained.

Implement Feeder Automation - Load Shifting

With automation to the feeder breaker level and distribution automation allowing remote control of feeder-end disconnects, feeder loads can be shifted from one station to another. This helps the TO maintain reliability in the face of substation equipment problems, and it also may allow the ISO to move load from one take out point to another and avoid congestion costs or pocket inadequacy.

Lower Congestion Costs/Uplift

The ability to shift loads from one station to another should allow the ISO to reduce spot congestion costs by moving load out of pockets under some circumstances.

Fewer Unplanned (Emergency or Forced) Outages

The ability to shift feeder loads across stations may avoid equipment overloads or allow reduced ratings for a period of time so that outages can be scheduled and managed instead of taken on a forced basis.

Less Same Hour Unexpected Congestion

The ability to shift loads across stations and avoid outages should reduce unexpected congestion costs.

Provide Voltage Reduction Control

IEDs integrated to the TO and ISO systems will give the operations the ability to measure on a feeder basis the load reduction achieved by voltage reduction. Furthermore, control of LTCs will allow fast voltage reduction and restoration (integrated with loss minimization as well) so that it becomes an operational tool.

Stabilize Peak Pricing

Voltage Reduction as an operational tool where the ISO understands how many MW of load reduction can be realized becomes a way to shave peak demand. This will over time influence the market as generators understand that the ISO can avoid peak prices.

Lower Capacity Costs

The ability to achieve load reduction via voltage reduction gives the ISO another tool to use to reduce capacity margins required. This in turn should reduce the costs of acquired capacity margins.

Improve Adequacy – Day-Ahead

If voltage reduction and attendant load shaving can be considered as part of evaluating generation adequacy for day-ahead and planning purposes then it provides greater adequacy for the same generation.

Improve Adequacy – Planning

If voltage reduction and attendant load shaving can be considered as part of evaluating generation adequacy for day-ahead and planning purposes then it provides greater adequacy for the same generation

Improve Security – Operating Reserves

Load reduction via voltage reduction as an operational tool is another way for the ISO to respond to generation outages or load beyond capacity margins and thus becomes another kind of operating reserve.

Implement Feeder Load Shedding

Feeder Load Shed is the ability for the ISO to order targeted load shedding on a feeder basis via tripping the feeder breaker. The TO would actually implement the shedding but the ISO would have visibility of the feeder load and would know how many MW would be obtained. Load shed rotation could be performed by the TO on the basis of shedding other feeders at the same station or at other stations "co-located" to the first in terms of congestion or transmission facility loading. Load restoration could be performed by the TO under ISO instruction. The advantage of having visibility and automatic remote control to the feeder level is that (a) the TO and the ISO would know how many MW would be affected and (b) load shed and restoration could be implemented very quickly without dispatching crews to the stations. This would make restoration much easier and would reduce the customer impact of load shedding.

Stabilize Peak Pricing

While load shedding in response to peak pricing is not part of the ISO tariff today, the knowledge that the ISO can shed load effectively if need be will have a stabilizing effect on the market. Especially after a generator outage, generators will be reluctant to "gouge" with very high spot prices if they know that the ISO can decline to accept any bids and instead shed load.

Lower Congestion Costs/Uplift

Similar to the general effect the load shedding option has on market peak spot price, the ability for the ISO and the TOs to shed load selectively by location can act to dampen congestion costs.

Lower Capacity Costs

The ISO can legitimately use load shedding as a substitute for capacity reserves and reduce overall reserve requirements either as a normal practice or as a recourse during peak periods. Either way, this will have the effect of dampening market expectations for capacity prices and will enable the ISO to procure reserves more cost effectively.

More Accurate Settlements

Depending upon where the TO has defined take out points and has revenue metering installed, the deployment and integration of IEDs with revenue quality integrated readings will enable more granular and accurate settlements by moving settlements to lower voltage levels. Additionally, if the ISO is to incorporate load shedding into tariffs the ISO will need accurate reading of actual load shed – which can be obtained from IEDs with the ability to capture load before and immediately after load shedding activity.

Improve Adequacy – Day-Ahead

Load shedding as a substitute for capacity margin will similarly increase the day-ahead adequacy. Conceivably, enough load shedding could be provided for so as to provide adequacy in every load pocket and enable the deferral of considerable capacity addition.

Improve Adequacy – Planning

Load shedding should have a similar benefit in longer term adequacy for planning purposes.

Lower Risk Exposure to Loss of Load

Load shedding as a remedial action available to system operators should reduce the risk of large, uncontrolled, loss of load. Targeted load shedding to relieve critical transmission overloads could be a faster action than re-dispatch and should create the situation where shedding xx MW eliminates the risk of a larger disturbance of XXX MW lost.

Improve Security – Operating Reserves

Load shedding would allow the ISO to manage with reduced operating reserves both overall and at specific locations as load could be shed as an alternative to bringing additional generation on.

Capacity Requirements

While the ISO today cannot make the decision to plan for capacity below that required to service forecasted load, load shedding is an alternative to capacity that can be utilized in planning under scenarios where load growth outstrips available and achievable capacity, for instance, after an unplanned and extended outage of a major nuclear facility.

Implement Automated Load Restoration

Feeder Load Shed is the ability for the ISO to order targeted load shedding on a feeder basis via tripping the feeder breaker Load shed rotation could be performed by the TO on the basis of shedding other feeders at the same station or at other stations "co-located" to the first in terms of congestion or transmission facility loading. Load restoration could be performed by the TO under ISO instruction. In order for feeder load shedding and rotation to be acceptable to TO customers, restoration time Thus feeder load shedding and rotation require automated load restoration. The benefits of load restoration are therefore in tandem with feeder load shed. They are listed here for completeness – please see the section above on feeder load shedding to see the explanations.

Stabilize Peak Pricing

Lower Congestion Costs/Uplift

Lower Capacity Costs

Improve Adequacy – Day-Ahead

Improve Adequacy – Planning

Lower Risk Exposure to Loss of Load

Implement Adaptive Relaying

Adaptive Relaying is the ability to have IEDs alter relay settings and coordination schemes based on either controls from SCADA or SA systems or based on inputs directly sensed by the IED. It is also possible to imagine future implementations where the relays interchange information and alter coordination accordingly.

Improve TTC

To the extent that TTC reflects static protection settings, the ability to alter protection based on system conditions may increase the available transmission capacity under some circumstances.

Implement Intelligent Islanding and Wide Area Protection

Intelligent Islanding is the ability for the system to automatically island itself or parts of the system for general or localized insufficiencies and in so doing avoid widespread outages. It can only be implemented if it is fast (thus automatic) and done in adaptive ways based on observed insufficiencies and or frequency change. Wide area protection is a broader capability which can also be used as a way to mitigate stability problems. In this case, the protection has to operate under autonomous but widely coordinated control w/o instruction from the EMS.

Decreased TRM – Closer Adherence to Limits

Schedules may be accepted/developed which fully exploit limits if there is no worry about peak loads or other real-time variations causing local insufficiencies which cannot be controlled. Stability limits are often done with nomographs and thus are never reflective fully of real-time conditions. As such, they are inherently conservative. Operations can be less conservative in adhering to these limits if the operators know that islanding or wide area protection will act to "catch" a major disturbance before loss of load becomes widespread.

Increased TTC

If islanding and wide area protection allows the system to withstand second contingencies without loss of load, then TTC can be increased (assuming that islanding is an acceptable alternative to redispatch). Historically, there have been cases where such an operational tactic was allowed in light of very high costs of maintaining local reserves.

Reduced Exposure to Loss of Load

These advanced protection schemes provide protection against low probability – high impact events (3rd contingencies, etc.) and thus reduce the probability of widespread outages.

Develop Corrective Strategies for Disturbances

Visibility of system dynamics and analysis of fault data may allow the ISO to develop corrective strategies that can be rapidly applied during disturbances (islanding, example) as alternatives to less informed actions which shed more load.

Lower Risk Exposure to Loss of Load

Strategies to remediate disturbances or react more precisely will result in less load loss/shed as a result.

Increase TTC Based on Interface Limit Settings

Corrective strategies developed in response to major disturbances that threaten interconnections may result in increased interface limit settings as confidence builds in the system's ability to withstand the disturbance and maintain interfaces.

Implement Condition Based Maintenance and Inspection

Use of IEDs to monitor equipment condition for warning signs of degraded asset physical condition (transformer monitors of different types, monitoring accumulated through fault current, monitoring breaker closing time and contact condition, etc.) allows inspection to occur not on a periodic (annual) basis but as indicated. It thus leads to actual maintenance being performed as needed rather than on a quasi periodic basis as a result of periodic inspection. This normally results in reduced O&M costs to the TO. It also results in improved equipment reliability/availability as the continuous monitoring will enable the TO to avoid catastrophic/major failures and instead perform remedial maintenance or planned replacement.

Fewer Unplanned (Emergency or Forced) Outages

Early indication of equipment failure allows life ending/catastrophic failure to be avoided and instead planned replacement/maintenance to be performed. This reduces unplanned outages.

Fewer/Shorter Planned Outages

Because outages are performed only when equipment condition warrants, there should be a reduction in planned outages and the planned outages should be better planned around required inspection/work, shortening the outages. The likelihood that an outage detects additional problems needing unplanned work and outage extension is reduced.

Fewer Cancelled Outages

The reduction in unplanned outages/outage extensions will result in fewer cancelled outages due to unplanned outages that preclude the scheduled ones. This problem grows in shoulder months as all outage work is scheduled in a compressed time period so the benefit is potentially real.

To be Better Informed of Equipment Condition

Condition monitoring and the provision of condition data will enable the TO to better assess and know equipment condition. This links to many operational and asset management opportunities for the TO (see TO opportunity matrix).

[ISO Opportunity Matrix]

[Help on Matrix]	Market							Operations											Reliability							Planning					
ISO Business Objectives / **Automation/Integration Tactics**	Stabilize Peak Pricing	Lower Congestion costs / Uplift	Lower Capacity Costs	Reduce Unaccounted for Energy	Reduce Electrical Losses	More Accurate Settlements	Deviations from Schedule	Better short term visibility	Better short term load forecasting	Fewer Unplanned (Emergency or Forced) Outages	Fewer/Shorter Planned Outages	Fewer Cancelled Outages	Same Day Maintenance Approvals	closer adherence to limits	Less same hour unexpected congestion	Improve Support for Audits	Increased TTC	Intelligent Fault Restoration	Improve Adequacy - Day Ahead	Improve Adequacy - Planning	Lower Risk Exposure to Loss of Load	Lower Cost of Reliability - Planning - Deferred Investments	Improve Security-Contingency	Improve Security - Operating Reserves	TO Better Informed of Equipment Condition	Improve Long Term Load Forecasting	Capacity Requirements	Improve Transmission Expansion Planning	Increase TTC Based on Interface Limit Settings	Improve Protection Coordination	Improve Seasonal Planning
Visibility / Awareness																															
[Enable More Accurate State Estimation]								X						X	X	X					X		X	X							
[Provide Visibility of Feeder Loads]						X		X	X																	X					
[Provide Phasor Measurements]								X													X									X	
[Implement Monitoring of System Dynamics]								X						X							X		X								
[Post Fault Non-Operational Data Access]								X		X		X	X								X				X						
Improved Operations																															
[Implement Dynamic Equipment Rating]		X												X	X				X		X	X	X								
[Better/Faster Fault and Disturbance Analysis]										X		X	X					X												X	
[Provide Better Network Models]				X		X																									
[Provide Better Forecasting]	X						X		X																						
[Provide Better Day Ahead Interface Limits]	X	X	X											X			X						X	X							
[Provide More Granular Delivered MW Data]		X		X	X	X			X																						
New Control / Dispatch Options																															
[Implement VAR Dispatch - Generation]					X									X			X		X					X							
[Implement VAR Control - T&D]					X									X			X						X								
[Implement Feeder Automation - Load Shifting]		X								X					X																
[Provide Voltage Reduction Control]	X		X																X	X				X							
[Implement Feeder Load Shedding]	X	X	X			X													X	X	X			X			X				
[Implement Automated Load Restoration]	X	X	X																X	X	X										
[Implement Adaptive Relaying]																	X														
Blackout Avoidance																															
[Implement Intelligent Islanding]														X			X				X										
[Implement Wide Area Protection Schemes]														X			X				X										
[Develop Corrective Strategies for Disturbances]																					X								X		
Link to TO Opportunities																															
[Implement Condition Based Maintenance and Inspection]										X	X	X													X						

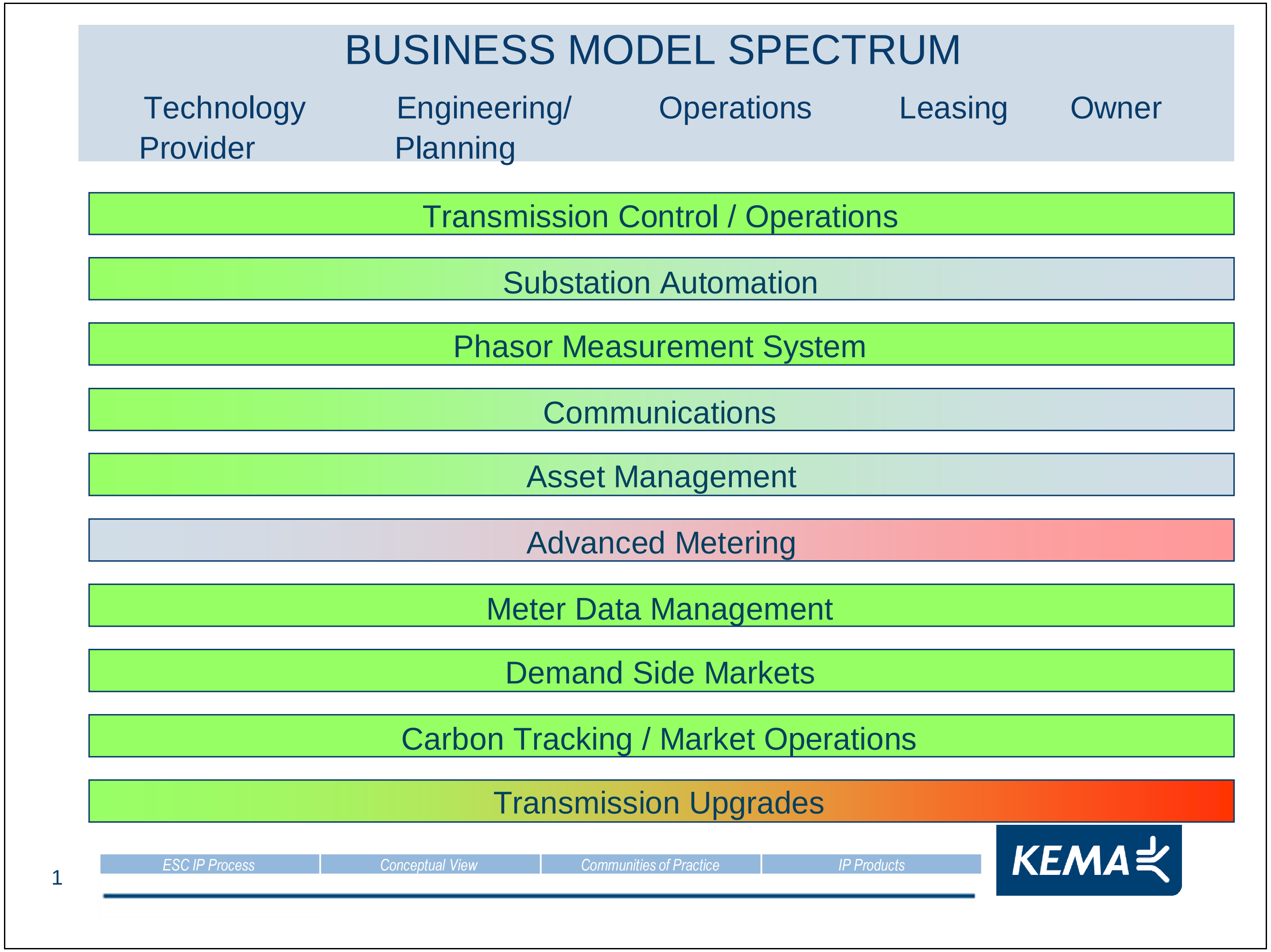
Appendix C: Industry Needs and RTO Responses

Scenario for Industry Environment	Industry Need	Solutions RTO can Provide	Technology Development, Competitors/Partners	Triggers	RTO Strengths	Challenges	Developmental Actions RTO Can Consider
Utilities' finances are compressed by rate freezes and focus on distribution reliability reduces funding for transmission operations. Or, rate relief is accompanied by load growth and PBR rates which have the same effect on transmission funding. Lack of regional perspectives on funding aggravates this. An aging workforce adds to the difficulties facing transmission operations, engineering, and maintenance.	Mechanisms to reduce the adoption time and cost of new technologies via standardization, group supply management, utilization of common technical resources, and consolidation of appropriate activities.	Facilitation of standards and needs assessment; leadership in group efforts including engineering, design, and procurement; source of common resources; outsourced operations and ownership.			Technical Competence and "Brand" especially around real-time IT systems and data management; system operations. Ability to "see" regional costs and benefits. Possible ability to harvest regional benefits and to finance technologies.	Resistance of utilities to see RTO "move into" what had been their domain. Need to establish different financing and recovery models, possibly including risk capital investment and for-profit activities.	One concept that applies to all needs is that if RTO can create a case for providing services/facilities to utilities as part of the ISO tariff it has enabled utilities to move capex and opex costs from their T&D cost structure to the ISO tariff which appears as part of an energy charge. Not all services are suitable for this model.
Transmission Control Centers are a Cost center that does not "improve" or "benefit" T&D utility financials, and is under increasing pressure from NERC reliability standards. Retirements and personnel reductions add to the difficulties.	*Transmission Operations Systems* • *Lower cost to build/ own* • *Adaptable technology* • *Support NERC reliability objectives* • *Lower cost to operate* • *Trained Work Force*	EPC and possible operations consolidation Regional cost savings and efficiencies in operation through reduced technology, systems, and personnel costs.	AC2 and related Vendors, consultants; possibly major transmission owners. Systems to capture, store, and mine high volume historical data for reliability audits. EMS systems of larger size as penetration goes to lower voltages.	NERC standards; utility focus on distribution	Technology Supply manager Operations competence	Winning acceptance of utility middle management. RTO exposure to liabilities of transmission switching; safety issues. Have to be offset in part by argument of greater ability to train and manage and put quality programs in effect.	Building support for and licensing AC2 technology; offering RTO services in design and development; building a case for increases quality/lower risk/lower costs from consolidation. Obtaining NERC/FERC support for outsourced transmission operations as cost reductions and reliability enhancements.
Ad hoc replacement of electromechanical components with IEDs fails to exploit the benefits of data available from IEDs and utilities lack the vision and ability to deploy them in a planned fashion.	*More rapid deployment of substation automation integrated with IT systems for engineering, maintenance, and asset management. Commonality of data models and integration technologies to facilitate applications deployment.*	Standards, supply chain management, engineering/design, systems integration, and centralized IT systems and applications	IEDs in stations, Substation Automation, Data Warehouses, Communications Outsourcers, consultants	Reliability Utility Investment Strains Asset Management Focus	Independent 3rd Party Regional Standards	New Engineering competence for RTO. Utility middle management resistance to loss of scope. Financing vehicles & ROI models.	Developing the case for regional benefits of substation automation integrated with reliability and asset management operations; developing standards and new service requirements
IEDs and SA present financial challenges due to obsolescence vs. long-term depreciation schedules for field equipment.	*Solution to the problem of financing accelerated replacement of older substation protection /control systems and avoiding lengthy depreciation schedules.*	Financing, or arranging external financing/leasing arrangements. Replacing capital investment with (lower cost) O&M expenses; possibly moving SA under ISO umbrella and into ISO tariff structure	SA as trigger Financial institutions	SA, utility investment strains, technology obsolescence	Regional Scope Independent non-regulated alternative financing and tariff structures	Depreciation schedules vs. O&M budgets, utility management, regulatory, managing financial risks	Developing a cost/benefit analysis of technology deployment and a business model to support PLM role in financing or changed tariff model
Telecoms deregulation and technology advancement offers an opportunity for utilities to consolidate and upgrade their infrastructure if they can find the capital to do so.	*Low cost high bandwidth, secure, reliable, and flexible communications backbone to support station automation and other technology initiatives*	Engineering, Provider, supply manager, operations	Fiber, wireless, broadband over power line Consultants, communications providers. Self-configuring/identifying IEDs.	SA; utility financing strains; need for Advanced Metering and Distribution Automation	Regional scope, technology competence	Separating T from D in communications infrastructure, is typically low margin business	Developing a cost benefit analysis in support of automation and other regional goals

Scenario for Industry Environment	*Industry Need*	Services RTO Can Provide	Technology Development, Competitors/Partners	Triggers	RTO Strengths	Challenges	Developmental Actions RTO can Consider
Under rate pressure, utilities cannot fund investments in Transmission facilities and lapse into reactive "fix it when it breaks" behavior. Regulators seek prescriptive solutions and utilities do not apply sophisticated asset management techniques.	*More sophisticated analytics for asset management, regulatory acceptance of risk management, coordination of asset performance data, integration of asset management, maintenance planning, and transmission outages*	IT systems to support asset management and analytics, development of analytics, centralized data warehouse and mining, application of risk management to maintenance and replacement planning	IT, analytics, condition monitors Consultants. Risk management and real options analytics appropriate to T&D assets. Analytics to exploit condition monitoring data	Reliability and harvesting congestion savings	Regional purview of congestion and understanding Independence	Liabilities if RTO actually makes asset decisions	Developing models for harvesting congestion savings to support investments and asset decisions; developing risk management methodologies; building a regulatory case for adopting models. (Note: these are automation/IT investments and O&M "investments" – not new regulated facilities.)
New Transmission technologies are available that increase capacity/reliability but individual TOs cannot justify in rate base nor support the engineering /operations infrastructure required to deploy them.	*Transmission Upgrades to Improve Capacity and Availability – Repowering, Reconductoring, FACTS, HVDC, Superconductivity, and other technologies*			Reliability Transmission ROI allowed	Regional planning role Independence Ability to identify congestion savings Ability to manage outages	ROI approval; regulatory approvals for any alternative business models.	Developing alternative business model concepts to allow 3rd party investment/ ownership of transmission facilities. Also possible ways to link congestion savings to facility investments beyond regulated rate of return models.
	Repowering – increasing voltage levels on existing ROW.	Cost/benefit; engineering; outage scheduling	Installation methods that allow line to be put in service intermittently during repowering; possible design/construction methods to allow tower re-use; compact substations to use existing footprint.	Capacity shortages and ROW resistance from localities	Regional cost benefit visibility; ability to manage outage schedules dynamically	Technology, construction planning that allows dynamic scheduling	Concept development with manufacturers and A&E firms; work processes; investigate maintenance scheduling problem
	Reconductoring – increasing ampacity on same line	Cost benefit, engineering, outage scheduling	Installation methods that allow line to be put in service intermittently during repowering; possible design/construction methods to allow tower re-use; compact substations to use existing footprint. Increased short circuit duties may pose stability concerns.	Capacity shortages and ROW resistance from localities	Regional cost benefit visibility; ability to manage outage schedules dynamically	Technology, construction planning that allows dynamic scheduling	Concept development with manufacturers and A&E firms; work processes; investigate maintenance scheduling problem
	FACTS and HVDC devices provide grid operational control not otherwise possible. Congestion can be avoided and contingency limits can be relieved.	Cost benefit, engineering, integration of control schemes with ISO operations, possible market models	New analytics to integrate device operations in market and reliability operations. New operator tools to aid in visualization and utilization	Capacity, congestion	Planning and operations; cost benefit, control design		Identifying opportunities for deploying/exploiting these devices and preliminary cost benefit analysis. Identification of mathematical developments needed. Possible market mechanisms for recovering any O&M/depreciation costs associated with use
	Superconductivity offers greater capacity for underground cables, generators, and possibly other applications	Cost benefit, engineering, understanding risks/rewards with this technology	???	Bottlenecks in selected locations amenable to cable solutions	Planning and operations; cost benefit, control design	Cost and reliability of technology	Positing requirements to manufacturers
	High speed switching and voltage control devices may improve stability and extend the knee of the voltage drop curve post contingency	Cost benefit, engineering, integration of control schemes with ISO operations, possible market models	Algorithms to analyze and operate such devices. Integration of control schemes with market and reliability operations.	Stability and voltage stability as congestion limits post contingency	Planning and operations; cost benefit, control design	Reliable wide area protection schemes and control applications	Identify need for technology and fund R&D; develop cost benefit methodology and ROI argument
Demand Management and/or Demand side Markets at Retail Level as means of mitigating rapid load growth and capacity shortages.	*Advanced Metering/Meter Data Management deployed at lower costs and integrated with demand management/markets. Faster movement through pilots to mainstream adoption.*	IT and data management; supply management, certification, development of demand management tariffs/controls	IT and Metering Systems Firms Data management technology to handle the very large prospective volumes	Demand side markets, Time of Use Rates, Advanced Metering	Independence IT competence Regional scope	Utility data ownership	Building a case for centralized meter data management; developing competence in MDM; building a case for improved demand side market models

Scenario for Industry Environment	*Industry Need*	Services RTO Can Provide	Technology Development, Competitors/Partners	Triggers	RTO Strengths	Challenges	Developmental Actions RTO can Consider
	Demand side markets that make consumer load/ time shifting attractive to high usage customers (i.e., markets that work for all participants)	Market operator	Ability to handle larger magnitudes of settlement data and calculations;	Time of Use rates, market solutions	Role as ISO market operator	Public acceptance	Developing improved demand side market models and validating them in simulations
	TOU and AMI deployment at the retail level may require upgrades to and deeper penetration of wholesale revenue metering, to maintain/improve settlement schedules and accuracies.	Own/operate wholesale revenue meters.	Ability to handle larger magnitudes of settlement data and calculations	TOU rates, market pressure for daily settlements and billing	Technology, market operations, neutrality, and financing		Analyze settlements process under TOU rates and/or demand management for process and information needs
Carbon Trading along the lines of SOX emissions trading requires physical emissions tracking and integration of emissions certificates ownership/usage with physical power production and probably with power physical markets as well.	*Environmental Physical markets; certificate tracking and tracking of certificate trading; integration with power scheduling and generation planning/ maintenance scheduling and with generation protocols such as RMR.*	Market operator for emissions physical permits, integrated emissions/energy/ maintenance scheduling, tracking of permit usage	Commodities Markets (?); analytics that manage short-term and long-term integrated emissions and power. Integration with national and/or global markets	Carbon trading Political shift in attitudes towards global warming	Role as ISO operator Ability to understand emissions/energy/capacity tradeoffs	Regulatory Technology – potentially a difficult long-term scheduling problem.	Developing concepts for emission tracking and integration with power market operations; developing necessary short to long-term complex scheduling analytics. Building awareness politically and in commodities markets of the need for physical linkages
						Conflict of interest Shared ownership with utilities Regulatory	
Load Growth and New Generation Technologies Strain Transmission Reliability and Increase Risk of Widespread Outages.	*Improved Blackout Avoidance technologies/ processes such as regional PMU networks, applications to analyze PMU data; risk management approach to reliability analysis and planning; techniques beyond "N-2" planning, more flexibility in scheduling transmission outages. IT systems capable of monitoring and analyzing larger data bases will be needed*	EPC, owner, technology developer, ongoing developments as reliability coordinator	Vendors	NERC, DOE	RCC role, technical competence, link to AC2 and SA	Utility ownership	Developing risk based analytics and analytics for exploiting PMUs. Developing a future technologies requirements vision to use in partnership with IT, EMS, and related vendors

Appendix D: Business Model Spectrum


BUSINESS MODEL SPECTRUM
Technology Provider
Engineering/ Planning
Operations
Leasing
Owner
Transmission Control / Operations
Substation Automation
Phasor Measurement System
Communications
Asset Management
Advanced Metering
Meter Data Management
Demand Side Markets
Carbon Tracking / Market Operations
Transmission Upgrades
1
ESC IP Process
Conceptual View
Communities of Practice
IP Products

Appendix E: Business Scenarios Table

	Shock Absorber	Muddlin' Thru	Market Choice & Rationality	Future Grid	Wild Card
SUMMARY					
End Point (What is the end point 'equilibrium' of the scenario?)	Adverse events occur and the regulated utility must absorb the financial shocks. Components of the system are shaped by Regulatory mandates imposed on Capacity, Reliability, Environmental, and Demand Issues. Market-based solutions are not favored. The ability of utilities to invest and for market participants and customers to make choices is reduced. Coupled with lower economic growth, higher interest rates, and continued population growth driving load, the ability of utilities to maintain and modernize the grid is compromised. Regulators react by mandating (politically) selected solutions in detail. This could have negative implications for supplier product development and innovation. Utilities accept 3rd party investment in automation and asset management. Load growth slows due to costs and economy slowing	Business as usual. Asset management is a survival tactic and demand management a reliability tool. Hand to mouth investment insufficient to slow the aging of system components. Economy remains strong and fuel prices moderate, spurring load growth. However, the regulatory environment is inflexible and moves away from market solutions. Mandated and dictated solutions are the norm as with "shock absorber", however they are tariff related and programmatic and do not divert capital resources. The limited capital spending that is possible is left to the discretion of the utilities.	Robust system with pockets of technology excellence and advancement. PUC recognition of need for "T" investment, strong load growth and political support for demand side markets, renewables, DG, TOU rates Favorable economic conditions and moderate fuel cost growth are factors in the regulatory environment continuing to embrace market-based solutions for environmental and energy issues. Regulators see the need for infrastructure and are open to specific projects. Market solutions do include PBR structures, however. Utilities are able to invest but are overwhelmed with distribution reliability, load growth, and need to support AMI and customer choice/demand markets.	Advanced technology is beginning to be deployed because local optimization gives way to grid optimization. Integration of "Smart House" technologies with "Smart Grid" and DG/renewables drives technology deployment and structural changes in the industry.	Re-regulation of generation; next blackout; next nuclear fiasco; another urban outage as Long Island City; oil shock from Mid East/Venezuela. Any dramatic negative change to the energy world will likely result in more/harsher regulation in the next decade, as opposed to more rapid development of market solutions. PBR gets harsh; regulatory mandates assumed for capacity/reliability issues.

	Shock Absorber	Muddlin' Thru	Market Choice & Rationality	Future Grid	Wild Card
Rationale (What is the story line of this scenario?)	Higher fuel costs and end of historical rate freezes lead to large energy rate increases that appear random or unjustified to customers/politicians. This overwhelms T&D rate issues and squeezes utilities' ability to invest. Utilities under PBR focus on distribution reliability and "free ride" on the congestion markets, in effect, for T reliability leading to declining reliability/capacity margins in transmission overall. The regulatory pendulum swings toward command and control. High costs combined with the regulators' focus on the total bill cause the wires companies to be squeezed.	Load growth continues, renewables supported but "T" investment and rates still a problem; market solutions not embraced Large rate increase requests driven by high fuels costs and deferred rate increases and freezes ending spur regulatory push back and result in insufficient funding for transmission investment. PBR rates tend to be more punitive and less rewarding.	Utilities can afford to invest but constrained by work force and conflicting (AMI) demands. Market-based solutions preferred politically. Moderate rate freezes and less resistance allows regulators room to embrace market solutions even if T&D rates will increase. Load growth and environmental issues still lead to capacity shortfalls and market-based demand side solutions are embraced, leading to an open environment for AMI solutions.	During a time when the need to address the aging infrastructure issue is widely accepted, this scenario is driven by political vision, security benefits, and advanced technology becoming commercially viable.	More dramatic electric supply failures (cost, reliability) lead to intensified regulation and a withdrawal from market solutions in any scenario.
Triggers (What causes this scenario to unfold?)	Cost pressures and inadequate rate increases as freezes end; imposition of PBR, and utilities' shares falling out of Wall St favor.	Economy benign but politics shifts away from market solutions and towards regulation and green energy. Same triggers as the "shock absorber" case but aggravated by stronger load growth.	Political awakening to energy issues; market (congestion based) "T" reliability metrics. Fuel costs continue to moderate, economy grows and interest rates are moderate; regulators embrace demand side and environmental (carbon) market solutions and encourage an "open" AMI solution; PBR rates increase for distribution. Aging infrastructure opens niche opportunities for entrepreneurs (locally, not grid driven).	Persistent, chronic problems with the aging infrastructure are deemed more expensive to customers than would be a fundamental upgrade of the system. Political consensus among FERC, NARUC, NERC, and others that a long view is preferable to short-term ad hoc fixes. Consumers adopt hybrid and electric vehicles and find the "Smart" technologies to be economically compelling as a result.	Blackout, nuclear failure, another Enron, large rate jumps (energy); oil shock, other. A visible and negative effect of global warming could accelerate carbon constraints and possible capacity limits.

	Shock Absorber	Muddlin' Thru	Market Choice & Rationality	Future Grid	Wild Card
Performance Axes (range of phenomenon and rational for each axis) • **Economic** • **Regulatory** • **Energy**	Regulatory climate is increasingly negative; energy overall is negative due to fuel costs, load growth, and slow adoption of new sources; and economy is negative due to slowing growth/higher interest rates.	Rates frozen or move slowly, approvals of new facilities delayed. Demand markets/TOU rates not embraced so mandated AMI unlikely. Energy and regulatory are negative while economy is positive. Regulatory lag prevents utilities from enjoying the benefits of growth.	T investment accepted but competes with D and AMI; political support for renewables, DG, and demand side markets. Increased load growth aggravates need for transmission investment. Regulatory, economy, and energy factors all favorable.	Macroeconomic growth holds to its long-term growth trend of 2 to 4 %. Favorable economics of grid optimization compared to local fixes is recognized and desired by regulators. Energy remains a priority issue because of cost, supply, and environmental concerns.	Events that dramatically change regulatory dynamic. All factors become negative but pressure for "someone" to step in and address likely shortfalls will be high
SCENARIO DRIVERS					
Macroeconomic Performance	Slower growth, higher interest rates	Benign or better	Benign or better	Economy on stable, long run growth path driven by population growth and improving productivity.	N/A
Utility Financials • **Rate treatment** • **Ability to invest**	Rates fail to keep pace; higher fuels costs pinch T&D rates; earnings/multiples decline for many utilities. Cost cutting in Transmission is the norm.	Rates increase slowly if at all; investment limited. No large demands for AMI other than as mandated in some jurisdictions. Utility investment focused on "D" as before due to PBR. External investors interested in "T" provided a mechanism to earn a return can be found.	Can afford investment but cannot manage all dimensions, too many things to do. Utility management willing to allow external solutions to transmission and to AMI as they see distribution as core strategic business for themselves.	Rate treatment is favorable for investments that replace aging infrastructure and strengthens the system in terms of reliability, controllability, and security.	Re-regulation returns industry to late 70's. (rate freezes, increased regulatory onus)
Transmission System Performance • **Reliability** • **Security** • **Congestion**	Reliability suffers and forced outages increase; capacity fails to keep pace; and congestion increases.	Reliability continues to decline; congestion increases. Similar to shock absorber but aggravated by higher load growth.	Seen as key component in energy infrastructure. Way is found to leverage congestion costs to spur investment/manage demand. Demand side market seen as alternative way to reduce capacity and manage congestion.	Fear of system failures and opportunities for improvement drives projects that improve performance on all dimensions.	Reliability source of "event"
Fuel Supply& Demand	Fuel prices stay high and volatility will be high increasing customer's risk aversion.	Fuel prices stay high and volatility is highest.	Fuel prices stay moderate and volatility decreases.	Fuel prices high and volatility is managed.	Adverse in most imaginable shocks. All scenarios add to volatility.

	Shock Absorber	Muddlin' Thru	Market Choice & Rationality	Future Grid	Wild Card
Wind Generation	Penetration due to regulatory/legislative mandates increases but true market driven growth does not materialize. Connection and siting issues remain as contentious.	Penetration increases due to high electric rates, load growth, and environmental pressures.	Penetration increases thanks to market solution rewards and innovation/investments. Utilities' ability to negotiate market connection solutions reduces contention. Siting issues still contentious. Possible Transmission ROW siting if easy connection developed	Enthusiasm fades but economic projects proceed.	Penetration accelerates in response to shocks affecting capacity.
Green Energy	Slow to develop due to rate freezes and lack of market mechanisms. Generation portfolio mandates.	Penetration increases driven by regulatory/legislative mandates.	Penetration (D level) increases as market rewards encourage innovation/investment.	Efficiency of the system becomes part of the green agenda.	Regulatory mandates increase penetration.
Distributed/Customer Generation	Cost and reliability issues lead customers to adopt on site generation whenever connection costs and technology issues do not make it infeasible.	Customer demand for DG forces regulatory imposition of connection standards that are not favorable to utility cost recovery and which do not address all reliability concerns.	Cost and reliability are not the drivers that they are in the "shock absorber" but market innovations continue to drive penetration.	Economical projects proceed as large end users see benefits for them in an improved grid.	
New Generation Technologies	Drawn in where regulatory mandates allow cost recovery. Locational, primarily.	Drawn in where regulatory mandates allow cost recovery or where market solutions persist.	Storage and clean coal likely as investors see ROI.	New technologies are deployed only when justified by the economics.	Depends upon shock? Faster nuclear approval; faster CGIT siting; wind siting all possible.
Environmental Drivers • **Carbon constraints**	Only adds to costs Regulatory caps result in capacity shortages as well as increasing market energy prices. Adoption of new technologies is slowed by environmental regulation. Carbon constraints affect dispatch adding to costs.	Adds to fuel costs and capacity shortfall. Likely to be regulatory caps rather than market solutions, or market solutions are more restrictive than in "Choice" scenario	Adds to fuel costs; creates market opportunities in both financial and physical markets/operations.	Carbon constraints and trading a reality.	Could be accelerated/intensified after environmental shock or could be delayed in face of major capacity shortages
Customer Technology	Rate freezes and costs slow innovation. Customers seek onsite power quality measures.	Failures/demand management encourage DG	DG primarily, incorporation of AMI secondarily. Large customers may seek to incorporate energy solutions/management with market information.	Increasing capabilities are being built into customer end-use devices. Electric vehicles and chargeable hybrids drive consumer adoption of the technology.	N/A although failures and shortages will encourage DG

	Shock Absorber	Muddlin' Thru	Market Choice & Rationality	Future Grid	Wild Card
Power System Technology	Lack of available investments slow innovation and adoption. Technology advances that do occur are for window dressing associated with mandated projects with little hope of commercialization.	External investors will appear for new facilities/ buyouts and possibly for repowering/reconductoring if a means of earning a return can be found.	More favorable investment climate encourages some developments – especially reconductoring and repowering.	Strongly favorable investment climate for power system technology	Localized capacity shortages (nuclear outage) would spur transmission solution
RTO/Customer/Supplier Value Chain Intersection	Lack of T investment and need to harvest congestion cost impacts leads to RTO as the regulator's choice for addressing capacity/reliability shortages. Utilities' cost cutting leads to fewer "in-house" EPC capabilities as competitors to RTO. RTO performs automation EPC; possibly leasing; performs asset management analytics/consulting. RTO moves risk from ROI to O&M recovery for utilities.	RTO performs automation EPC, leasing, asset management, demand control. RTO has three possibilities: Attract/enable external investment by ability to link market improvements (congestion) to investment return. Be the investor and EPC itself. In a planning/EPC role enable utility investment. RTO can facilitate moving risk to 3rd party investors.	Asset management is capacity/growth driven and demand side markets/AMI important; RTO can act as EPC/owner/lessor. Planning/investment validation RTO can perform planning and EPC for transmission upgrades and accompanying substation upgrades. Also can perform centralized AMI functions that serve market such as communications and data management. RTO can facilitate moving risk to 3rd party investors.	Intersection of RTO/customer/supplier value chains become broad and boundaries between RTO, utilities, and customers becomes permeable. Within the timeframe of the scenario, however, any repositioning of the value chains has not yet crystallized.	Planning/investment validation. Consolidated operations (reliability). RTO could become government partner in mitigating unacceptable risks due to supply failures.
Utilities	Retreat to asset ownership and focus on "D" to detriment of "T"; look at leasing/outsourcing as a way of controlling O&M costs and avoiding rate disputes; M&A/consolidation in response to regulatory costs	Retreat to asset ownership and focus on "D" for PBR reasons; do not want onus of demand management Willing to allow RTO or other 3rd party to step in.	Struggle to keep apace with investment needs and AMI/DG deployment. M&A/outsourcing operations are a way to succeed instead of way to survive.	Utilities are energized by the technology vision and the potential to grow the rate base but they are constrained by workforce retirements and subject matter expertise and experience.	Respond as in 70's – regulatory management the emphasis.
Market Participants	Continue "free-ridership" on T investments. Expect RTO to deploy/operate demand control.	Accelerate wind, DG, resist demand control. Will be pro or con RTO role in transmission investment depending on where they are.	Accelerate wind, DG and demand side. Numerous market participants and entrepreneurs find profitable niche projects.	Cross-subsidization is minimized as regulators and participants see capturable benefits for all.	Retreat in face of re-regulation.
RTO "Competitors"	Utilities, outsourcers	Outsourcers, utilities; other government agencies?	IT firms, outsourcers	Competition in all facets and the value chain gets rearranged and redesigned.	Large utilities, NERC

	Shock Absorber	Muddlin' Thru	Market Choice & Rationality	Future Grid	Wild Card
RTO "Partners"	Suppliers, consultants	Suppliers, consultants, communications suppliers	Suppliers, consultants, communications suppliers	Alliances, partnerships, and acquisitions with all segments of the market are a critical strategic question.	Suppliers, consultants, government
PERSPECTIVES					
Important Variations	Acceptance/mandate for load shedding	AMI for demand control (rationing)	Mandated vs. Market driven AMI; AMI is competitive or franchised		
RTO Role	White knight	Addresses the ragged edge	Seat at the table	Visionary leader and investor	Facilitator of solutions

Appendix F: Other Industry Business Scenarios

Other Industry Business Scenarios

Industry	Model	Example	Description & Role of Automation	Advantages	Disadvantages	Structural Comparison to Transmission	Lessons for PJM
Hospitality	REITs (Real Estate Investment Trusts)	Starwood Hotels	Asset is owned by a consortium of investors, managed by an independent company who guarantees performance and payouts based on a management contract. Starwood, in this case, brings unified brand standards, operations and supply chain. Chain uses IT systems for reservations and customer loyalty program to bind franchisees as well as supply chain management. Advertising / product management as with other franchises is also a factor.	Broader financing for real estate expansion, asset improvement. Exempt from Corporate Tax Insulation from operating risk, management firms might be better suited to running Asset rather than owners. Management contract, if designed properly, will have recourse for downside risk. Management companies bring synergies across operations economies of scale.	Owner has less control over asset, day to day operations. Long-term contract may limit upside of investment Danger of over or under valuing the asset.	Hotels neither regulated closely nor government franchised in most cases.	Asset management model for PJM, especially with regard to Substation Leasing. Hotel management companies can provide standardization of brand, PJM as management company can provide standardization of service and support.
Airports	FAA Airport Privatization Pilot Program	Stewart International Airport, Newburgh, NY	Signed 99 Year lease in 2000 with National Express Group, an operator based in the UK. Initial Payment of $35MM, plus 5% of Gross Income on the earlier of 10 year anniversary or 1.38MM customers. Though required to have approval of 65% of airlines, it has not achieved this measure. The deal continues, regardless. Automation played little or no part in this. The FAA itself is an example of major IT projects experiencing restarts, delays, cost overruns, and publicly visible failures.	State recouped initial $24MM investment in airport. Proceeds from lease agreement go towards improvement in airports. Efficiencies from management firm operation synergies across facilities, lower operating costs from economies of scale. Operation of the asset is separated from the cash flow requirements of debt service for cost of building the facility. Management company, separated from debt obligation, might be more willing to take risks, allow for new entrants in a push to diversify from competitors.	Lease deals depend on cooperation from tenants, airlines. Airlines have been reluctant to cooperate without receiving concessions. Structure might work better in single tenant, or one tenant dominant airports, where the management deal can accommodate the major player. Federal law requires airports to re invest profits. Program splits proceeds. Leasing program allows for payments to management company as well.	Airports are government owned, regulated, critical infrastructure and public safety, complex to operate.	Example of an asset management scheme in a regulated environment. Airport operators have to reconcile the requirements of government franchise with fiscal requirements of airport. Shows advantages of separating ownership of asset from operation of asset in high-capital investments. Operations company is not beholden to debt requirements of owner.
Railroads	British Rail Privatization	British Rail (Railtrack)	Implemented in 1994 Deregulation sought to establish a competitive process by splitting BR into individual units, then auctioning them off into private contracts. Maintenance of infrastructure given to Railtrack, government owned company on the LSE. Established in 1996. Passenger services split into 25 Train Operating Units, given leases to specific routes. Franchises awarded for 7 to 7.5 years if no new rolling stock added, 10 to 15 if rolling stock is added. Quality of service managed by an independent Rail Regulator, and Rail User Consultative Committees. Safety standards and accidents are managed by the Health and Safety Executive. Train scheduling and system operations are essecntially the same as before privatization - the flexibilities and market solutions available from automation have not been exploited.	Revenue generation for British Government Competition across TOUs	Lack of communication and cooperation across TOUs and with Railtrack created delays, unpredictable ticket prices, dirty trains. Perception of disorganization, distrust of product. Railtrack caught between obligations to government and need to negotiate with TOUs and Freight operators. Accusations that Railtrack's obligations to shareholders (and profit reports) create conflict of interest with obligations to safety and maintenance. Railtrack, as managerial entity, caught between three parties: Shareholders, Customers, and Government. Breakdown of vertical connections led to loss of communications that horizontal entities (such as Railtrack) has not been able to sufficiently overcome.	Was a government owned and regulated/franchised industry. Still is regulated and franchised.	Example of how the deregulation of a centrally-operated government franchise could fail. PJM, like Railtrack, could find itself caught in the middle of a turf war between utilities, government and its own shareholders, resulting in lapses of service. In the subsequent breakdown of vertical communications, PJM could find itself liable for subsequent congestion and service faults.
Wind and Renewables	Community Wind Model		Energy Project owned by a consortium of shareholders. Energy from project is sold to client by power purchase agreement or dispatched by grid operator Project is managed by third party operating group, under management contract. In many projects, contract is a fixed monthly payment, supplemented by bonuses or penalties depending on performance of project Automation anc control systems are key to low labor costs for operations and for integration with ISO systems. Project is also governed by a power contract with an offtaker, either a private entity or utility.	Management companies provide efficiency in operation that smaller projects may not be able to delver Aggregation of smaller projects under management provide greater economies of scale. Tasking management to third party operator creates measurement and verification opportunities independent of owner or energy customer.	Projects are unpredictable, inherent operating risk due to low availability and capacity. Upside potential can be limited	Regulated but not franchised.	PJM's broad geographic reach and technical expertise place it in a situation to advise and guide small renewables. Aggregation of numerous small projects can find economies of scale and efficiencies in management. PJM's role as a third-party operator can translate to a role as objective manager, providing third party verification and mitigating conflicts between owner and offtaker.
Nuclear	Small Nuclear Fleet Management	Entergy Nuclear	Entergy provides support and operations services for nuclear plant. Asset remains in hands of owner. Aimed at small, independent nuclear Automation of operations has been held back by Nuclear Safety regulations. Lack of operating flexibility has made many energy market participant IT systems superfluous. IT is exploited to reduce regulatory reporting. Deal with Nebraska Public Power: $12MM annual fee, with bonuses for safety and regulatory performance.	Efficiency in meeting operational needs of nuclear energy. Economies of scale by grouping independent nuclear with larger nuclear fleet.	Liability for nuclear operations. Risk and complexity of permitting and safety procedures.	Regulated with history in franchising. Critical infrastructure, public safety, highly technical.	Example of an asset management model that involves a highly technical, regulated, and risk-prone environment. Niche model that benefits from aggregation of projects, economies of scale. PJM could take a role as the expert in a specific technical area of energy asset management.
Order Fulfillment	Merging Delivery with Supply Chain	UPS Supply Chain Solutions	"System is the Warehouse" Predictive software, point of sale mechanisms, route inventory towards destination in anticipation of order. Shipping company becomes third party supplier. Handles shipping concerns-- transport, customs. IT integration and work flow systems essential to this restructuring	Short Delivery Times, "Just in Time" Inventory Lower warehousing costs b/c inventory does not sit in one place. Shorter "order to cash" cycle.	Misallocation of resources -- sudden spikes in underserved regions.	Unregulated, Unfranchised system that deals with a critical infrastructure.	Parallel example to PJM, of a company delivering just-in-time, coordinated services. Provides example to PJM of a company leveraging its core competency (in this case, delivery) to expand into a complimentary business. Example of using predictive technology to anticipate demand, potential bottlenecks and congestion.
Aviation	Air Traffic Control	FAA	Interlocked system of regional, local, and ground radar controllers. Required to maintain orderly takeoffs and landings between airports. Flight planning and routing remain essentially as they were prior to deregulation and last rounds of automation. A lack of market models for routing and prioritization leads to frustrating congestion and a lack of stakeholder incentive for improvement in	Centralized control, protocols used around the world. Ability to coordinate across regions.	Slow update of critical infrastructure. Lags technologically. Prone to cost overruns and delays. Management issues, bureaucracy led to delays in updates to technology. Example: implementation time and cost of WAAS (Wide Area Augmentation System) was underestimated, and set back by personnel changes. Expected to be implemented in 2001, not implemented until 2003. By then, cost had grown from $892MM to $2.9BN. Highly politicized system.	Example of a regulated, franchised system. Similar, as well, in its need to maintain and manage consistent flow of product (planes, people) across markets.	Example of institutional paralysis in an infrastructure company, difficulties operating in a critical infrastructure environment. Perception of FAA as inefficient operation. Example shows how important operational efficiency and delivery is to companies like PJM to maintain credibility.
Ocean Freight Logistics	Coordinating incoming and outgoing ocean freight, linking with land (train and truck) freight.	Port of Los Angeles	Freight Deregulated after coordinated Train, Truck, and Ship container system became hampered by shipping regulations and inflexible rate structures. Rail Deregulation: Shipping companies could sign long term contracts with rail companies, creating a business for the transfer of shipping containers from ports to rail and back again. IT systems integration, automated tracking, and work flow management have been essential to this restructuring. Shipping Deregulation, 1984: Shippers can sign long-term contracts with ship lines. Consistency in market vial long term contracts, competition from volume pricing caused shipping rates to become comparatively inexpensive.	Highly computerized, automated system that manages shipping logistics with freight management. Containers can be loaded and unloaded in a matter of hours. Arriving boats coordinated with arriving trains. Facilitation of just in time supply, shortening of shipment times.	Delays dramatically increase the cost of shipment. Efficiency of port tied to efficiency of port management company. Marginal cost management and economies of scale are key to profitability. Costs of shipping reliant upon volume.	Lightly regulated, unfranchised system. Heavily reliant on market economics and economies of scale. Uses technology to coordinate dispatch. High potential, due to security and critical infrastructure concerns, to become regulated again.	Parallel example of a critical infrastructure company tied to efficiency and economies of scale. PJM can draw examples of Port Operator's use of automation technology and predictive software to coordinate rail, trucking and freight, minimize shipping times, maximize capacity.

Appendix G: Generator Maintenance Scheduling in an ISO

White Paper
on
Market-Based Generator Maintenance Planning

By

Hans van Meeteren

KEMA Inc.

November 29, 2006

Revision 1.1

Table of Contents:

1. Introduction

Two approaches for bid-based generator maintenance planning are described: a non-market-based and a market- based approach.

In the market-based approach maintenance slots are assigned in an optimal fashion at no cost to the generators. Generators can then request a shift of the assigned period, as long as they are willing to pay for this based on the increase in total production cost.

In the market-based approach there are no free slots. Maintenance slots are assigned based on a bid and selection process that minimizes the cost of generator maintenance to the loads.

Variations that include linkages to capacity markets and overall availability are described.

2. Background

An ISO is responsible for coordinating and approving requests for outages of generation facilities. This background section is generic and does not attempt to capture the full details of any particular ISO scheduling protocols.

Generation outages fall into the following three categories:

- ***Planned*** – Planned Outages are scheduled by the Market Participants (MPs) well in advance and are of a predetermined duration. Turbine and boiler overhauls or inspections, testing, and nuclear re-fueling are typical Planned Outages. In the event that the initial Planned Outage request is denied, the MP re-evaluates its Planned Outage schedule and submits a new outage request. This process is repeated until the MP submits an outage request that is acceptable.

- ***Maintenance*** – A Maintenance Outage is an outage that may be deferred beyond the next weekend but requires that the Capacity Resource be removed from service before the next Planned Outage. Characteristically, these Maintenance Outages may occur throughout the year, have flexible start dates, are much shorter than Planned Outages, and have a predetermined duration established at the start of the outage. The duration of a Maintenance Outage is generally unlimited except during the ISO Peak Period Maintenance Season.

- ***Unplanned*** – Unplanned or Forced Outages are declared by the plant operator/MP on short notice and are ascribed to actual or anticipated failures requiring immediate maintenance attention.

It is important to emphasize that the ISO does not “schedule” when outages should take place. The ISO only accepts/rejects the requests for outages. The ISO only rejects outage requests when they affect the reliability of the RTO. It is the responsibility of each MP to determine its own best schedule of outages. Outage requests are honored by The ISO on a first come-first serve basis.

The generator outage scheduling, and especially procedures around unplanned outages, have come in for criticism in recent years. A frequent criticism is that generators will declare forced outages as a means of manipulating the market. This issue arises again and again in capacity tight markets where even a small amount of under capacity can cause very high prices. Alternatively, withdrawing capacity is a way to avoid very low prices when there is excess capacity. Related to this, the concentration of generator outages at shoulder months has led to unexpected capacity shortages and high prices or worse even in these normally “benign” periods.

In theory an MP should desire to have their plants scheduled for outages during shoulder months when prices are not expected to peak. However, a fleet owner may calculate that by restricting capacity during peak months prices will be increased and overall profits to the owner increased. At least that is the basis for allegations of market manipulation.

Additional complexities and difficulties can be anticipated as renewables and DG grow as a share of installed capacity. The aggregate availability of these sources as well as the linkage of capacity to weather conditions will complicate the day-ahead capacity adequacy problem for market/system operators. Average capacity for these resources will be expected to vary seasonally (as do hydro resources today).

Historically, vertically integrated utilities would perform optimal maintenance scheduling using algorithms that scheduled outages with annual expected production cost as an objective function and reserve requirements as constraints. Imports and exports were not normally considered explicitly as available resources to meet reserves or capacity requirements. Such an approach no longer works in a market environment.

3. Optimal Generator Maintenance Planning for Planned Outages in a Market Environment

Two approaches for optimal generator maintenance planning are presented in the following subsections:

- ***Non-Market-based*** – the ISO determines overall maintenance schedules based on MP schedule requests on an annual basis. The ISO uses an economic objective function to accomplish the scheduling and no there are no financial implications of ISO scheduling decisions.

- ***Market-based*** – The ISO utilizes a market mechanism to allocate desired maintenance schedules to MPs when there are excessive schedule requests in a given period.

3.1 Non-Market-Based Maintenance Planning

Some ideas for a possible service that would benefit the generator owners and loads:

- Allocate planned outage allowances to generator owners using an optimal generator maintenance scheduling algorithm considering:
  - Requested number of requested consecutive days
  - Preferred period in which the outage should occur. If the planned outage cannot be scheduled in the preferred period then a schedule should be provided that is as close as possible to the preferred period. Schedule requests would include an "opportunity cost" for shifting the schedule away from the preferred dates. Such costs, as with start up and shut down costs, would not be purely market-based but would be subject to reasonability review and restrictions on changes.
  - Reliability – ensuring capacity adequacy
  - Minimizing the aggregate opportunity costs incurred as a result of the schedule.
- If the planned outage cannot be scheduled in the preferred period then a schedule should be provided that is as close as possible to the preferred period. This is called the Most Optimal Generator Maintenance Schedule (MOGMS).
- Present the MOGMS to generator owners for approval.
- Charge generator owners when they request to deviate from the MOGMS. This charge should be based on any opportunity cost incurred by other generator owners due to a shift in their schedule. (Note: Maybe this cost should not be considered as long as the shifted schedule is within the originally requested schedule for these generators.)
  - Requests for deviation from the MOGMS would only be accommodated as far as they can be realized without moving other generators outside of their preferred period.
  - Reimburse other generators affected by schedule deviation requests for lost opportunity cost caused by a shift of their schedule away from the MOGMS.

- Allow MPs to 'trade" schedules on terms they establish but with ISO approval of proposed schedule trades.

This mechanism would be revenue neutral to the MPs; would result in schedules that nominally were optimal from the generator's standpoint, yet would allow the ISO to manage capacity adequacy for reliability (and peak price) considerations. However, the original MP opportunity costs for shifting are not financially settled as part of the "optimal" schedule. Were they to be, then the market (i.e., the loads) would have to compensate the MPs for the overall costs. Since the bulk of the costs are in fact energy market peak differential opportunity costs, this is not likely to be feasible.

An alternative that avoids this difficulty is to treat all deviations from submitted schedule as having the same worth. However, in this case the MPs whose plants were scheduled for outages during peak months might take issue.

These difficulties point out the problems in solving scheduling that has financial implications for the participants on other than a financially settled basis.

3.2 Market-Based Maintenance Planning

Market-based generator maintenance planning could be implemented as follows:

- Generators will have to bid for preferred slots. The number of weeks that are included in the bid can be longer than the required number of weeks. Within a bid period slot, bid prices may vary from one week to another. Generators would also bid for how much they would want to be paid for being scheduled in specified peak months.
- Since annual schedules can be determined with some leisure during a particular time period in the year before, a continuous auction process can be used to have the MP market adjust the bids until a schedule which is revenue neutral to the participants and acceptable to the ISO is determined. (Note: This is a concept which would require some proof.) At each step in the continuous auction the bids would be closed while the ISO re-ran the optimal scheduling algorithm to determine the prices and schedules.
- The ISO scheduling algorithm would use revenue imbalance as an objective function and capacity adequacy as a constraint. It could use the remaining imbalance at each stage as a signal to participants as to how to adjust their bids. Within the algorithm an "as bid" clearing mechanism could be used to allocate the preferred outage schedule slots to generators in order of prices bid, and to allocate undesirable slots in order of payments demanded.

- It may be necessary for the ISO to act as a proxy “payer” to get offers for units to be out during seasonal peak periods.

The virtues of this scheme include (if indeed it works) revenue neutrality. Also, generators would presumably ‘bid” their expected opportunity cost for being outaged, as modified by their perceived need to accomplish the maintenance. The continuous nature of the auction process would act to discourage gaming.

3.3 Unplanned outages

A desirable market mechanism for discouraging unplanned outages would be to have market-based costs for unplanned outages directly allocated to the plant operators. Since some degree of unplanned outages is an inescapably part of operating power plants of different types, the allocation may have to take this into account. Additionally, it is impossible to know what market conditions would have been without the unplanned outage. Any attempt to after the fact calculate such a figure would be subject to endless dispute.

A first question is whether to require all unplanned outages to compensate the market for their outage or to allow some “normal” availability to each class of unit. The first approach will reward those operators with better maintenance practices and will eliminate one gaming opportunity. The second could make sense in a capacity market environment where the capacity offers to the ISO would include availability metrics somehow.

The second question is what price to charge for an unplanned outage. The simplest alternative is to force the plant operator to acquire equivalent capacity or to allow the ISO to acquire it for them. This avoids the need to determine any market energy price impact.

Appendix H: Settlements White Paper

(This White Paper will be included later.)

Appendix I: Carbon Trading White Paper

White Paper
on
Carbon Trading

By

Hans van Meeteren

KEMA Inc.

November 29, 2006

Revision 1.3

Table of Contents:

1. Introduction

This white paper provides a short overview of developments related to carbon trading, both internationally as well as in the US. In addition, some ideas are provided about possible roles of Market Participants and an ISO in an ISO-operated carbon-constrained electricity market.

The information in this white paper could be used as a basis for a brainstorming session, the outcome of which could be used to update this white paper and define further actions.

2. Allowances

Material for this section is extracted from Reference 1.

Cap-and-trade programs for air emissions have become the widely accepted, preferred approach to cost-effective pollution reduction. One of the important design questions in a trading program is how to initially distribute the emissions allowances. Under the Acid Rain program created by Title IV of the Clean Air Act, most emissions allowances were distributed to current emitters on the basis of a historic measure ("historic approach") of electricity generation in an approach known as grandfathering. Recent proposals have suggested two alternative approaches:

- Allocation according to a formula that is updated ("updating approach") over time according to some performance metric in a recent year (e.g., the share of electricity generation).
- Auctioning ("auctioning approach") allowances to the highest bidders.

Research has shown that the manner in which allowances for carbon dioxide (CO2) are initially distributed can have substantial effects on the social cost of the policy as well as on who wins and who loses as a result of the policy.

A concern with a regional cap-and-trade program like the Regional Greenhouse Gas Initiative (RGGI) in the Northeast states of the US is the effect that different approaches to allocating emissions allowances will have on the level of CO2 emissions outside the region, commonly called emissions leakage.

How allowances are allocated has an effect on electricity price and the mix of technologies used to generate electricity. The electricity price increases the most with a historic or auctioning approach. Coal-fired generation decreases under all approaches but decreases the most under updating. Gas-fired generation decreases under historic and auction approaches but increases substantially under updating. Renewable generation increases under historic and auction approaches but decreases slightly under updating as a consequence of the expanded generation from gas. Consistent with the changes in the composition of generation, the decline in emissions of conventional pollutants including sulfur dioxide (SO2), nitrogen oxides (NOx), and mercury that was expected as a result of the Clean Air Interstate Rule (CAIR) is accelerated substantially, particularly under updating. The cost of complying with SO2, NOx, and mercury rules declines similarly. This suggests that carbon trading, other emissions trading, and generation commitment and dispatch cannot be considered independent from each other.

The above results are based on scenario simulations through 2025. Throughout the analysis, several assumptions have been made about underlying policies—federal and state environmental policies as well as market regulatory policies—that affect the performance of electricity generators. For instance, the assumption was made that electricity generators face requirements under the Nitrogen Oxides (NOx) State Implementation Plan (SIP) Call, Title IV of the 1990 Clean Air Act Amendments, and the Bush administration's draft Clean Air Interstate Rule (CAIR) for SO2 and NOx. The seasonal NOx SIP Call for 19 eastern states is in force for the 2008 simulation and replaced by the annual NOx constraint for a 28-state region under CAIR for the other simulation years.

3. Carbon Trading Principles

Material for this section is extracted from Reference 2.

Carbon Trading can be defined as a market-based approach to achieving environmental objectives that allows those reducing greenhouse gas (GHG) emissions below what is required, to use or trade the excess reductions to offset emissions at another source inside or outside the country. In general, trading can occur at the domestic, international and intra-company levels. Article 17 of the Kyoto Protocol allows for emissions trading between Annex B parties of assigned amount units (AAUs). A global market for emissions allowances is slowly being created. A voluntary emissions trading scheme was created in the UK at the start of 2002 and a smaller scheme in Denmark. From 2005, a mandatory European-wide emissions trading scheme is proposed to be launched and member states are currently in the process of drawing up allocation plans which will outline how various sectors of the economy will be affected. From 2008 full international emissions trading is envisaged under the Kyoto Protocol.

The carbon market encompasses both the generation of emission reductions (ERs) through project-based transactions where a buyer purchases ERs from a project that produces measurable reductions in greenhouse gases (e.g., investing in the construction of a wind farm), and trading of GHG emissions allowances allocated under existing (or upcoming) cap-and-trade regimes such as the European Emissions Trading Scheme (EU ETS).

The summary below provides an overview of the carbon markets as of 2005:

Project-Based Transactions

- The market for project-based ERs is still growing steadily: 107 million metric ton of carbon dioxide equivalent (tCO2e) have been exchanged through projects in 2004, a 38% increase relative to 2003 (78 mtCO2e). The volume exchanged from January to April 2005 was 43 MtCO2e. The number of projects under development also increased substantially.

- New buyers of emission reduction have emerged. Private and public entities in Europe represented 60% of the volume of ERs purchased through project-based transactions (Jan. 2004 to April 2005), against 21% for private and public entities in Japan and 4% for private entities in Canada.

- The supply of emission reductions remained heavily concentrated in a few countries, notably India – by far the largest supplier of project-based ERs on the market – Brazil and Chile.

- HFC23 destruction was the dominant type of emission reduction projects in terms of volumes supplied (25% from January 2004 to April 2005). Projects capturing methane and N2O from animal waste ranked second (18%), ahead of hydro, biomass energy and landfill gas capture (about 11% each). Projects abating non-CO2 emissions accounted for more than half of the total volume supplied, while traditional energy efficiency or fuel switching projects, which were initially expected to represent the bulk of the project based market, accounted for less than 5%.

- Due to the heterogeneity of the underlying projects and contracts terms, the spread of prices of project-based emission reductions at any given time was very large. Verified Emission Reductions traded between $3.6 and $5/tCO2e between January 2004 and April 2005, with a weighted average of $4.23.

Allowance Trading

- There are four active markets for GHG allowances as of May 2005:
  - The EU ETS
  - The UK Emissions Trading System
  - The New South Wales trading system
  - The Chicago Climate Exchange.

- Volumes exchanged on allowance markets increased dramatically and was comparable to the volumes exchanged through project-based transactions. Of the four allowance markets listed above, the EU ETS was the largest, with an estimated 39 MtCO2e exchanged since January 2004, the bulk of which was transacted since January 2005.

- In the EU allowances traded between €7 and €9 in 2004, but their price has increased substantially, to reach more than €17 in March and April 2005. Reasons for this price difference between project-based prices and prices for traded allowances in the EU are:

  - Less risk in trading allowances than engaging in projects

  - There are reasons to believe that the current prices do not reflect long-term equilibrium price between supply and demand: few entities are selling allowances, there are still large uncertainties over some national allocation plans, and weather and high oil prices have had an important impact on prices. Relatively thin volumes traded so far have also resulted in high price volatility.

Outlook

- Taken together, these developments suggest that the carbon market is responding to the ratification of the Kyoto Protocol

- Major uncertainties remain however, notably the absence of any price signal for emission reductions beyond 2012, limit the impact of carbon finance for projects with longer lead times. The amount of allowances that Russia and Ukraine will supply to the market is also a key uncertainty for the medium-term balance between supply and demand on the carbon market.

4. Developments in the U.S.

4.1 Regulatory Initiatives

The U.S. Congressional Budget Office (CBO) released a report in September stating that the most cost-effective means to reduce GHG emissions is to combine a mandatory price signal for CO2, which would be imposed by introducing either a nationwide cap-and-trade program or a tax on fuel, with federal subsidies for emission-reducing technology R&D. In addition, CBO found that if only one strategy can be implemented in the short-term, pricing CO2 emissions would be more cost-effective than subsidizing R&D, as initial pricing encourages low-cost reductions. After the CBO report was released, the U.S. Department of Energy announced a U.S. Climate Change Technology Program Strategic Plan to fund climate change technology R&D budgeted at $3 billion.

Some states have implemented a reduction target. Examples are:

- In Arizona an executive order has been issued that sets a target to reduce statewide GHG emissions to 2000 levels by 2012.

- In California a bill passed State Assembly, requiring the State of California to reduce GHG emissions within its borders to 1990 levels by 2020.

4.2 Chicago Climate Exchange

The Chicago Climate Exchange (CCX) is North America's only, and the world's first, greenhouse gas emission registry, reduction and trading system. CCX is a self-regulatory, rules-based exchange designed and governed by CCX Members. Members make a voluntary commitment to reduce GHG emissions. By the end of Phase I (December 2006), all Members will have reduced direct emissions 4% below a baseline derived from the period of 1998-2001. Phase II, which extends the CCX reduction program through 2010, will require all Members to reduce GHG emissions 6% below baseline.

The CCX Trading Platform is an internet-accessible marketplace that is used to execute trades among CCX Registry Account Holders. The system supports both exchange-cleared, which preserve anonymity, and bilateral trades that are established through private negotiations off-system. The Clearing and Settlement Platform receives information daily from the CCX Trading Platform on all trade activity. It processes all transaction information, nets out positions, and produces payment instructions for the settlement of trades.

4.3 Carbon Emissions Reduction in the U.S.

It is expected that a reduction of carbon emissions will be enforced using a cap-and-trade program for NOx, SO2, and CO2, patterned after the SO2 allowance program created in the Clean Air Act Amendments of 1990, which is the first large-scale program in the United States using a cap-and-trade policy instrument to achieve emission reductions. The SO2 allowance-trading program is generally considered a success. The attraction of such a system is that, given a well-functioning allowance market, generator owners with the lowest cost emission reduction opportunities would take advantage of them while selling any unneeded allowances they received to others whose reduction opportunities are more costly. The net result would be compliance with the emission caps at the lowest possible cost.

The number of emissions allowances owned by a power plant has a direct impact on the cost of generating electricity. For example, if a plant produced 0.200 metric tons of carbon per MWhr and the emission allowance price was $100 per metric ton, the operating costs of that plant would increase (increasing output requires purchasing more credits and reducing output allows credits to be sold) by $20 per MWhr ($100 x 0.2). Even when plants are given the allowances at no cost under a fixed allowance allocation scheme, each generator owner will attempt to pass on the full opportunity cost of the allowances in its prices. If this would result in a decrease in MW output, it would be beneficial to sell allowances that are not used. In the end there will be a balance between allowance trading based on the cap-and-trade market mechanism and the energy markets in which the plant participates.

4.4 Regional Greenhouse Initiative in the Northeast

In December 2005, seven northeastern states signed a Memorandum of Understanding (MOU) to implement a carbon dioxide (CO2) cap-and-trade program, called the Regional Greenhouse Gas Initiative (RGGI), to reduce CO2 emissions from power plants in those states. RGGI developed a draft Model Rule in early 2006 as a framework to guide the states to implement their share of the cap starting in 2009. Four New England states (Connecticut, Maine, New Hampshire and Vermont) were signatories to the RGGI MOU. For the years 2009 through 2014, each state's base annual CO2 emissions budget shall remain unchanged. Beginning with the annual allocations for the year 2015, each state's base annual CO2 emissions budget will decline by 2.5% per year.

The RGGI cap-and-trade program would create CO2 emission allowances for generators, which would have a market value. This value would be reflected in the generator bid prices for energy, similar to how SO2 and NOx allowances are reflected today. This additional generator cost could change the dispatch of the generators and their CO2 emissions.

The System Planning Department of ISO New England Inc. (ISO) has conducted a study to evaluate the impact that RGGI could have on CO2 emissions from New England's affected power plants and the likelihood of these generators, collectively, to comply with the RGGI cap.

As the carbon emissions cap is not explicitly modeled in generation scheduling and dispatch decisions, the cost of emissions allowances will determine how much emissions will be produced and whether the intended reduction of carbon emissions would be achieved. As expected, using a price signal derived from a just cap-and-trade policy would not necessarily achieve enough carbon emissions reduction. Other regulations should provide the necessary feedback to force a price signal that is high enough to achieve the desired outcome.

4.5 Carbon Emissions Management in ISO Markets

Scenarios for managing carbon emission are complicated by the fact that the carbon markets will include industries besides energy. Many of these other industries will leverage higher value products for lower carbon content. Consequently the value of emissions certificates will be higher to them than to the energy industry. As the total amount of carbon rights under caps decreases year over year, this will have the effect of crowding out the most intensive energy carbon emitters.

One possible market scenario that is decidedly undesirable is that the total amount of carbon rights available to power producers is less than their plants would need to operate at high (normal) utilization factors. Since the carbon rights are used on an annual basis, there is a risk of year end shortages in carbon rights and attendant capacity shortages – implying very high peak prices. It is not clear that the market will have sufficient information or incentive to balance the use of carbon rights throughout the year. Indeed, some plant operators might find opportunities to manipulate this situation to cause peak prices or to favor particular plants.

Note that this paper is written from the perspective that the plant operator is responsible to acquire carbon rights in order to produce. There is nothing in this philosophy that precludes a power purchaser from acquiring the rights and delivering them to the producer from whom they buy power. Some purchasers may elect to follow this path so as to insulate themselves from the annual shortage phenomenon. These purchasers would benefit from ISO information support and market transparency. Also, the ISO could facilitate the exchange of carbon certificates in this environment.

There are several possible scenarios for managing carbon emission in an ISO administered market:

- ***Decentralized Decision Making*** – Plant owners make all decisions with respect to the management of emissions with no ISO support other than the scheduling and dispatch of generators. Plant owners are involved with:

  – Trading of allowances

  – Adjustment of daily energy bids to reflect the cost of emissions in relation to the fuel usage

  – Keeping track of the rolling total of emissions and estimated emissions for the rest of the reporting period (year) to verify whether the total emissions will match the available allowances for a plant

  – Taking appropriate measures when there is a mismatch between the estimated total annual emissions and the available allowances. Measures could include buying or selling allowances or adjustment of the daily energy bids to reduce electricity and associated emissions.

  – Investing in pollution control equipment.

  The ISO would schedule and dispatch generators using the generator cost curves that are adjusted (by the plant operator) for the cost of emissions. Consequently, the market clearing price for energy may increase when the marginal generator's bid price has been adjusted for emissions cost. Considering that after the emissions cost adjustment the cost for coal-fired units will probably still be less than the cost for gas-fired combined cycle units, a market clearing price increase may only occur in low load hours. As a result a generator may not recover all its cost.

Fully decentralized decision making is vulnerable to the annual balancing cycles and year end shortages described above.

- ***Decentralized Decision Making with ISO Support*** – The ISO would support the plant owners by providing the following information:

  – Estimate of plant emissions for the balance of the reporting period

  – Estimate of market clearing prices for the balance of the reporting period.

Using this information a plant owner would be able to define its strategy on how to deal with a potential shortage or surplus of allowances.

The markets could be made more transparent if the current owners of all carbon certificates were made known and if the operators had to report to the ISO what certificates they had. By keeping the market fully informed the probability of carbon rights shortages is reduced. While this reduces an arbitrage opportunity – and would be opposed by traders – it would add market transparency and efficiency.

- ***Centralized Decision Making*** – The ISO performs some of the decision making. This may include:

  – Estimate the missions for the reporting period and the emissions for the balance of this period produced by each power plant based on plant-provided bids for energy adjusted for pollution cost.

  – Report to plant owners whether there will be over or under usage of available allowances based on the expected energy production. As a plant must have a sufficient number of allowances at the end of each compliance period to cover its emissions during that period, this information will allow a plant to take appropriate measures.

  – Determine whether there are enough allowances available to cover the total system load for the reporting period.

– Determine whether the purchase price of additional allowances would be offset by a decrease in the cost of energy for the consumers. If so, the ISO or affected generator owners could purchase additional allowances and charge effected loads.

– Track the use of allowances against physical production using an approved monitoring methodology.

– Define the best strategy for exchanging (maybe "borrowing with a certain compensation") allowances among market participants and trading on the open market (e.g., Chicago Climate Exchange) based on the outcome of the emissions estimate.

– In the settlement, separate the marginal energy price from the cost of emissions. This allows the total cost of emissions to be allocated to the loads based on each load's share of the total load.

– Acquire options on carbon rights (surely a market in these will develop) as a hedge on behalf of the load. The balancing energy market, in particular, will be vulnerable to price spikes due to shortages of rights. Options are one way for the ISO on behalf of the market to hedge against this.

– To the extent that the ISO may, on behalf of the market, have interests in carbon rights or options on them, it can perform a longer term optimization of anticipated energy vs. carbon.

5. Conclusion

This white paper provides some ideas on possible roles an ISO could play in the management of emissions in an energy market. There are many unanswered questions and details to be further defined before any recommendations can be made. It also may be necessary to do market simulations to verify how certain scenarios work out. Some issues that need to be investigated are:

- Separation of emissions associated with bilateral transactions from emissions associated with energy traded in the ISO market.
- Determining whether a more centralized approach would provide the lowest cost to the consumers considering that some of the market forces may not work anymore.

- Relation between capacities traded in a capacity market and available allowances. Should a unit's capacity be reduced when there is an expected shortage of allowances available to a generator unit?

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