ELECTRIC POWER RESEARCH INSTITUTE

Program on Technology Innovation: Managing Uncertainty in Planned Outage Scheduling

2016 TECHNICAL UPDATE

Program on Technology Innovation: Managing Uncertainty in Planned Outage Scheduling

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NOTE

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Abstract

This brief is a summary of the outcomes from the initial work of EPRI's Technology Innovation project on probabilistic outage planning. The goal of this work is to develop and demonstrate concepts for outage planning and scheduling that represent the growing range of uncertainty in power system operations. The initial work was to examine current practice and to enumerate the main potential enhancements that could be made to the various stages of outage planning.

Planned outages are necessary to maintain generation and transmission assets. These outages are normally scheduled years or months ahead of time and are often timed to occur when the system is under relatively less stress than during peak conditions. Transmission and generation asset owners submit requests to reliability coordinators who assess the request and grant outage permissions. Historically, it has been relatively straightforward to estimate the system conditions in the near future. With the changes occurring in the power system, estimating the system's needs in the near future has become more complex and less certain.

The goal of the project is to address the growing uncertainty in outage scheduling by understanding current processes and then identifying and demonstrating new methods to mitigate the risks associated with outage scheduling processes.

This brief lays out the generic process in place for outage scheduling in many parts of the United States at present. The brief also summarizes the emerging risks for outage scheduling and draws on responses from outage schedulers to identify potential enhancements to the outage scheduling process.

Several measures are identified as potentially beneficial for outage scheduling including risk based methods and methods to take into account advanced capability of generation units.

This brief provides a summary of potential benefits to planned outage scheduling in systems with growing medium and short term uncertainty.

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PRIMARY AUDIENCE: Engineers and Engineering Managers in outage planning and operations departments in transmission operators, independent system operators and vertically integrated utilities.

SECONDARY AUDIENCE: Generation outage planners, R&D engineers and reliability coordinator engineers

KEY RESEARCH QUESTION

Planned outages are required to facilitate maintenance of transmission and generation outage facilities. As the generation mix and network evolve to include more renewables, more distributed energy resources and new transmission technologies, new risks to the system occur that may need to be assessed when evaluating outage requests. The question that this report seeks to address is to identify what aspects of evolving power systems will require alterations to how outages are permitted, and what the potential mitigation measures might be.

RESEARCH OVERVIEW

This reports drew together insights from outage scheduling and operations when assessing the emerging risks when conducting reliability analyses for transmission and generation outage requests. The report outlines current processes for outage scheduling and outlines how the introduction of renewables, distributed resources and adoption of transmission technologies such as High Voltage Direct Current (HVDC) and dynamic line rating, can support and detract from some of the common assumptions made in the outage scheduling process. The report then points to some new methods and tools that have been developed for power system planning and operations to address similar concerns, that may be applied in the operational planning setting.

KEY FINDINGS

- The impact of renewable generation on outage planning at present levels in many ISOs can be managed using existing methods, but this is likely to change as the penetration of renewables increase.
- Uncertainty related to renewables and demand can play a significant role in the reliability risk during periods when transmission and generation outages occur. This uncertainty is currently managed using deterministic criteria, but may be better managed by moving to a probabilistic approach in future.
- Emerging system flexibility and frequency stability risks may become more important in future. This risk may require analysis in the operational planning and outage scheduling time frame.

WHY THIS MATTERS

Systems are typically designed to withstand a set of contingencies equivalent to the loss of a small number of generators or transmission assets in the planning time frame. Planned maintenance requires the removal of some of the assets that are assumed to be available to meet expected risks at the planning time frames.

Outages can be taken with no increased risk to the system if it can be accurately predicted that the system will not face scarcity conditions when the unit is on outage. As new resources and technologies emerge, our ability to make accurate predictions decreases. This report identifies methods to address that change to address the potential increased reliability risk as the power system evolves. This reduces operational costs through better utilization of maintenance resources and reduces the possibility of involuntary load shedding or system instability.

HOW TO APPLY RESULTS

This update report identifies the key factors driving change and the methods that can be used to manage that change. Utilities can use this document to evaluate their own outage planning process in the context of renewable integration, distributed resource adoption and the build out of new transmission technologies.

LEARNING AND ENGAGEMENT OPPORTUNITIES

- This work will continue over the coming year to apply some of the probabilistic planning and operational techniques to outage planning problems.

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Section 1: Introduction

Outage planning in the context of bulk transmission networks is the scheduling of maintenance both on transmission and generating plant while taking into account security of supply, safe and economic operation of the power system, market requirements such as congestion management and the maintenance, environmental and resource needs of the plant owners.

It is a critical task as emphasized by the vice-president of Technical Services at Southern company in 2012 when she stated:

"The long term success of Southern Company, the ability to safely provide reliable, low cost energy to our customers, and the preservation of our assets depends on proper outage planning and execution".

Outage planning varies with both geographic location and the position the network occupies relative to its surrounding environment. For example, winter peaking networks have historically performed maintenance during the lower load periods in the spring, summer and autumn while summer peaking networks undertake their maintenance in spring and autumn. Networks which form part of critical network links or which provide support to neighboring networks will have their planned outage schedule dictated by these types of commitments.

The purpose of this briefing document is to outline existing practices in determining planned maintenance outage schedules and to understand whether these practices are suitable in an evolving power system. This assessment is from the point of view of multiple actors including; transmission owners and operators (TO or TSO), generation owners and operators (GENCO), vertically integrated utilities (VIUs) and independent system operators (ISO), Figure 1-1. The document does not seek to evaluate the practices used by asset managers and subject matter experts in evaluating the need for maintenance to be carried out on an asset: rather, it is focused on how best the maintenance can be carried out as part of a network of interconnected devices meeting the reliability, safety, sustainability and economic goals of the power system. By evaluating the methods used and the challenges posed by new participants in the power system, potential areas for research and development can be identified to help ensure the reliable and economic operation of the power system.

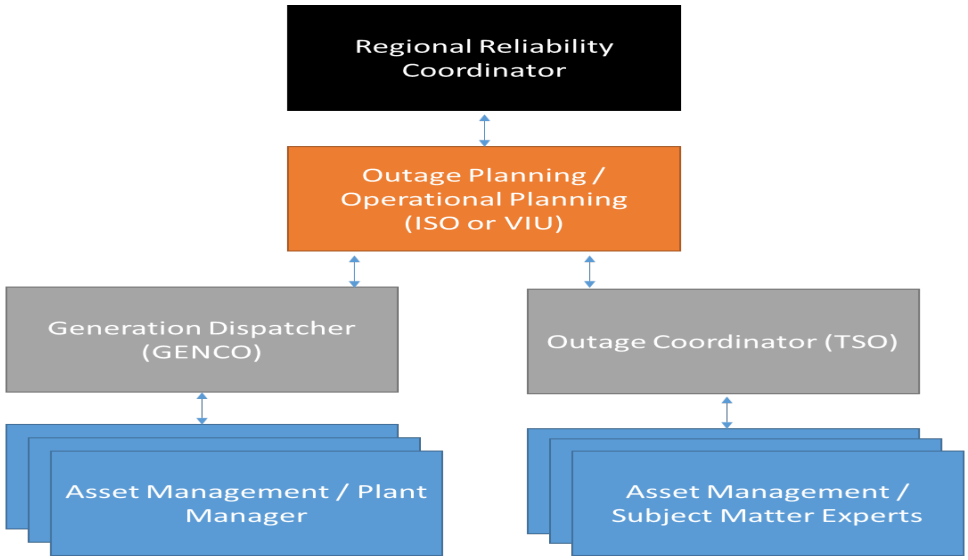

Figure 1-1
Flow chart of typical operational planning process

This introduction section outlines the overall process of outage scheduling as it is today. The following sections detail the tools and processes used to evaluate and coordinate outage scheduling decisions and the new factors which are emerging that may influence how outage scheduling is carried out in practice. The final section draws together some conclusions for the industry to consider as further work to conduct in this area.

1.1 Coordinating Maintenance Needs

Coordinating maintenance outage requests across numerous entities has always been a necessary and challenging problem. Without adequate maintenance, electricity becomes less reliable and more expensive. In outage planning, the most important co-ordination that usually must take place is that between transmission outage and generation outage schedules. The most obvious reasons for stating this are, for example, that without transmission a generator cannot deliver and if the generator is available the transmission plant owner or operator could incur financial penalties or opportunity costs. Another simple example which requires a great deal of co-ordination i.e. performing maintenance on transmission line can involve a number of different groups in a company. These can include line staff, station staff, protection experts, communication engineers and civil works.

However, liberalization of the power industry together with new organizations which have emerged following events such as the 2003 blackouts in Europe and the US has resulted in a more complex organizational landscape. For example, in the US we now have Reliability Coordinators (RCs) and Regional Transmission Organizations (RTOs) working together with existing utilities. Additionally, NERC/SERC [1] have established long and short term study groups (LTSG and STSG) to examine long and short term outages and to consider issues such as reserve provision. The Eastern Interconnect is establishing a data sharing network to develop a mechanism by which essential operational data can be shared securely, consistently and efficiently among the Eastern Interconnect Reliability Coordinators (EI RCs) and other appropriate entities [2].

In Europe new organizations such as CORESO [3], TSC and SSC which are centralized Regional Security Coordination Initiatives (RSCIs) have emerged. These RSCIs develop and perform operational coordination services in cooperation with TSOs and other RSCIs, while TSOs remain responsible for operation. Ensuring all of these entities work in harmony to optimize outage planning is a significant co-ordination challenge.

At each point in the operational planning decision process, different risks are assumed depending on the industry structure in a region. Generation and transmission resources will need to manage their lost revenue opportunity cost which can include energy, ancillary service and capacity payments. ISOs and utility reliability coordinators need to manage the security of supply risk to their given region with respect to a number of criteria, including generation and network capacity adequacy and dynamic stability. As discussed later, the risks that each player is facing are changing: this has implications not only for each actor in isolation, but for the coordination between each part of the system.

1.2 Outage Planning Horizons

The long-term horizon for transmission plant could be up to five years ahead while the horizon for nuclear generators could be up to 30 years. Table 1-1 outlines typical timescales for both generation and transmission maintenance scheduling. To cater with these different requirements, outage scheduling usually falls under the remit of short and long term operational planning groups. The short term group will typically manage outage planning from a real-time to a number of months out, while the long term group will handle the remainder. While both groups would use the same security criteria, the tools and information available to evaluate outages can differ substantially from what materializes in practice: short term outage study groups will obviously have current information which enables them to make a more informed final decision, but they may not have as wide a range of potential solutions available to them given limits in getting crews, spares and equipment in place. Opportunistic outages can arise when owners of specific assets request an outage at the same time as the planned outage of other equipment that would have otherwise taken of the asset in question out of service. An example would be an outage request for a current transducer at the same time as a disconnect outage.

Table 1-1
Maintenance Horizons

Area/Timescale	Long term	Short term	Opportunistic
Transmission	Typically 3 to 18 months but can be up to 5 years	Typically less than 1 month	Days to real-time
Generation	Typically 2 to 3 years but can be up to 30 years for nuclear units	Typically less than 3 months	Days to real-time

These lead times are required for a number of reasons: hardware replacement parts and software upgrades can have long design, manufacture and logistical lead times and require extensive specialized manpower which must be committed in advance. Given the pace of change in the industry, long lead times may expose the asset owner and system operator to significant risk.

1.3 Regulatory Drivers

Outage planning must take place within the regulatory framework established for that region. Organizations such as NERC and FERC set and enforce the reliability standards for the electricity industry in the USA. Failure to comply with these standards can lead to penalties and further consequences for the parties involved. These standards are constantly evolving as the challenges to system reliability change so that those involved in the electricity industry must be readily able to adapt to the new standards and be in a position to operate to them [4].

Similarly, in Europe, security standards were previously defined by the UCTE ENTSO-E Operational Handbook. These have now become part of the network codes, some of which are not yet finalized but early drafts are available [5]. In particular, the network code on operational security articulates the standards interconnected systems must adhere to. National standards supplement these pan-European standards to manage the unique characteristics of each region. These regulations have been drawn up based on the reliability goals for each given system and are revised based on knowledge acquired from events and studies as well as in anticipation of new challenges for system operation.

While the standards by which reliability is assessed remain relatively constant, the increasing number of technologies deployed in the power system can pose new challenges to reliability under certain conditions and increase reliability in others. System operators and reliability coordinators will have to ensure that tools and methods they use are suitable, to extract the necessary support capabilities from these new technologies, as well as assessing their potential impact on system reliability.

1.4 New Technology – Renewable Generation

The advent of renewables such as wind and solar will impact on outage scheduling but it shouldn't be forgotten that hydro generation has always been a complication in outage scheduling i.e. no water when it is required to allow an outage proceed and excess water when generators should be off load.

Renewables provide a specific set of challenges that need to be addressed in the long-term and short-term outage planning time frames:

- By their nature they are stochastic, so while it may be possible to predict production levels relatively well for the next 24 hours, how can this be achieved for the next 3 months during a critical outage? The stochastic nature of these forms of renewable generation manifests itself in two forms i.e. the total capacity available (distributed PV in particular) and weather driven uncertainty.
- Flow levels on transmission and distribution lines as well as distribution transformers can reverse with the installation of solar PV or wind generation at distribution level.
- Load modelling for power flow studies with changing wind or solar production. Similar concerns arise related to the assessment of short circuit levels and transient stability issues, particularly with respect to frequency stability in the presence of reducing inertial capability.

As the penetration of renewables increases the need for ancillary services also increases. Both transmission and generation outage scheduling may have to account for this i.e. outages which restrict or halt ancillary services from either a section of the network or from a generator may not be possible or face restrictions.

Finally, it should be noted that the advent of significant levels of renewable generation may lead to increased cycling of steam and gas turbine plants thus altering their maintenance cycles [6].

1.5 New Technology – Distributed Energy Resources

As well as changes in generation technology at the bulk system level, changes are happening also at lower voltage levels where distributed generation is starting to become pervasive. Growth in PV, wind, CHP as well as storage and demand response at the distribution level may have consequences for maintenance scheduling at the bulk system level at sufficiently high penetrations. The increasingly bidirectional flow capability between distribution system and bulk system can potentially support the bulk system during outage periods as well as requiring reliable market access for aggregated resources in some systems at certain times.

Controllable distributed energy resources (DER) offer the potential to support the system in cases that currently prove challenging for outage scheduling. The ability to schedule increased production in an area can alleviate N-1 constraints on the line and defer the need to reinforce transmission due to outage conditions.

This capability is dependent on the availability of the DER devices which may have seasonal or diurnal traits. Where this capability is being relied on to support the outage of a transmission line, this constraint must be considered as part of the scheduling process through appropriate availability forecasts and forecasts of uncontrollable embedded generation.

1.6 New Technology—Network Assets

The increasing use of new technologies such as power flow controllers and dynamic line rating equipment is going to impact on outage scheduling. For example, in relation to dynamic rating equipment how do we know what the rating of a line will be in 6 weeks or even in 6 days? Figure 1-2 outlines some of the complexity involved in defining the actual limit of a line [7].

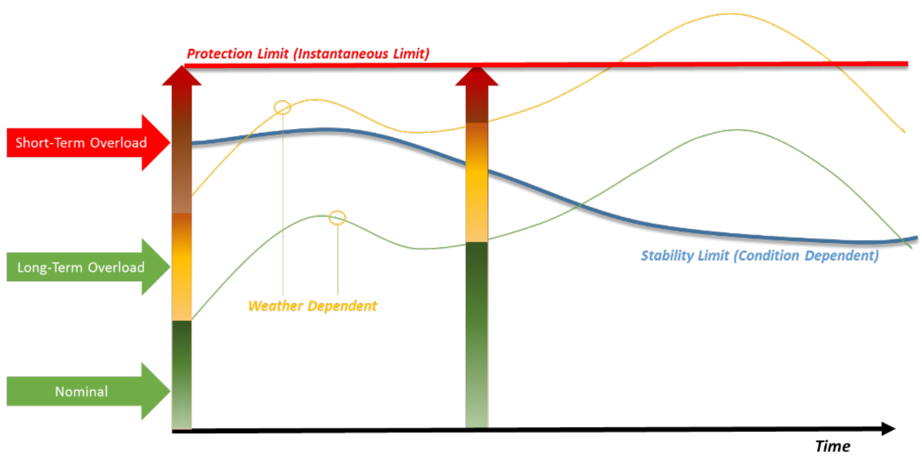

Figure 1-2
Dynamic Line rating – finding the limits

It should be remembered that lines or cables are not the only limiting factor. Power transfer between two points may be limited by other equipment such as circuit breakers, disconnects, transformers, measurement devices, filters and busbars.

Due to the inability to build new assets many companies implemented SPS or RAS schemes to cater for system contingencies. These can vary from simple low frequency or voltage load disconnection to winding back generators based on line loadings or reversing the flow on interconnectors to eliminate or reduce excess generation.

While these schemes can appear to be quite simple, their interactions and influence on the power system can be complex especially during outages when the system is in an abnormal configuration. A further difficulty arises when modelling these facilities especially when performing power flow and /or contingency analysis [8].

Power flow controllers will offer new possibilities to shift power flows to create a window of opportunity for maintenance on critical system assets. The widespread adoption of FACTS devices will also influence outage planning. The loss of one of these devices which, say, provides reactive support, may impact an entire area rather than just the busbar it is connected to. Conversely, the ability to retain the same device in service may allow for more aggressive outage scheduling than was previously the case. In addition to reactive support provision by FACTS devices, several utilities are now converting retired generators to synchronous condensers. In Germany, the retired Biblis A 1200MW nuclear generator was converted in to a synchronous condenser with a reactive capability of -400 Mvar to 900 Mvar [9].

Embedded HVDC links are also being considered as an alternative to overhead AC line construction. CIGRE has studied this possibility in a technical brochure [10].

Section 2: Current Practice

This section highlights the issues related to existing tools used for outage scheduling. By understanding the current process, the goal of this work is to be able to identify how the current tools and practices manage the outage scheduling process. This overview was constructed based on 6 interviews with ISOs, TOs and reliability coordinators from across the US and in regulated and de-regulated regions.

2.1 Co-Ordination

One impression which comes across from discussions with entities involved in outage scheduling is that there is no single overarching plan for all outages. Outages are granted based on a request queue that comes to the reliability coordinator through a variety of channels as shown in Figure 1-1. Ideally, coordination would occur internally between subject matter experts in transmission owners to minimize the amount of time the asset and related assets go on outage (e.g. related breaker, relay and CT maintenance outages during scheduled transformer outage). While this type of coordination does take place to some extent, is not always appropriate if assets are on different maintenance cycles.

Coordination between the transmission owners and generation owners with ISOs or reliability coordinators is a critical part of the outage planning process. Certain tools and platforms are commercially available to log and manage outage planning requests to assist in this coordination process. The current practice is to require notification of outage requests based on the duration of the intended outage or based on the importance of the asset to the operation of the system. Reliability coordinators then have the job of determining how and whether to grant the requests, subject to the regulations and operation procedures applicable in each area. This process includes the various types of analyses carried out in order to approve an outage.

Coordinating outages between TSOs and Generators to occur at times when it is beneficial for both, as well as for the system is clearly a desirable outcome. An example is the scheduling of outages on transmission lines linked to generators. If a generator applies for an outage from the system operator, an outage on a related transmission element may have little additional reliability consequences. Coordination of this type has taken place in some areas between stakeholders and is facilitated by reliability coordinators.

2.2 Modelling and Analysis

Outage schedulers highlighted the variations which arise between real-time and planning tools. Planning models tend to be used by long-term outage planning teams while short-term outage planning is typically conducted with a recent real time network model case, Table 2-1. For example, in ERCOT, the real-time model is updated on a weekly basis while the mid-term (> 45 days) planning model is updated every month. The loss in modeling accuracy between long term and short term planning has typically not been significant or has been well understood due to experience. Whether this practice can be as effective in future with high renewable penetrations is a question worth considering in future.

Reliability coordinators usually study steady state thermal and voltage performance of the system with the proposed generation and transmission outages for a given date at a number of lead times. The process can start from as far back as 90 days in advance, and is then incrementally updated until D-1. Coordinators also study the capacity adequacy of the system for each day to manage the risk of load curtailment due to insufficient generation. The inclusion of both stability and fault circuit analysis is now being considered by a wider range of schedulers. Typically, this is due to the altered nature of their networks where a large proportion of their generation is now remote from the load centers and/or where traditional synchronous generators have been displaced by renewables.

Each of these studies require input assumptions about the future state of the system during the outage period. For example, renewable output assumptions are key criteria for a number of systems with high penetrations of renewables. Renewables' production can be extremely difficult to predict for horizons greater than one or two days. This can often leave the decision to proceed or not with an outage in the hands of the control center or real-time system operator, who, on occasions does have to cancel outages. Outage planners maximize the knowledge they can garner from the data they have by, for example, undertaking a range of studies based on different levels of renewable production.

Table 2-1
Current outage scheduling evaluation tasks

Reliability Concern	Analysis	Conducted By
Line thermal limits	Power flow with contingency analysis - Selected peak network stress conditions during outage horizon (high and low)	Reliability Coordinator
Voltage limits	Power flow with contingency analysis - Selected peak network stress conditions (high and low)	Reliability Coordinator
Stability analysis	Dynamic studies as needed (varies from system to system)	Reliability Coordinator
Generation capacity	Capacity margin analysis	Reliability Coordinator
Generator reliability	Evaluation of best-fit window for generator outage requests	Generation owner
Transmission asset reliability	Evaluation of outage window for asset maintenance needs	Transmission owners

2.3 Post Event Analysis

One area that may not achieve the attention it requires is post outage analysis. It has been suggested that this area could provide feedback which would help develop subsequent outage programs. It's not clear whether a tool as such is required to undertake this task or whether a simple investigative approach be adopted where pre outage forecasts and post outage outcomes are analyzed and compared and the underlying reasons for any significant differences are ascertained.

Section 3: Potential Process Evolution

This section will discuss tools that may be required to deal with the evolving power system and new technologies. The following areas will be highlighted:

- Coordination
- Renewables
- Adoption of risk based transmission planning methods
- Outage duration uncertainty
- Embedded HVDC
- Dynamic Line Ratings (DLR)
- Remedial Action Schemes / Special Protection Schemes (RAS /SPS)
- Low utilization resources

3.1 Coordination

Co-Ordinated outage planning is required to ensure that, the TSOs and ISOs can co-ordinate, optimize and approve outages of generators. The principles of the process are to work in accordance within their respective remits and connection agreement or Grid Code obligations to minimize reliability risk while facilitating the outage of both transmission and generation assets.

The TOs, TSOs and ISOs should consider all system constraints and endeavor, where applicable, to provide maximum mutual support between generation and transmission. TOs, TSOs and ISOs will jointly agree outages of any interties or interconnections between neighboring areas, taking into account the implications for both transmission systems resulting from no support being available across the interconnector(s). This can involve regional reliability coordinators in areas where they exist.

TOs, TSOs and ISOs will maintain outage plans, which include scheduled and forced outages and publish them periodically. Depending on the type of outage, plans may have to be published for the short (weeks), medium (months) and long (years) terms.

It has been suggested that an ideal scenario would be one where there is a single tool which would gather and schedule all outage requests to an ISO or RC. This would consist of a coordinated request sub-system, which exists today, coupled with a scheduling sub-system. The scheduling tool would be used to optimize outages based on windows of opportunity provided by the asset operator. This would be a very large optimization problem and would, in effect, change many existing outage scheduling systems from permission based systems to a quasi-optimized system. This type of system would obviously have to be linked to a comprehensive asset database. It would also, at some point, need to link to work schedules for construction projects and emergencies.

Coordination internally within TOs was highlighted as an area for which improved practices could be brought to bear. Internal coordination between SMEs for different asset classes (e.g. transformers, breakers, relays, CTs and lines) could help to improve the number and duration of outage requests for linked assets. The solution to this could involve tool or algorithm development but would likely benefit most from internal coordination practices between SMEs and the reliability coordinator.

3.2 Renewables

To overcome the scheduling challenges posed by renewables it appears that:

- Both planners and operators should be using the same or similar tools and databases and that
- Forecasts for renewables with longer time horizons (2-3 months) than currently employed would be desirable

It is difficult to know if either of these are achievable, especially the 2-3 month ahead forecast requirement. A more attainable solution may be to derive a study methodology which accounts for the most likely range of renewable production scenarios based on historical seasonal data and current trends and which accounts for uncertainty for the outage schedulers.

Furthermore, the increasingly distributed nature of renewables means that they affect not just the bulk system, but also the apparent demand from the distribution system. As a result, the impact of renewables on the demand forecast must also be considered. This may require a different forecasting approach and change the definition of the study cases for transmission network analysis. As distributed storage becomes more pervasive, its impact will also need to be factored into short-term forecast projections and analyses.

The impact of renewables on the demand profile is well documented to date. Renewables often reduce the peak conventional generation required to meet peak load in a day. This, in turn, impacts the assumption for the peak and minimum net load case for both capacity adequacy and transmission network reliability analysis. This aspect is well understood, even if long term forecasts are not yet applied in current analyses. Recently developed capacity credit techniques could be one potential method to include in margin based calculations for short term planning [11].

A separate, but important, impact is the variability associated with renewables. While a system may have sufficient capacity to cover the range of peak net loads (subject to the forecast uncertainty of demand and renewable production), the system may not have sufficient flexible capacity to meet the expected ramps in operation. This may cause peak prices or trigger reliability events, not due to capacity issues, but due to ramping issues. In certain capacity market constructs, or in energy only market constructs, this can result in a revenue impact for the generators on planned outages during these periods. Tools and algorithms have been developed to examine flexibility needs in the long term planning process [12], but may be required for short-term operational planning to ensure that the system has sufficient flexibility when fast start or flexible resources are unavailable due to outages.

The effect of taking out of service plant items which are necessary for providing ancillary services has also been mentioned previously. In order to cater with this issue and to manage the flexibility issue, it may be useful to include an ancillary services requirement and adequacy calculation step in the study methodology. This would track all ancillary services i.e. calculate both the AS requirements and the available AS resources and highlight when an outage forces them under a pre-defined threshold.

Network re-configuration is a mitigation measure which would allow schedulers cater for difficult scenarios such as low demand together with high wind production. Advisory tools in this area would be extremely useful but it should be noted that any tool, to be viable in this area, must be able to re-configure busbars down to the section level which by its very nature dictates the status of line/cable, busbar and coupler disconnects. Additionally, network re-configuration tools will ultimately have to cater with phase shifting transformers and all of the items discussed below i.e. FACTS, DLR and RAS/SPS.

3.3 Adoption of Risk Based Transmission Planning Principles in Outage Scheduling

Significant effort has recently been put into developing tools and methods to conduct transmission planning according to risk based principles. This shift is in recognition that there are multiple potential causes for transmission capacity to be insufficient to meet the needs of the network beyond peak and valley demand cases. Multiple layers of risks have been identified as potential drivers of uncertainty in the transmission planning process including macro level concerns, such as environmental policies and fuel costs; medium-term concerns, such as generator location and short-term concerns such as forced outage rates for network assets [10]. By defining a framework in which the reliability of the transmission network can be assessed considering the uncertainty associated with multiple factors, a more realistic representation of the system's reliability can be gained.

Tools such as EPRI's TransCARE transmission reliability assessment tool combined with study case sampling tools can be used to test the reliability of a transmission network in multiple potential stress conditions for the network that are dependent on weather or other stochastic processes. The tools can also examine the effect of post contingency actions when assessing the system's reliability. This means that the deployment of reserve and network asset switching can be counted on to mitigate the need for undesired load shedding. The tools then determine the smallest demand reductions required to meet standard operating criteria. These assessments result in familiar reliability indices such as expected unserved energy (EUE) and loss of load expectation (LOLE).

At present, outage scheduling focuses on ensuring that the network reliability is maintained during peak seasonal net demand and in select valley conditions. Generation adequacy is measured based on meeting a seasonally adjusted capacity margin. These forecasted peak stress conditions will become more difficult to estimate for the reasons articulated in the previous section. Therefore, a method which directly models the uncertainty profile as it evolves may be beneficial in ensuring outages are granted while system integrity is maintained.

Reliability coordinators currently accept generation outage requests based on the security needs of the transmission system as well as the capacity needs of the system. The capacity needs are often assessed as an available plant margin above the expected peak demand in the outage season. This is a heuristic for the uncertainty associated with system contingency reserve needs and demand forecast error. As the profile of the net load changes with the advent of renewable generation, forecasting the peak seasonal net load changes also. In this case it is not as straight forward to forecast net load as the uncertainty associated with renewable generation capacity, as well as production are added to the demand forecast uncertainty.

Manging forecast uncertainty may be possible through the growing number of simulation tools that leverage stochastic or probabilistic methods. This in turn requires multiple long term forecasts for demand and variable generation. Long term forecasting is a growing area of interest where the focus is on characterising the uncertainty associated with seasonal demand or production from renewables. This is a key part of risk management in the operational planning time frame.

From the perspective of the generation owner, risk based methods can be valuable in determining the timing of generation outage requests. As planned outage requests are determined well in advance (5 years or greater), the generation asset owner must balance the maintenance needs of the unit with the potential lost revenue from not being available during periods of peak system stress when prices are typically highest. If generation owners plan outage requests within a window of opportunity (based on unit constraints, availability of staff/expertise/ parts) applying a risk based approach within that window of opportunity may be beneficial from both an asset owner point of view and from a system point of view.

3.4 Embedded HVDC

There are limited numbers of embedded HVDC schemes operating in parallel with a synchronous AC network at present [13], however this is expected to change in future due to the need for new long distance transmission to increase due to the challenges in building high voltage AC assets over the same distance.

Considering embedded HVDC and the operational issues and challenges they will present may be a good indicator of the issues that FACTS present in general.

HVDC connections perform differently to AC connections during steady state, dynamic and transient conditions. Compared to AC links, embedded HVDC links offer specific functions that can be seen as advantages but with additional costs and complexity. For example, the coordination between HVDC links and AC lines in parallel will be a new area of study for outage schedulers to optimise the economic transfer capability in the system while maintaining system security. As a result, the operational mode of HVDC links may vary according to the state of lines in the AC network.

Therefore, the inclusion of embedded HVDC into power flow with appropriate representation of its operational mode and contingency analysis may require enhancements for the existing toolset. Additionally, work will be needed to develop the operational modes for embedded HVDC operation, considering both the parallel AC system, but also other embedded HVDC links. By changing operational modes, real time constraints in the AC may be managed by leveraging the power flow control of HVDC. This logic extends to other more established technologies such as phase angle regulators and power flow control technology.

3.5 Dynamic Line Ratings (DLR)

DLR technologies enable transmission owners to determine capacity and apply line ratings in real time [14]. This enables system operators to take advantage of additional capacity when it is available. Unlike static ratings, dynamic ratings are calculated in real time based on the transmission line's actual operating conditions at specific moments, rather than on fixed assumptions. Dynamic ratings are often, but not always, greater than static ratings.

DLR technologies deploy weather sensors for wind speed, ambient temperature, and solar radiation and/or gather data from line temperature, tension, sag, or clearance sensors. Communications technologies transfer data to a server which determines the maximum dynamic rating for the specific conductor and environmental conditions. These ratings can be incorporated into a control system, such as a Supervisory Control and Data Acquisition (SCADA) system or EMS, to make them accessible in the transmission owner's and/or system operator's control room.

The forecasting issue arises again in relation to this technology. How do outage schedulers predict the flows that will be possible on lines equipped with DLR in order to take advantage of the additional capacity? In the case of DLR, it may be even more difficult than for renewables since weather forecasts may only be required for extremely small areas where the line rating is at its lowest value.

Having ascertained the new line's capacity, they then have to be made available to the outage planners and real-time operations staff for use in power flow and contingency analysis. A strategy on how DLR ratings are adopted will be necessary, at the very least.

3.6 Remedial Action Schemes / Special Protection Schemes (RAS /SPS)[1]

Remedial Action Schemes / Special Protection Schemes (RAS/SPS) have become increasingly necessary for companies unable to add new assets to their transmission infrastructure. They are automatic protection systems designed to quickly detect abnormal predetermined system conditions and take a predefined action to prevent a system problem [15]. They may take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability.

Typically, an N-1 contingency triggers one of these schemes. The question for schedulers is how are these schemes modelled in power flow and contingency analysis and is there a risk of different schemes interfering or interacting with each other in certain scenarios? The modelling of the actions of these schemes may be accounted for in N-1-1 reliability analysis calculations.

3.7 Low Utilization Resources

Many systems will have small assets or resources which are deployed only in rare or well defined circumstances. These resources may include relatively small capacitor banks or inductors or similar devices. These resources can often trigger the same number of studies as the outage of larger or more critical assets on the transmission network. Reliability coordinators highlighted the potential benefit of tools which could automatically study outage requests for resources classed as low utilization and low consequence outside of the periods when they are known to be needed. The tool should also update the studies as new information becomes available that may impact the outage decision. As the number of these types of devices increase in a system, managing the routine study work would alleviate a burden on the operational planning engineering staff.

3.8 Proposed Actions

From the perspective of a reliability coordinator, a number of conditions must be checked in advance of granting an outage request to a generation or transmission facility. Table 3-1, below, attempts to match each of the proposed enhancements to the outage scheduling process with the key beneficiaries from its adoption (higher number of stars indicates larger benefit). These analyses will be influenced by the same emerging factors (Renewables, HVDC, etc.) that are listed previously in this section. Where these processes exist already, they will have to evolve to meet the needs of the system in the future. In general, reliability evaluations will need to consider a wider range of resources providing extended support to the system through ancillary services or mandated capabilities.

[1] Also known as SIPS – System Integrity Protection Scheme (IEEE)

Processes will also need to include a more probabilistic approach, given the uncertainties surrounding renewable production, demand and forced outages and planned outage durations.

Based on interactions with a range of entities responsible for various parts of the outage planning process, this document has attempted to summarise the potential areas for development in the functions listed above. The table below attempts to match each of the proposed enhancements to the outage scheduling process with the key beneficiaries from its adoption (higher number of stars indicates larger benefit). The next step in this project is to identify one area in which the most immediate value is perceived by EPRI members and to commence algorithm development in this area. Feedback on the topics listed above is sought and welcome as the project evolves.

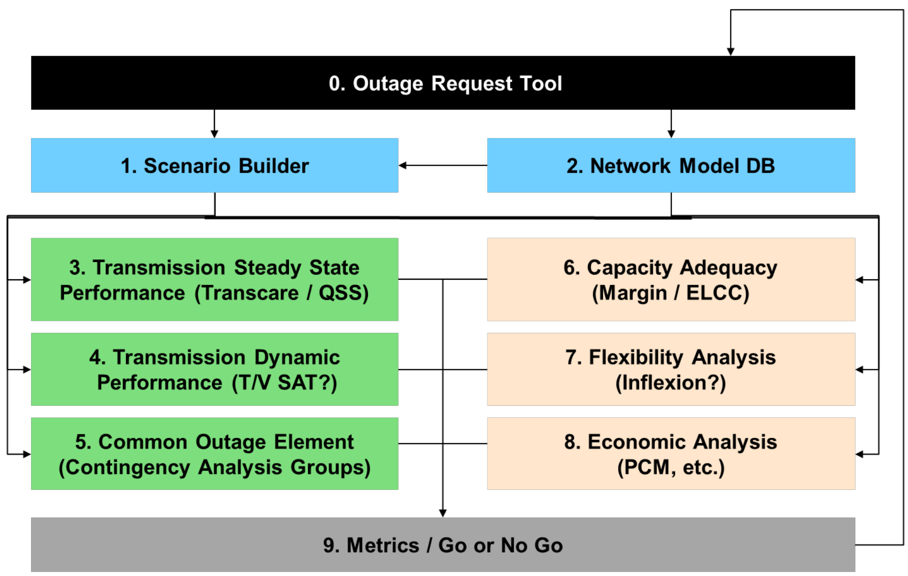

Figure 3-1
Outage request assessment process

Table 3-1
Potential solutions for future outage scheduling and value to each function in the outage plannign processthe key beneficiaries

Process Enhancements	ISOs / Reliability Coordinators			Transmission Owners	Generation Owners
Concern	**Transmission Capacity**	**Generation Capacity**	**Flexibility**	**Outage Permission**	**Risk minimization**
Coordinated Outages	★★★	★★	★★	★★★	★★
Renewables – risk based planning principles	★★★	★★★	★	★★	★★
Renewables – risk based generation outage planning	★★	★★★	★★★	★	★★★
Embedded HVDC modeling	★★	★★	★★	★	★
RAS/SPS modeling	★★	★	★	★★	★
Dynamic line rating	★★	★★	★	★★	★★
Low utilization resources	★★★	★	★	★★	★

Section 4: References

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