Smart Solutions, Real Results

Prepared for:

Western Interstate Energy Board and the

State-Provincial Steering Committee

04/24/2015

New Methodology for Determining the Transfer Capability of the Western Grid – Final Report

Prepared by:
Quanta Technology, LLC
4020 Westchase Boulevard, Suite 300
Raleigh, NC 27607

Contacts:
Ali Daneshpooy
ADaneshpooy@Quanta-Technology.com
(510) 272-2790

Rahul Anilkumar
RAnilkumar@Quanta-Technology.com
(510) 272-2796

Acknowledgment: "This material is based upon work supported by the Department of Energy National Energy Technology Laboratory under Award Number(s) DE-OE0000422."

ACKNOWLEDGMENTS

Quanta Technology would like to thank the following individuals and the WIEB Path Rating Advisory Team for providing valuable insights, advice and feedback on the Path Transfer methodology.

- Doug Larson, Senior Advisor, Western Interstate Energy Board
- Maury Galbraith, Executive Director, Western Interstate Energy Board
- Tim Mason, Grid Subject Matter Experts LLC
- Vic Howell, Engineering Manager, Peak Reliability Council
- Philip Jones, Commissioner, Washington Utilities and Transportation Commission
- Andrew Mills, Researcher, Lawrence Berkeley Nation Laboratory
- Nathan Powell, Manager of Planning Services, WECC
- John Savage, Director, Utility Program, Oregon Public Utility Commission
- Dede Subakti, Director of Engineering, California Independent System Operator
- Chifong Thomas, Director, Transmission Planning and Strategy, Smart Wire Grid

GLOSSARY OF ACRONYMS

- BES -- Bulk Electric System
- COI – California-Oregon Intertie Transmission Path
- EIM – California Independent System Operator Energy Imbalance Market
- FASTC – Flexible, Adaptable, Scalable Transmission Capability
- FACTS - Flexible Alternating Current Transmission System device
- IROL - Interregional Operating Limits
- NERC - North American Electric Reliability Council
- PMU - Phasor Measurement Unit or "Synchrophasor"
- POTF – WECC Path Operator Task Force
- RAS – Remedial Action Schemes
- RC – PEAK Reliability Coordinator
- SCADA – Supervisory Control and Data Acquisition system
- SOL - Seasonal Operating Limits (WECC) and System Operating Limits (NERC)
- SPSC—(WIEB) State Provincial Steering Committee
- TOP - Transmission Operator
- TTC – Total Transfer Capability
- WECC – Western Electricity Coordinating Council
- WIEB – Western Interstate Energy Board

TABLE OF CONTENTS

1. INTRODUCTION

A goal of the Western Interstate Energy Board (WIEB) and the WIEB's State Provincial Steering Committee (herein referred jointly to as "WIEB") is to improve the efficient use of the existing transmission grid in the Western Interconnect. To further this goal, in 2014 WIEB engaged Quanta Technology to develop a new methodology for determining the transfer capability[1] for transmission paths and lines included in the Western Interconnect bulk electric system (BES). Working with the WIEB Path Rating Advisory Team (established specifically for this project), Quanta developed a dynamic path rating methodology to better reflect the actual transfer capability of the lines during different time periods and system conditions, while maintaining the reliability and integrity of the bulk electric system to meet all North American Electric Reliability Council (NERC) requirements.

The benefits of a more robust transfer capability methodology include transfer capabilities based on more definite system conditions, increased reliability, increased intra- and interregional trading opportunities, and lower costs in both centralized markets and in bilateral markets by allowing additional lower cost generation to be delivered to consumers.

The Transfer Capability initiative focus is limited to the development and demonstration of a transfer capability methodology as an improvement to the current path rating process. Implementing this methodology in the Western Interconnect will require substantial revisions to the current Path Rating processes and practices, which are coordinated by the Western Energy Coordinating Council (WECC) and the Peak Reliability (Peak). This document is not intended to serve as an implementation roadmap, rather to present the new methodology.

1.1 Drivers for Developing a New Path Transfer Methodology

The primary drivers for the Transfer Capability initiative are to improve system reliability and accurately determine transfer capability ratings to meet changing grid needs and usage. In addition to these goals, WIEB endeavored to develop a methodology that utilizes all available grid information and considers emerging grid management technologies that could impact line ratings, and to promote consistency in the path rating methodology in the planning and operations time horizons, as well as in real-time operations. Finally, a goal was to design a

---

[1] Path transfer capability in the context of this report refers to the technical potential for the movement of power from one area to another over a specified set of transmission facilities, or paths, while meeting reliability standards. The units of transfer capability are in terms of electric power, expressed in megawatts (MW).

methodology that could reasonably be implemented by transmission owners and operators by 2020, hence would largely utilize existing information streams and technology.

Enhancing Reliability

The Western Electricity Coordinating Council (WECC) maintains processes for transmission owners to develop ratings for transmission paths in the Western Interconnection, while Peak Reliability (Peak) coordinates develops seasonal transfer capabilities for the paths. Recent failures of the bulk electric system (BES) highlight that the current processes are insufficient to meet the current and future requirements of the system. This failure was highlighted by the September 8, 2011 Southwest outage, where there was a massive cascading blackout despite the fact that all paths were operating within the prescribed limits. This concern was discussed by Gerry Cauley, CEO of the North American Electric Reliability Corporation, in a letter to WECC following the September 8, 2011 outage:

> NERC is pleased to see that WECC is holding additional discussions to clarify the role of Path Operators, including the potential to implement contractual relationships and make use of RTCA [Real Time Contingency Analysis] and other tools to improve the accuracy of system operating limits. As these discussions continue ***NERC suggests that you also review the concept of Path Ratings and whether, as the Western Interconnect has become more highly interconnected, the Path Rating and Path Operator concept, along with the use of nomograms, still has merit for real-time operations.*** Other interconnections do determine Flowgate limits for purposes of interchange scheduling, but rely more fully on RTCA for real-time operating reliability.

In response to the September, 2011 event the WECC convened the Path Operator Task Force to identify potential issues with the current process. The Task Force identified several specific concerns with the current process to determine and manage Path System Operating Limits in the operating horizon. [2]

---

[2] WECC's Path Operator Task Force concluded that:

1. The Path SOL (System Operating Limits) concept undermines the distinction between reliability limitations and commercial limitations
2. Path SOLs often do not take into consideration real-time tools and information
3. The Path SOL paradigm potentially disguises other critical limitations
4. The Path SOL paradigm results in "chasing the SOL"
5. The Path SOL paradigm results in unnecessary TOP and RC compliance risk
6. The Path SOL paradigm pre-supposes the need for unique monitoring of all WECC paths
7. The Path SOL concept is extraneous and redundant in light of the revised SOL Methodology

Finally, the current path ratings represent a mixture of technical capability and commercial interests. Long-term path ratings are proposed by transmission owners and are accepted upon completion of the WECC path rating process, with the ratings typically developed using a set of static scenarios that may not represent system conditions.

Develop Dynamic Transfer Capabilities to Reflect Transfer Opportunities

The uses of the transmission grid are changing, and with this is a need for more dynamic path transfer capability ratings. Historically, the paths were used to transmit large and generally predictable flows of energy. Increasingly there is a demand to use these paths to support variable amounts of generation, including the delivery of renewable generation and capturing all the benefits from interregional intra-hour energy markets (i.e., the California Independent System Operator Energy Imbalance Market).

A more real time accurate and dynamic path rating would better support these grid needs, and likely result in more available transfer capacity (ATC) during certain hours of the day or times of the year.

The current path rating process is believed to systemically understate transfer capability. The process results in the development of a single value (in most cases) to reflect transfer capability on a path for all hours, so this will by nature be a conservative value. In the planning horizon this value is the maximum Total Transfer Capability (TTC) rating, which represents the transfer capability at the time of peak path utilization during the year. Seasonally (or more frequently if system conditions warrant) the paths are re-assessed by the path Transmission Operator (TOP) to determine whether the transfer capability may be maintained or need to be revised downward. These Seasonal Operating Limits (SOL) are the *lesser of* the TTC or the re-assessment analysis. These SOLs are used in real-time operation even if the real-time conditions on the grid would support greater transfers.

Utilize All Available Information and Incorporate New Technologies

Technology is enabling more precise methods to develop and maintain path ratings. New technologies, such as Phasor Measurement Units (PMU) and Distributed Flexible Alternating Current Transmission System (D-FACTS) are being implemented on the transmission system

---

8. TOP designated as the Path Operator may have limited ability to manage Path SOL exceedances
9. The Path Operations paradigm prevents full utilization of transmission and generation investments

that allow for substantially more granular information on path flows, and offer the ability to better manage transmission flows than was historically possible. Further, advances in computing capacity will enable grid planners, managers and operators with the tools necessary to process all of this information. To date, path ratings have been a slow and labor-intensive process. Advanced algorithms allow for the automation of many manual processes (such as scenario-development), and distributed computing will minimize the new computing capacity that will be required to develop the path ratings.

Consistency in Rating Process

A concern with the current process is the potential lack of consistency in path rating processes among transmission owners and operators. The NERC and WECC both provide requirements and guidelines regarding path rating, but leave the rating analysis up to the individual path and line owners and transmission operators. Rating for the paths have been determined over a period of time, using a variety of assumptions and methodologies. There is no formal Interconnection-wide process to ensure the assumptions and study tools used in one path rating are consistent with those used by another path rating process. Similarly, it is the Path Operators that are responsible for developing Seasonal Operating Limits. The Path Operators will conduct analyses using their own scenarios, but this is no formal coordinated with other path operators in the system.

1.2 Study Tasks

The Transfer Capability study included a number of tasks designed to assess issues with the current process and develop a process to resolve those issues and develop a dynamic path rating methodology. The specific tasks addressed by Quanta include:

- *Review of current WECC path rating process and trends in path rating processes.* Perform a review of current WECC path rating processes and identify bottlenecks. This review is extended to new and current technologies deployable over a five year strategy that can find application in total path transfer calculations.
- *Develop a scalable, flexible and adaptable new methodology to assess path transfer capability for the Western Interconnection.* Develop a methodology that takes into consideration new technologies deployable over a five year implementation strategy. This includes a description of the methodology and the analytical processes involved.
- *Extend methodology to different sub annual periods for determining transfer capability values.* Extend the methodology to all horizons or sub annual periods by determining the data requirements for each period. The considered sub annual periods include real

time, day ahead, week ahead, month ahead, seasonal and long term planning, in compliance with NERC MOD standards.

- *Develop a flowchart of the methodology.* Develop a flow chart depicting the detailed methodology with sequential activities and analytical processes to develop the path transfer capability values.
- *Detail how the new path transfer capability methodology differs from existing path rating methodology.* Highlight the key differences between current WECC path rating process and the proposed methodology. This stage includes identification of metrics to calibrate differences between the two processes.
- *Conduct an example of a path transfer capability assessment using the proposed methodology.* Conduct an example of a path transfer capability calculation using the proposed methodology in comparison to the existing WECC path rating methodology. This assessment was performed on a WECC rated path under an identical set of assumptions for both considered methodologies.
- *Identify technical hurdles and data access requirements to be resolved in order to implement the proposed methodology.* Identify the technical hurdles and data access requirements in order to implement the proposed methodology. This evaluation includes the type of technology demands, and a high level estimate of the cost for tools to implement the proposed methodology.

1.3 Report Organization

The report is organized into the following sections based on the study objectives.

Section 2 – Review of Path Rating Processes. This section reviews current WECC path rating processes and identifies bottlenecks. This review is extended to new and current technologies deployable over a five year strategy that can find application in total path transfer calculations.

Section 3– Emerging Technologies, Models and Tools. This section includes a discussion of relevant existing and emerging technologies that find application in determining total path transfer capability. A high level discussion of the current status of the technology is also made.

Section 4– Flexible, Adaptable, and Scalable Path Transfer Capability (FASTC) – This section includes a discussion of the proposed methodology. It is discussed in two sub sections where one provides a high level discussion of the process, and is followed by a technical discussion of the process. This section includes a detailed description of the analytical processes and a sequential flowchart of the process. A discussion is also made about how its application to different sub-annual calculation periods.

Section 5 – Comparison to Existing Process – In this section metrics have been considered to compare the existing WECC process against the proposed methodology. This is concluded by a sample demonstration of the methodology against WECC current methodology.

Section 6 – Technical Hurdles and Data Access Requirements – In this section, the technical hurdles, data access, modeling challenges are brought to light. All discussions are relevant to consideration of a five-year deployment strategy. This section also includes information of a high level cost estimate for implementation.

References to figures, and technical material can be found in Appendix B.

2 REVIEW OF PATH RATING PROCESSES

Path rating processes are generally coordinated by regional NERC regional coordinating councils, but the specifics of the processes will depend on individual transmission owners and path operators. NERC MOD-001 requires each Transmission Operator (TOP) to calculate Total Transfer Capability (TTC) and Available Transfer capability (ATC) using one of the methodologies listed in MOD – 028/029/030. Different methods the transmission operator may use to identify TTC include:

- Based on satisfying all criteria including all elements at or below 100% of their continuous rating, demonstrated stability during post contingency with all elements under emergency rating, no uncontrolled separation
- By contract rights
- Nomograms
- Through determination of how to resolve an adverse impact on existing path
- Historical precedence

The WECC path transfer capability is calculated in the Operating and Planning Horizon timeframes, detailed below. Following the discussion of the current WECC process is a discussion of selected alternative methods that other coordinating councils are currently implementing.

2.1 WECC Path Transfer Capability Rating Process

Currently, the determination of transfer capability in the Western Interconnection occurs in three different time frames: the planning horizon, the Operating Horizon, and Real-time. A summary of these timelines is depicted in Figure 1, followed by a discussion of the activities included in the different time frames.

TIMEFRAME	**>1 Year**	**<1 year to Day-ahead**	**Real-time**
WHAT	Establish Path Rating	Establish Seasonal Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL)	Enforces Path Rating – monitors path flows and mitigates as needed
WHO	Transmission Facility Owners & WECC Project Review Group	Path Operator and affected systems group	Path Operators
USES	Transmission expansion planning, long term commitments	Establish Path Transfer capability to respond to near-term conditions (i.e. hydro and generation outages)	Maintains reliability
HOW	Calculated using long-term planning assumptions	Calculated using planning assumptions with known changes	Path limit - the lesser of path rating
WHEN REVISED	Not revised unless need arises, or requested by path owners	Seasonal, and as needed to reflect expected operating conditions.	As needed to reflect current operating conditions

Figure 1: Path Ratings by Timeframe

Planning Horizon

The commonly referred to “path rating” is established in the Planning Horizon. This is typically the initial rating for a transmission path and these values tend to be static for years unless reinitiated by a path owner or there are substantial modifications to the path. To establish path ratings for planned new facility additions and upgrades, WECC uses a three-phase study and coordination process to develop maximum transfer capability, referred to as the WECC Path Rating process. This process is designed for project sponsors to attain an Accepted Rating and demonstrate how their project will meet NERC reliability standards and WECC criteria. It also provides a process to communicate to other transmission operators how the new facilities, upgrades or new path rating would impact system operations when they come on line. It requires coordination through a review group comprised of project sponsors and representatives of the other systems that may be affected by the project. The process includes:

- **Phase 1** is conducted by the project sponsor and is initiated when the project sponsor submits a report through the WECC Progress Report process or when a formal letter of notification is provided to the Planning Coordination Committee (PCC) and Technical Studies Subcommittee (TSS). It is during Phase 1 that the project sponsor conducts sufficient studies to demonstrate the proposed non-simultaneous rating of the path associated with the project and document study results in the Comprehensive Progress Report. Known simultaneous relationships should also be addressed in the accompanying report. Some Phase 1 studies are also coordinated through sub regional planning groups. Phase 1 is completed when the Comprehensive Progress report has been accepted by TSS and a planned rating is associated with the path.
- **Phase 2** includes a review of the Project Plans of Service by a Project Review Group (PRG) that is comprised of WECC members. During this phase, the projects planned rating is validated. The simultaneous Transfer Capability effects and the impact of the Project on neighbor transmission systems are studied. The project sponsor and PRG document their findings in the Project Review Group Phase 2 Rating Report. Phase 2 is completed when the Phase 2 Rating Report is accepted by PCC and the Path associated with the project is granted an “Accepted Rating”.
- **Phase 3** is the monitoring phase where major changes in assumptions and conditions are evaluated to ensure the “Accepted Rating” is maintainable. Phase 3 is complete when the Project is placed into service.

A summary of the entire sequence of Project Coordination and Path Rating processes is provided in Figure 2.

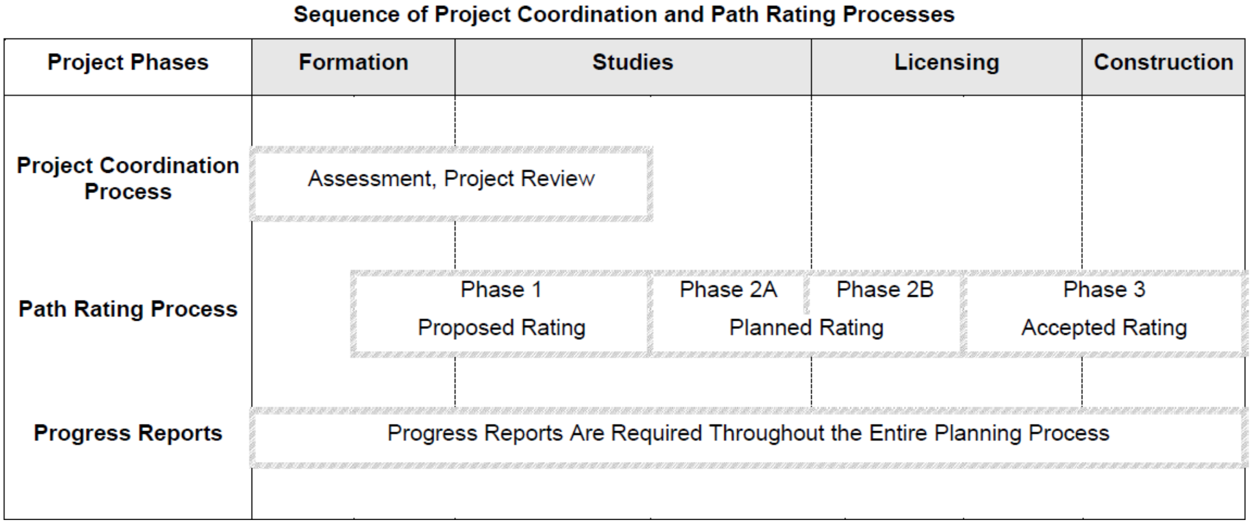


Figure 2: Project Coordination and Path Rating Processes

Operating Horizon

The Operating Horizon refers to the period between day-ahead of the operating day and extend to one-year ahead of the operating day. Within the operating horizon, path operators conduct seasonal System Operating Limit (SOL) analysis (with input from potentially affected facility owners) based on expected system operating conditions and updated operating assumptions. SOL analyses are generally conducted for each peak operating season but may be conducted more frequently if conditions require.

The SOL may either confirm the path rating established in the Planning Horizon or result in a new, more restrictive transfer capability rating. Going into real-time the SOL will always be the *lesser of* the SOL rating or the Planning Horizon path rating.

Real-time

There is no path rating process, per se, in real-time. Noted above, the path rating going into real-time is the lesser of the Planning Horizon path rating or the SOL rating. The Transmission Operator may further restrict the path rating if operating conditions require.

Potential Revisions to WECC Path Rating Process

Noted in Section 1.1 above, the WECC convened a task force to identify potential issues and make recommendations regarding path operations and the use of path SOLs in real time operations. The 2014 POTF White Paper entitled *"A New Paradigm for Path Operations"* proposed eliminating the Path SOL. In this paradigm, transfer analysis studies are conducted ahead of time to determine the Path TTC and determine existence of stability limits. The path no longer has an SOL. Instead, a TTC is established for the path and the individual path elements, along with the entire BES, are monitored as SOLs. The path operator role is hence eliminated with all responsibilities in the hands of TOPs. Under the proposed paradigm, TTC's are not real time operating parameters; however, SOLs are real time operating parameters.

In February 2015 WECC announced the creation of a Path Operator Implementation Team to "facilitate the implementation of the POTF recommendations." The Implementation team has hosted its first meeting but detailed implementation plans have not been announced.

2.2 Changing Paradigms in Determining Path Transfer Capability

Nationally, several grid operating entities are taking initiatives to make their TTC calculation process dynamic in nature. Their strategies include a combination of commercially available technologies and tools, thereby making their processes more efficient and far less expensive.

ISO New England has automated their TTC calculation process and is in the process of moving them from factory testing (parameter tuning and observations) to the day-ahead and real-time markets. This automation allows for online estimation of the power system transfer capability based on steady state and voltage stability, coordinated with security monitoring. The software utilizes State Estimator (SE) and Synchrophasor PMU data sets for determining the total path transfer capability under normal and contingency conditions. The PMU measurements are also used to monitor current system operating conditions.

Hydro- Quebec has implemented a hybrid real time and planning based TTC calculation process. Synchrophasor data is used in the process of reliability monitoring and developing systematic guidelines that compare phase angles against actual transfer limits across interfaces (baselining). They take into consideration steady state, voltage, and dynamic system stability. Their use of real time TTC has not been reported. Their processes take advantage of internally developed software tools that work in combination with commercially available software. Hydro-Quebec's baselining process includes the following activities:

- Building nomograms using PMU and State estimator phase angle data.
- Setting appropriate values for security monitoring and alarms.
- Establishing predictive models to compute precursors to significant operational issues and abnormal behaviors.

BC Hydro initiated “Online TTC” project to define, design and develop a more accurate TTC calculator in real time and near real time environment. Their methodology includes a combination of online system stability assessment tools and probabilistic Transmission Reliability Margin (TRM) computations. It has been developed as a customized application on the Energy Management System (EMS) .The calculator is currently under Factory Acceptance testing.

3 EMERGING TECHNOLOGIES, DATA AND TOOLS

There are a variety of new technologies that are currently being deployed on the power grid, which offer the promise of substantially improving the data available on grid operations, as well as technologies to allow for better management of power flows. While these technologies have found applications in some areas of power grid management, their benefit to improving transfer limits has yet to be fully realized.

In this section, emerging technologies that are applicable to path transfer calculations are discussed. The discussion serves as an introduction and precursor to the discussion of the proposed methodology in Section 4. While most of these technologies are commercial with various level of penetration on the grid currently, we anticipate they will be substantially more prevalent within five years.

3.1 Phasor Measurement Units

Phasor Measurements Units (“PMU” or “Synchrophasor”) are electronic devices capable of measuring real time system data including phase angles. The initial use for these devices was improved grid visibility to reliability events; however, they have the ability to significantly improve operator tools. They provide additional control opportunities in WAMPAC (Wide Area Measurement, Protection and Control) environments by directing relays in special protections schemes.

PMU technology supports the ability to develop dynamic total path transfer capability. With faster data transfer rate (in the range of milliseconds), they allow for an environment where continuous monitoring and dynamic calculations can go hand-in-hand. Taking advantage of large data availability, data analytics and commercial processors and tools, the transfer capability between two areas can be computed in real time/near real time. PMU data availability also provides great opportunity in improving accuracy of path transfer calculations in the long term planning horizons.

In the future, as new technologies that can handle PMU- like capabilities are deployed, the capability can be expanded throughout the system. For example- some D-FACTS devices already have the capability of sensing and communicating the system conditions to a central location. As these devices become more prevalent, the visibility of the system can be further improved.

There are many PMU deployments in North America. DOE funding and the Western Interconnection Synchrophasor Project (WISP) supported large-scale deployment of PMUs in the Western Interconnect. The PMU deployment and data flows in the North American power grid as of March 25, 2014, are shown in Figure 3. Figure 4 lists the total PMU installations made at WISP participating entity locations.

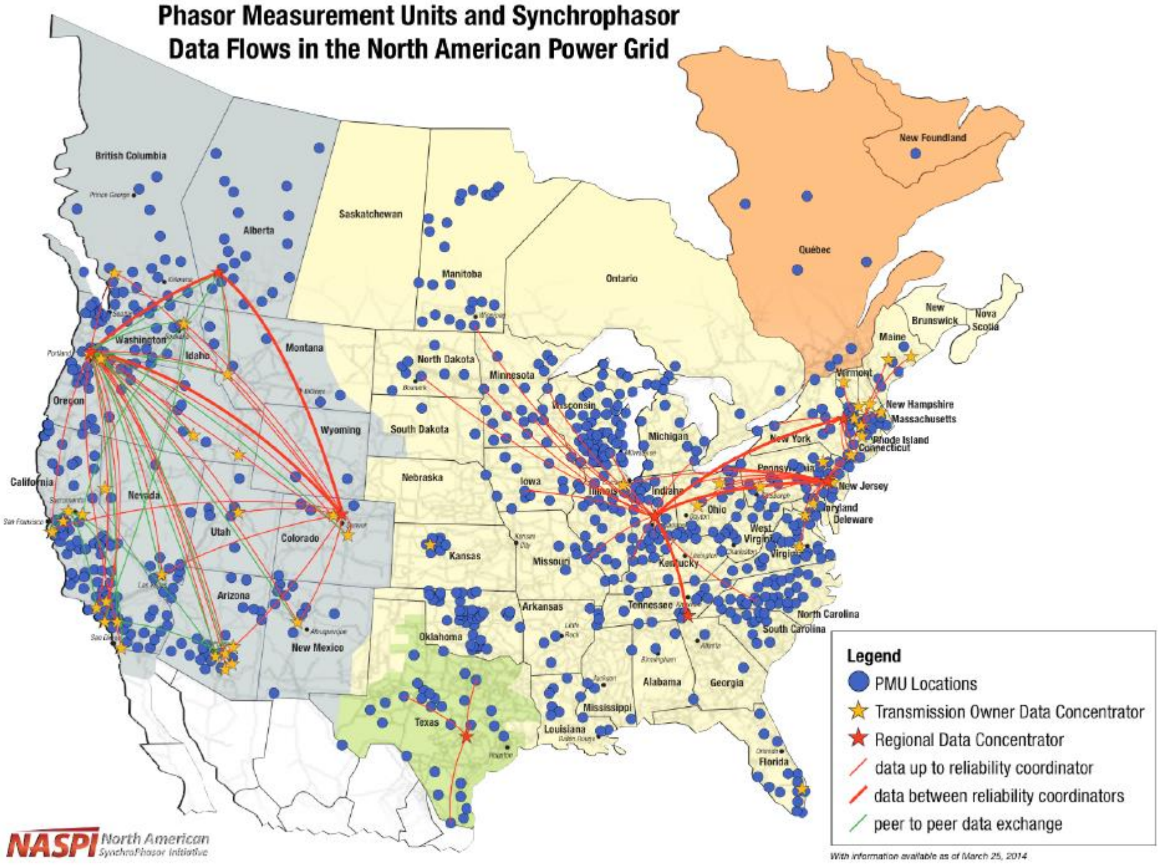


Figure 3 : PMU Installations in Northern America (As of March 25, 2014)

WISP Participants	Total PMU Installed
Bonneville Power Administration	128
Idaho Power Corporation	14
NV Energy	18
Pacific Gas & Electric	194
PacifiCorp	5
Salt River Project	42
Southern California Edison	62

Figure 4: PMU installations among WISP Participants.

3.2 State Estimators

Dynamic State Estimators are another technology that will enable more dynamic transfer limit calculations. State Estimators (SE) are part of all Energy Management Systems (EMS) used in transmission control centers around the world. They take advantage of measurements on the field to provide an estimate of the current operating state of the power grid. They are important components in providing "visibility" to the entire power system at any instant in time. Original estimations were dependent only on "slower refresh rate" SCADA measurements, a trend that is changing with the availability of Synchrophasor data. The state estimation outputs include voltages and phase angles at all substation buses in the network.

State estimator technology and their refresh rate are key drivers in dynamic path transfer computations. An entire system model or reduced network model of the system is used in the state estimator. The robustness of these models will have an impact on the accuracy of the results. By placing PMU units at critical substations or "buses" in the network, the estimation processes provide complete visibility to the system model. These measurements are then used to make total path transfer computations in real time/near real time

Current state estimators are mostly static in nature, wherein they use SCADA based measurements or a combination of SCADA and PMU (Hybrid) measurements. The evolving trend is to move towards PMU (or PMU- like capability device) only state estimators, which can make the entire estimation process far more dynamic. Dynamic State estimators allow for improved accuracy, faster speed of estimation, and increased visibility to more states of the power grid like equipment (generators, control device) dynamics. Dynamic State estimation is a new technology considered within reach of a five year deployment strategy.

Figure 5 shows some of the commercially available state estimator (EMS) technology manufacturers and their client installation locations. The discussed manufacturers provide SE solutions that take PMU measurements into consideration.

Client	EMS Manufacturer
Bonneville Power Administration	OSI Sift PI, Alstom Grid
California ISO	EPG RTDMS
Peak RC	Alstom Grid
PG & E	Alstom Grid
SCE	General Electric (GE)
SDGE	EPG RTDMS

Figure 5 : EMS Manufacturers and Client installation locations

3.3 Real Time/ Planning Path Transfer Calculation Tool

Transfer flow studies are generally performed in the planning horizon to calculate the total path transfer capability between participating areas. Almost all commercial planning tools have the capability of performing these studies. The result of planning based TTC values do not depict current operating states of the system. In other words, system conditions may change in real time, which can make those planning assumptions more or less conservative.

Most of these offline tools are now capable of online deployment. By using state estimator results and network models, they can perform transfer calculations online, only limited by the capabilities of commercial computing power. Current practices make use of continuation power flow or repeated power flow techniques where the transfer size is incremented in the direction of loading/generation variation in a fixed iterative manner.

New advances in tools allow for these transfer size increments to be varied adaptively based on prediction to boundary of instability. Based on response of previous step size, the next will be adjusted taking into account last updated transfer solution. This technology is slowly gaining popularity in all online deployment tools. Further advantages include reduced computational effort and faster solution time.

3.4 Contingency Screening and Analysis

Online contingency analysis (OCA) tools take advantage of state estimation results and EMS network models to identify the most limiting elements in the network at a given instant in time to ensure N-1 security. They are run in coordination with the state estimator solution and have already been largely deployed on a commercial scale within the Western Interconnection.

Current deployment strategies include running the OCA for a pre-defined set of identified/pre-screened contingencies based on operator experience or planning recommendations. Owing to the dynamic behavior of the power grid, wherein the same set of contingencies could have more severe or less severe effects depending on system dynamics, demand a more automatic contingency screening approach. Furthering this cause, is the fact that additional renewable penetration, EIM markets and traditional generation retirements, can lead to larger magnitude of changes in grid conditions. These might go unobserved if the list of online screening contingencies are not manually updated when there are significant changes in system operating conditions.

Advances in this domain use optimization algorithms to identify the most critical contingencies in the network using the state estimator model and current operating state of the system. These technologies are also becoming available in commercial tools nowadays.

3.5 Dynamic Security Assessment (DSA)

Dynamic Security Assessment is a subject of great interest owing to recent blackouts. There is substantial interest by grid managers to move the processes of stability assessment to the real time or near real time environment.

System stability assessments are currently carried out in an offline environment. While the speed of offline computations have been considerably increased, commercial tools also allow for these processes to be deployed online and work in coordination with the State Estimator and OCA tools. At every transfer level, and the critical contingencies considered, the dynamic security assessment is carried out until the most limiting constraint is identified that impacts the total path transfer. This tool is also a very critical component of dynamic TTC calculations. While commercial EMS packages include DSA algorithms, there is no official report of them being used in path transfer determination.

3.6 Look Ahead Calculators

In accordance with NERC MOD Standards, path transfer calculations must be posted for periods into the future including hour ahead, day ahead and week ahead. Look ahead calculators are therefore used to compute the path transfer at periods in the forward operational horizon. They take into account scheduled generation changes, load forecast data, and expected changes in system operating conditions.

Currently, the process remains manual where planning based models are used to make these calculations. Owing to the available tools and technologies discussed earlier, these computations can also be made in an online environment using most current system operating states, updated to reflect future assumptions. This reduces the number of uncertainties in assumptions used for forward path transfer computations. Future work is this direction which may exceed a five year deployment range include improving computational effectiveness by using advanced prediction algorithms to margins of instability.

3.7 Volt/VAr Optimization and Control

The advent of PMU technology and commercial online tools has propelled research in the direction of Wide Area Management, Protection and Control (WAMPAC). Advanced technologies like FACTS devices and their control fall within the realm of WAMPAC. These devices provide dynamic voltage stability, grid stability and increased power flow capabilities to the existing transmission system. Some of these devices include, Static VAr compensators (SVC) used to provide voltage support, and Static Series Synchronous Compensators (SSSC) that can be used to increased power flow along a particular line.

Current practices are limited by restricted control over these devices and inability to dynamically optimize them in wide area model systems, to meet a common objective. From the perspective of path transfer calculations, a future with WAMPAC enabled control will allow for optimization of these devices in the state estimator network model to increase transfers along particular paths by controlling device settings.

3.8 Dynamic Remedial Action Schemes

Remedial Action Schemes (RAS) are used for emergency control to mitigate instability problems following the loss of one or more transmission lines on a path to prevent the system from out of step conditions that may result in cascading system wide outages. Existing RAS limitations are defined by growth of intermittent renewable generation and load mutability. Currently, RAS schemes monitor load flows on critical transmission lines, detect outage events, take pre planned mitigation actions against generator tripping and load shedding while signaling system operators. They are armed by transmission line load flow and triggered by transmission line status. Currently they are pre- set according to a large number of off line scenario simulations.

Path transfer calculations are largely dependent on armed RAS schemes. This is largely due to the fact that path transfers are calculated for limiting element system conditions. These critical loss conditions trigger RAS control actions that include load shedding, series/shunt device insertion, generation tripping, line switching etc. that can have an impact on path transfer.

Owing to advances in Synchrophasor technology, and WAMPAC enabled control, Dynamic RAS is capable of updating RAS control actions based on the system operating condition and system configuration. These can be updated in real time and more effectively improve reliability and path transfer capacity. Current commercially available planning tools can identify and propose RAS Schemes or optimal mitigation strategies that can meet the objectives of increasing path transfer while maintaining improved reliability.

3.9 Planning Model System Topology Representation

Current planning models are based on bus-branch representation of substations, while commercial EMS network models include node breaker representation. These differences will be further highlighted in upcoming sections of the report.

Node breaker models allow for improved accuracy by bringing the planning or seasonal horizon models closer to real time models. RAS schemes can be modeled with improved accuracy owing to node breaker representations that improve visibility of substation configurations. The impact of RAS schemes on path transfer calculation has been discussed.

Commercial planning tools include node-breaker representation of system components.

3.10 Model Validation

Model validation is important from the perspective of improving dynamics of components in planning models. The availability of larger PMU data for smaller time stamps allow for post disturbance analysis and parameter tuning.

While path transfer computations are largely dependent on planning models, the improved accuracy of dynamic models can capture network fast changing dynamics. This will help bridge the gap between black box proprietary manufacturer models and public domain models commonly used for path transfer studies.

Currently, most commercial software tools include model validation algorithms. However, the process of tuning each model parameter still remains largely manual, where each one is selected and varied within a pre-specified range. While considering the large numbers of models in the scale of the Western Interconnection, faster tuning is the need of the hour through parameter sensitivity analysis.

3.11 Load Forecast Data

Load forecasts are currently aggregated/predicted on a zonal or area wide basis. This data is provided by Load Balancing Authorities and reliability coordinators while taking into account schemes like demand response, distributed generation, energy efficiency programs etc.

The widespread deployment of smart meters allow for more granular and detailed load forecasts to be developed. Within the realm of path transfer calculations, improved forecast data can be used to improve accuracy of operational look ahead calculations, and forecast data in long term planning models by allowing for better prediction of load levels down to the loading of each individual line.

4 FLEXIBLE, ADAPTABLE, SCALABLE TRANSFER CAPABILITY CALCULATION

The proposed Flexible, Adaptable, Scalable Transmission Capability (FASTC) methodology is designed to work in all timeframes from long-term planning through the operating time horizon and real-time. It is designed to incorporate as much– or as little – information as is available regarding the path operation and control devices on the path. The results of the methodology are a physics-based line rating that meets all NERC defined reliability criteria.

The new methodology is flexible, adaptable and scalable to multiple platforms.

- Flexible: The proposed methodology can use current hybrid measurement data to estimate the operating state of the grid (State Estimation) at slower refresh rates or move to faster Synchrophasor data only State Estimation.
- Adaptable: Additional components can be added or subtracted as needed and as data allows. For example, Volt/VAr control from renewable generation units can be considered. System dynamic stability can be either calculated (current method) or be replaced with predictive estimations based on advanced algorithms.
- Scalable: The system may be used with the level of detail available to the operator. Load Forecast data can be replaced with aggregated Advanced Metering Infrastructure (AMI) data at a substation bus.

We begin with a discussion of the timeframes for the proposed path rating methodology. This is followed by a discussion of the components required for each timeframe.

4.1 Path Rating Timeframes

The FASTC methodology is designed to operate in two timeframes – the Operational Horizon and the Planning Horizon.

4.1.1 Operational Horizon

The Operational Horizon includes computing total path transfer capability for real time or near real-time (1-15 minutes), Day-ahead (1 hour to 24 hours ahead), and Week-ahead horizon (24 hours to 168 hours, 7 days ahead). The proposed methodology, if fully implemented online, can calculate TTC values for the Operational Horizon in 15-minute time intervals.

Figure 6 depicts the various components that are a part of operational horizon TTC calculations.

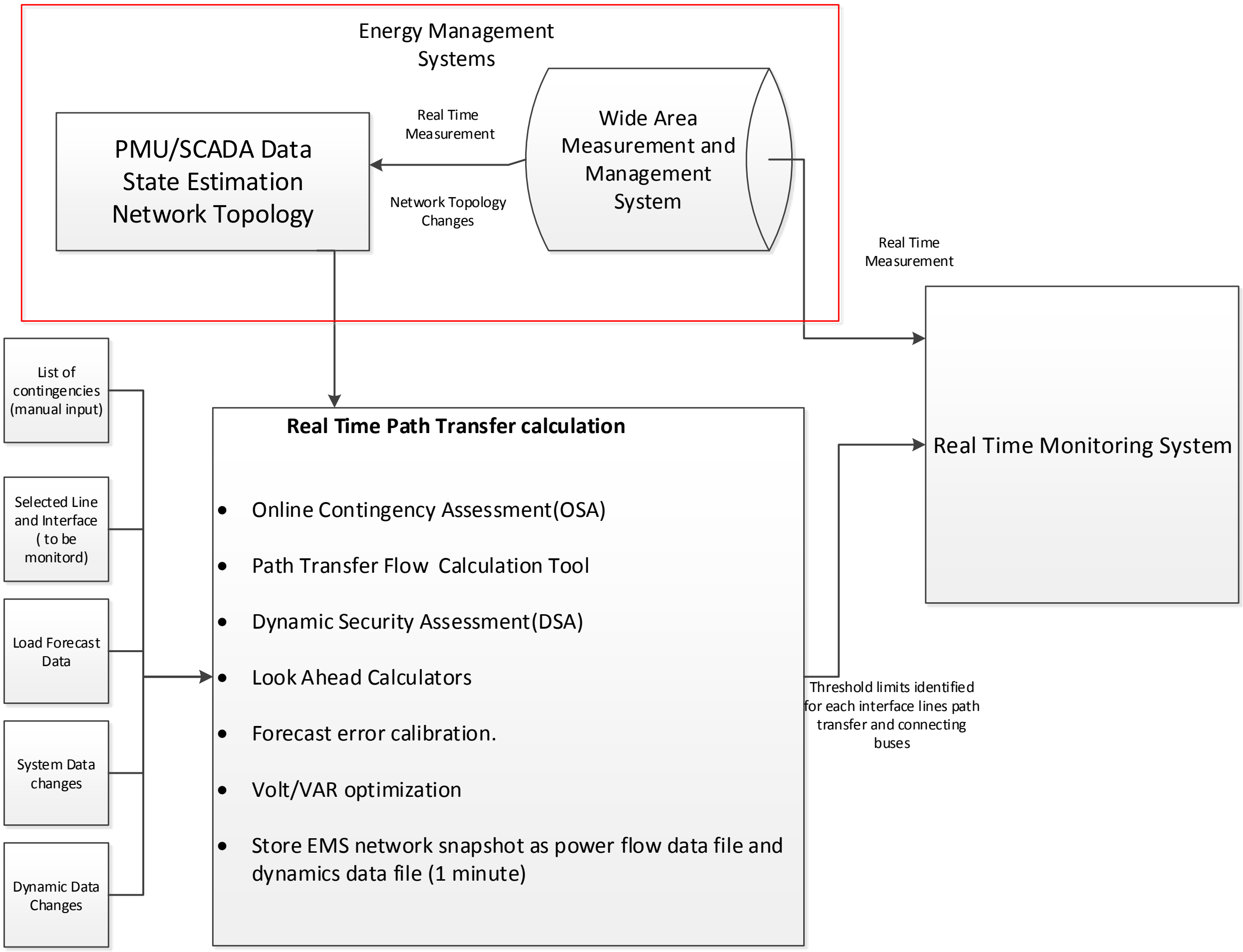


Figure 6 : Components in Operational Horizon.

4.1.2 Planning Horizon

Planning horizon include computing TTC for long-term planning (beyond one year ahead), seasonal assessments (1 to 12 months ahead of the operating period), and monthly assessments.

Figure 7 depicts the components used in the Planning Horizon TTC calculations.

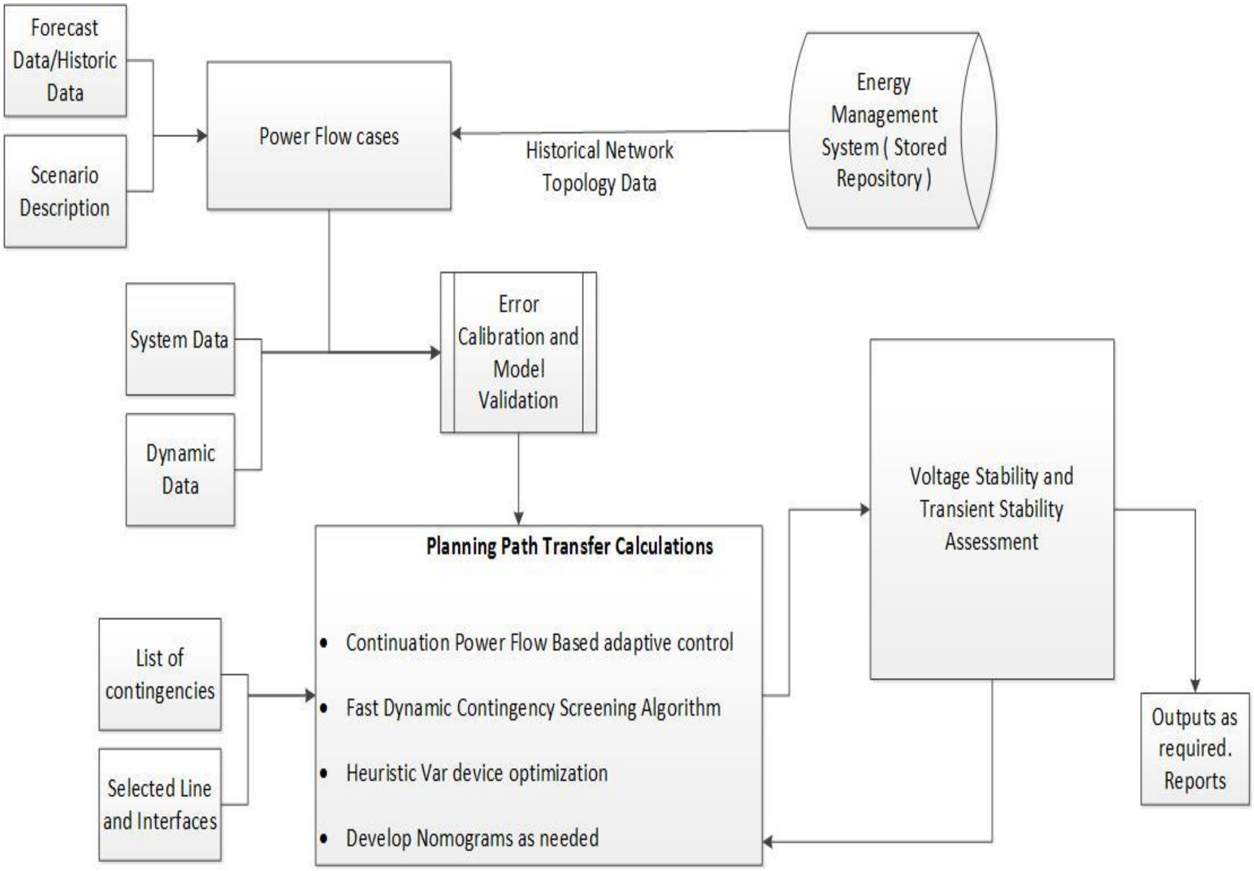
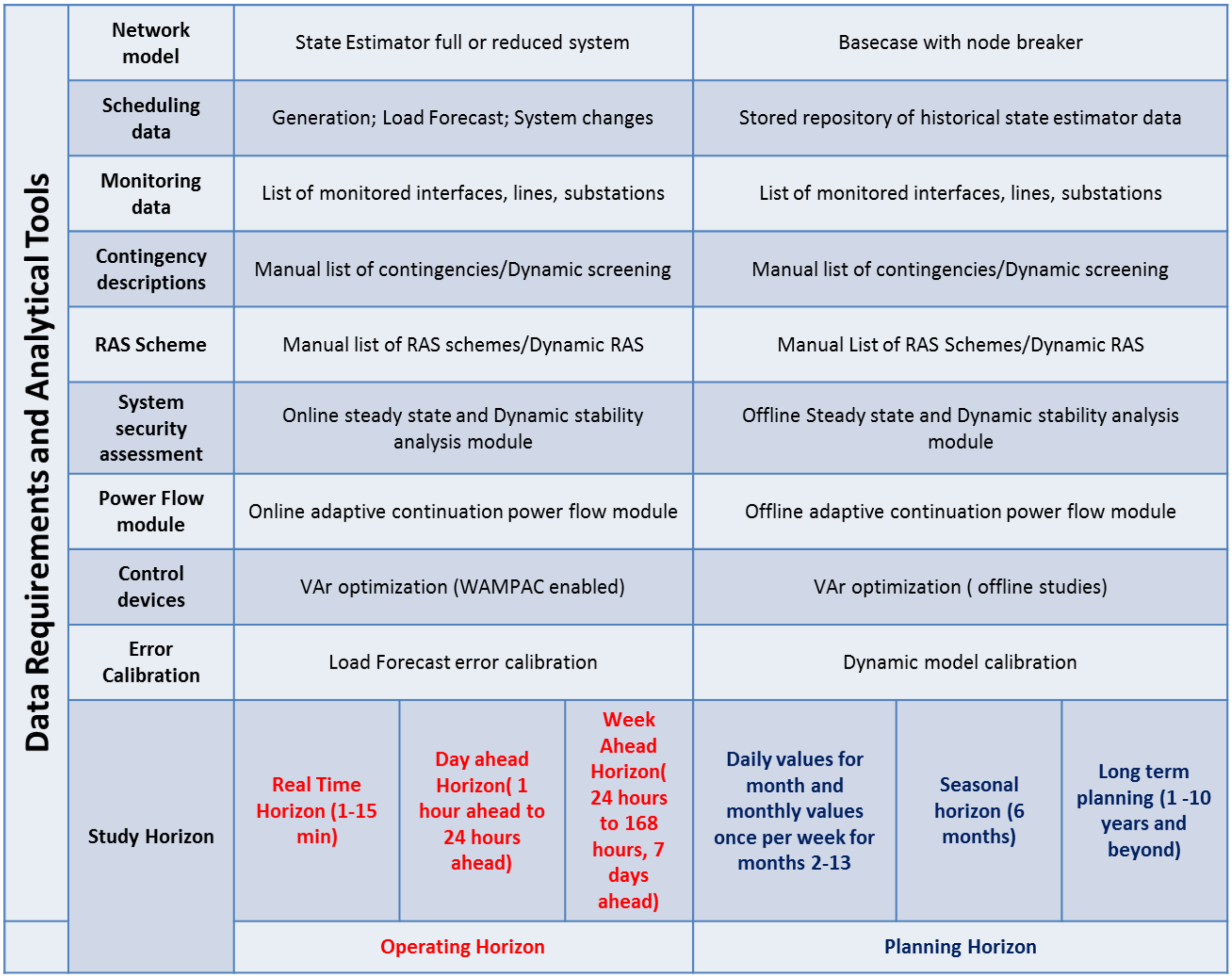


Figure 7 : Components involved in planning horizon

4.2 Data Requirements and Analytical Tools

The methodology will require a variety of tools and data for the determination of path ratings in the Operational and Planning Horizons. The requirements for these are summarized on Figure 8, followed by a discussion of each.



Data Requirements and Analytical Tools	**Network model**	State Estimator full or reduced system			Basecase with node breaker		
	Scheduling data	Generation; Load Forecast; System changes			Stored repository of historical state estimator data		
	Monitoring data	List of monitored interfaces, lines, substations			List of monitored interfaces, lines, substations		
	Contingency descriptions	Manual list of contingencies/Dynamic screening			Manual list of contingencies/Dynamic screening		
	RAS Scheme	Manual list of RAS schemes/Dynamic RAS			Manual List of RAS Schemes/Dynamic RAS		
	System security assessment	Online steady state and Dynamic stability analysis module			Offline Steady state and Dynamic stability analysis module		
	Power Flow module	Online adaptive continuation power flow module			Offline adaptive continuation power flow module		
	Control devices	VAr optimization (WAMPAC enabled)			VAr optimization (offline studies)		
	Error Calibration	Load Forecast error calibration			Dynamic model calibration		
	Study Horizon	**Real Time Horizon (1-15 min)**	**Day ahead Horizon(1 hour ahead to 24 hours ahead)**	**Week Ahead Horizon(24 hours to 168 hours, 7 days ahead)**	**Daily values for month and monthly values once per week for months 2-13**	**Seasonal horizon (6 months)**	**Long term planning (1 -10 years and beyond)**
		Operating Horizon			**Planning Horizon**		

Figure 8: Data Requirements and Analytical Tools for Path Rating Horizons

4.2.1 Operating Horizon Data and Tool Requirements

4.2.1.1 Energy Management Systems (EMS) and State Estimators (SE)

EMS systems form the backbone of operational horizon TTC calculations. They exist in all control centers around North America. Within their framework exist the state estimator and network topology model. PMU (Synchrophasors) and SCADA measurement data is processed within these systems. SCADA based measurement have a slower refresh rate of seconds to minutes, however availability of larger PMU data allows for more dynamic state estimation where measurements are obtained at the rate of 20-30 times per second. They are used as inputs to the state estimator module which provides visibility to the current operating state of the grid in an iterative manner. Transmission Operators use the results from state estimators for situational awareness and taking preventive action.

Current State Estimators are static in nature wherein they can use SCADA only or hybrid SCADA and PMU measurement. Future states estimators are proposed to be PMU only and dynamic in nature, wherein their outputs are not only voltage and phase angles, but also generator and control device states.

Working in coordination with the state estimators are the following –

- Bad Data Processors used to detect faulty measurements obtained from input PMU and analog SCADA field measurements. They also detect faulty estimates of State Estimator results.
- Topology Processors that include either reduced network models that only consider utility area or full network models that include all areas within the interconnection. The topology processors works in coordination with the bad data processor to make updates to topology based on errors identified through the estimation process.
- Network visibility check is a component where the given set of measurements and topology processor are checked to see whether they provide sufficient visibility to perform state estimation.
- Load Forecasts and Generation Schedules are used in instances where we need to borrow pseudo – measurements to make the network observable. They are also used for look ahead calculations where the network model might anticipate changes.

Figure 9 provides a high level overview of the components within the EMS module.

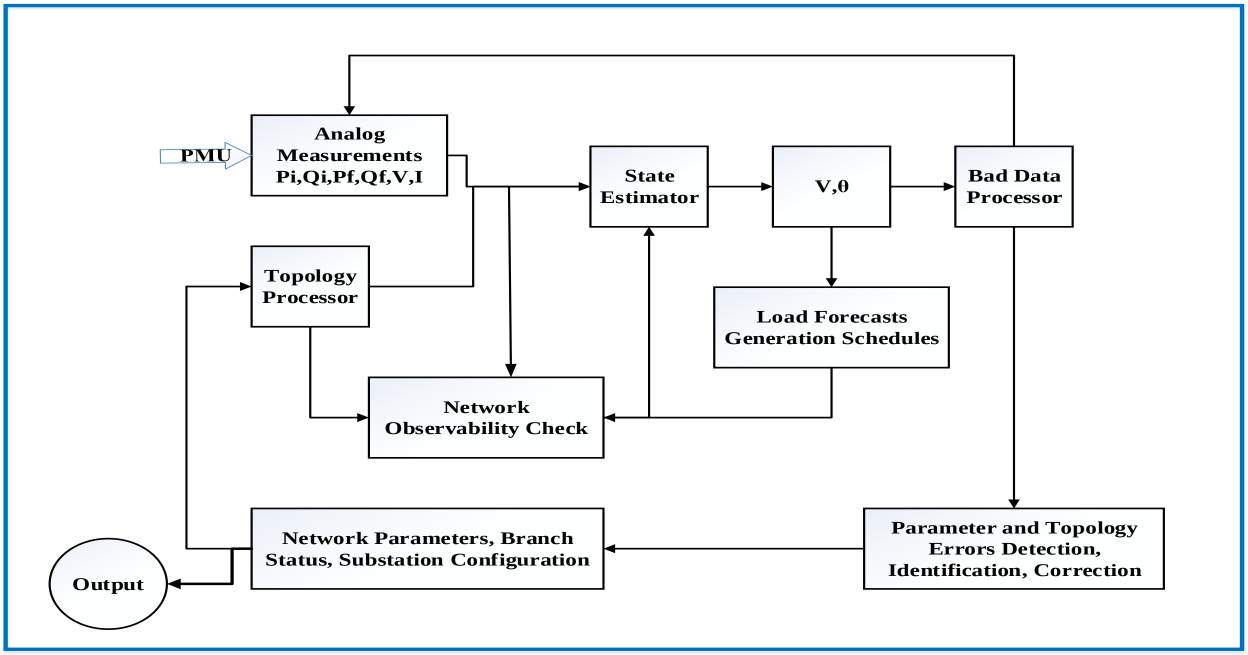


Figure 9 : High level overview of EMS and State Estimator module

The estimated or calculated states of the system (including voltages, phase angles and power flows), are used in Path Transfer computations.

Data from the state estimator and its network model are stored in 5 second snapshots for planning activities. This data is stored in commercial power flow and dynamics data files. At the time of disturbance events, data is stored in much smaller time stamps to be used for model validation, disturbance analysis and other planning related studies.

Within this methodology, either existing static or dynamic state estimators are used as the starting blocks of path transfer determinations.

4.2.1.2 Manually Selected Input Data

The inputs into the operational path transfer methodology include the following-

- List of contingencies – These include a set of Pre- defined contingencies identified based on operator experience or planning recommendations to be considered during path transfer calculations

- List of monitored elements – These include the set of power system components (paths, interfaces) that need to be continuously monitored to ensure there are no violations or instability concerns.
- RAS Schemes – RAS schemes identified from planning studies or past operational experience are included into the methodology.
- Generator Dispatch and Load forecast data – Generator Dispatch and Load Forecast data are included into the methodology to make calculations of forward operational horizons including hour ahead, and week ahead.
- Topology changes – Expected changes in system conditions including scheduled outages for maintenance etc., are used as inputs into the methodology for network model updates for period of path transfer calculation.

4.2.1.3 Path Transfer Flow Calculation

Path transfer flow calculations are made using this component of the methodology. Given a specific source and sink area, the curve is traced till the point of maximum power transfer. The first transfer size is incremented in a user defined step size and then moved to a more adaptive step sizing in order to reduce computation time.

The key steps involved in this process are described below –

1. Initialize all power system data.
2. Define a starting transfer size in the direction of loading/generation variation and schedule transfer.
3. Adaptively predict next transfer size based on previous transfer solution.
4. If any violation recorded, scale transfer size in reverse direction and repeat prediction/correction.
5. Step size increments are made based on monitoring of distance to instability or system divergence point.

Figure 10 below highlights the differences between fixed step size and adaptive step sizes.

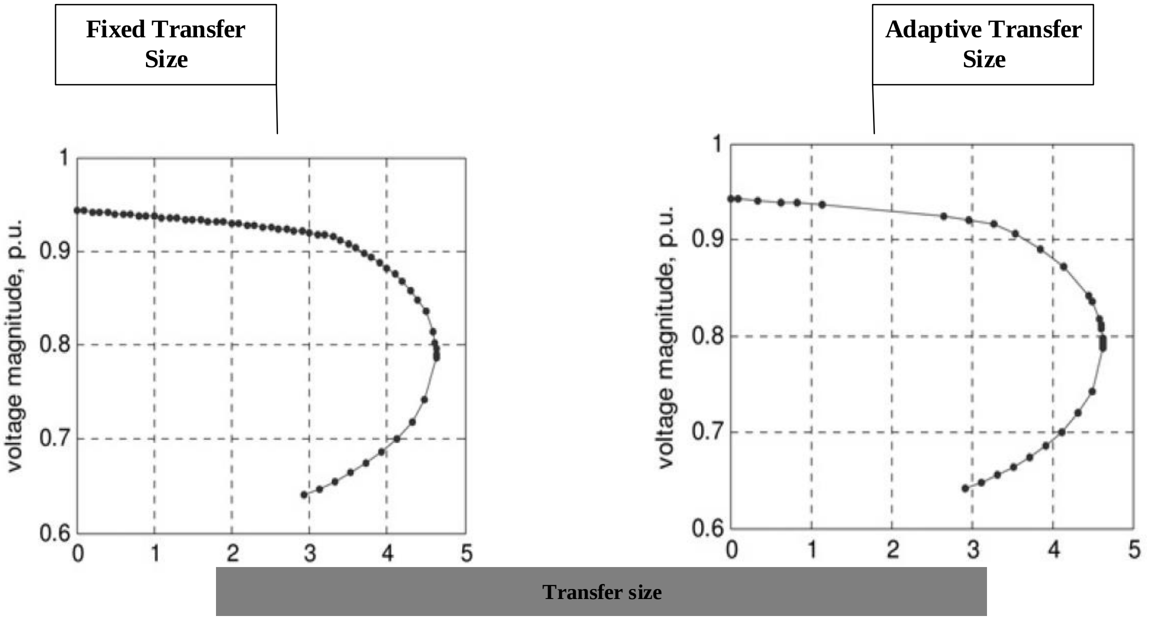


Figure 10: Fixed Step Sizing vs. Adaptive Step Sizing

As observable from the plots above, adaptive transfer sizing takes fewer iterations to reach the final solution unlike fixed transfer size solution.

4.2.1.4 Online Contingency Assessment

Within this component of the proposed methodology, contingency screening and assessments are performed in the real time operational environment for every transfer step size. Contingencies are both manually selected and used as inputs into the algorithm, or they can be automatically screened and ranked for assessment.

Automatic contingency screening algorithms can be used to rank contingencies based on steady state and dynamic stability. They are performed by optimizing the network in real time or near real time environments to identity post contingency voltage deviations, post contingency thermal overloads and dynamic instability scenarios. They make use of heuristic or deterministic algorithms for faster processing and analysis. Only those contingencies identified as most critical with involve further detailed time domain simulations.

The results from screening and post contingency evaluations are made available to operators in real time.

4.2.1.5 Dynamic Security Assessment

In the operational real time horizon, commercially available software tools allow for determination of power grid margins to instability. This component works in close coordination with the OCA tool wherein stability limits of the system are computed at every loading step for considered contingencies.

The voltage stability criteria are monitored consistently within the process and any violations are reported. Transient and dynamic stability simulations are performed in a computationally intensive time domain manner "only" if they are identified critical from the past operator experience or previously discussed contingency screening algorithms. The stability results are translated to the required operating parameters, to create an operating region within which the system is stable.

The total path transfer capability is identified as the minimum of voltage, thermal and dynamic stability limited path transfer along the considered loading/ and generation pattern.

4.2.1.6 Look Ahead Calculators

Look ahead calculators use load forecast data, generation dispatch schedules, state of the system, proposed power transfer agreements and anticipated changes in system operating conditions to calculate total path transfer for periods ahead of time including hour ahead and day ahead.

Based on the real time state estimation solutions at hour 0, base cases for the next period under consideration are generated using the above information (1 – 168 hours – 7 days ahead), before beginning the calculation process.

4.2.1.7 Load Forecast Error Calibration

The load forecast errors are reduced as a minimization function responding to the differences in forecasted loads and real time load data collected. This would help improve the accuracy of look ahead total path transfer calculations.

4.2.1.8 Volt/VAr Optimization

Volt/VAr optimization feature of the methodology can be used to increase the loadability or total path transfer across the interface by controlling the various network devices for example FACTS devices and generator reactive power outputs. They can be implemented only in a

WAMPAC enabled environment. They provide operators with additional control opportunities to improve network reliability and path transfer capability.

Figure 11 discusses the process flow, analytical stages involved and detailed methodology in the form of a flow chart. The flow chart highlights the flow of information between various components of the methodology discussed in earlier sections of the report.

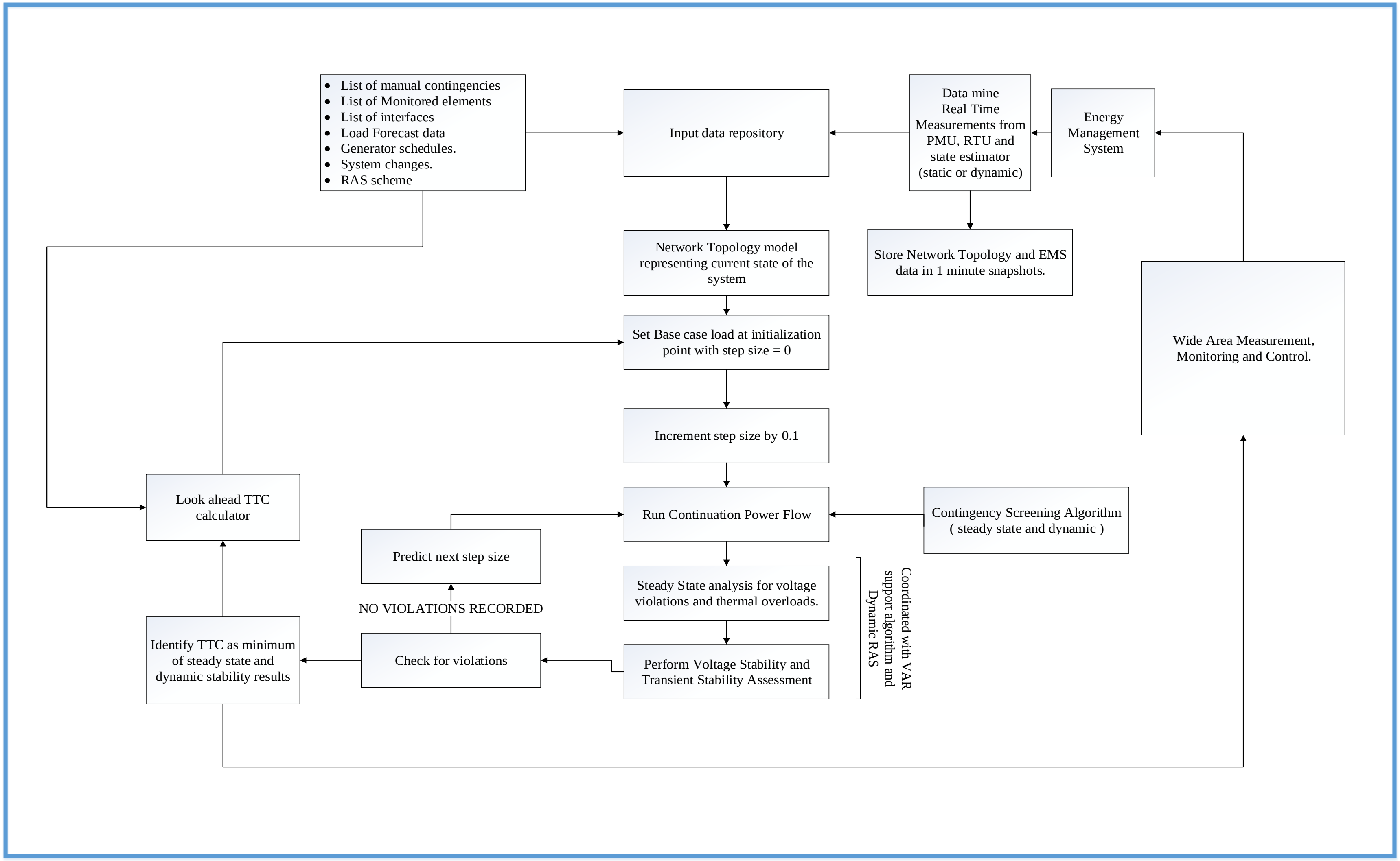


Figure 11: Detailed Flowchart of Operational Horizon

A summary of the stages involved in the flow chart above is presented below.

1. Real time measurements from Phasor Measurement units and Remote Terminal Units, combined with dynamic/static state estimation provide for a wide area representation of the state of the system and network topology i.e. the base case.
2. A list of credible contingencies are generated using the contingency screening algorithm or manual selection of contingencies.
3. The list of monitored elements is provided.
4. The load forecast data and generation schedules is also provided as an input.
5. The path transfer tool is started at the current system loading level.
6. At every transfer step size increment, using the current state of the system, a steady state evaluation is performed to define static bounds on the path transfer.
7. Similarly a voltage stability and transient stability assessment is performed at every loading step to define dynamic bounds on the path transfer.
8. At every transfer step size, the available control from Volt/VAr optimization of existing network control devices will be assessed to further enhance the path transfer and improve reliability.
9. All applicable RAS schemes are included in a table. At every transfer step, Dynamic RAS can validate performance of existing RAS schemes and identify better RAS schemes within the confinement of existing RAS design and equipment that could improve path transfer under critical conditions.
10. The Total Path Transfer is identified as the minimum of the steady state and dynamic bounds on power transfer.
11. The operating parameters of interest are mapped to the stability results to develop nomograms representing safe regions of system operation.
12. Specific Safe Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) obtained from planning cases will be monitored using real time states of the system. SOLs will be continuously monitored parameters at Transmission operator facilities in real time.
13. Using the load forecast data, and expected changes to system topology, the look ahead algorithm calculates the total transfer capability for durations into the operational future.
14. During the real time horizon, the total path transfer will be calculated in 15 minute intervals.
15. A representation of the current states and network configuration from EMS for 5 second snapshots is saved as a power flow and dynamics data file into a repository.
16. A feedback loop is included where the error in measurements of load forecast data is fine-tuned against real time load data received.
17. Input data files can manually change schedules as per requirements of EIM dispatch, or reserve sharing agreements.
18. During the operations stage, there will be three sets of path transfers that are visible at control center. One from the planning stage (fixed), one that is updated every fifteen minutes, and the other is the current operating state of the system that is obtained from real time measurements of MW flows along the line at PMU/SCADA data rate. This three

dimensional frame will provide an operator with better decision making capability to support control actions.

4.2.2 Planning Horizon Data and Tool Requirements

4.2.2.1 Power Flow Cases

Power Flow cases are built typically built from forecasted data and generation schedules obtained from production cost modeling software. Different study scenarios are built into these base cases reflecting the period of study interest. Within the FASTC methodology, the accuracy of these models are further improved by replacing traditional bus – branch representations by node- breaker representation of the network. Plans are already underway to transition WECC models to breaker-node representation.

Node breaker representation of the system will bring these power flow cases a step closer to real time EMS environment models. The differences between the two are highlighted in figures 12, 13 and 14. Figure 12 shows the EMS network model while Figure 13 and 14 show the corresponding bus- branch and node breaker models respectively representing the same network model.

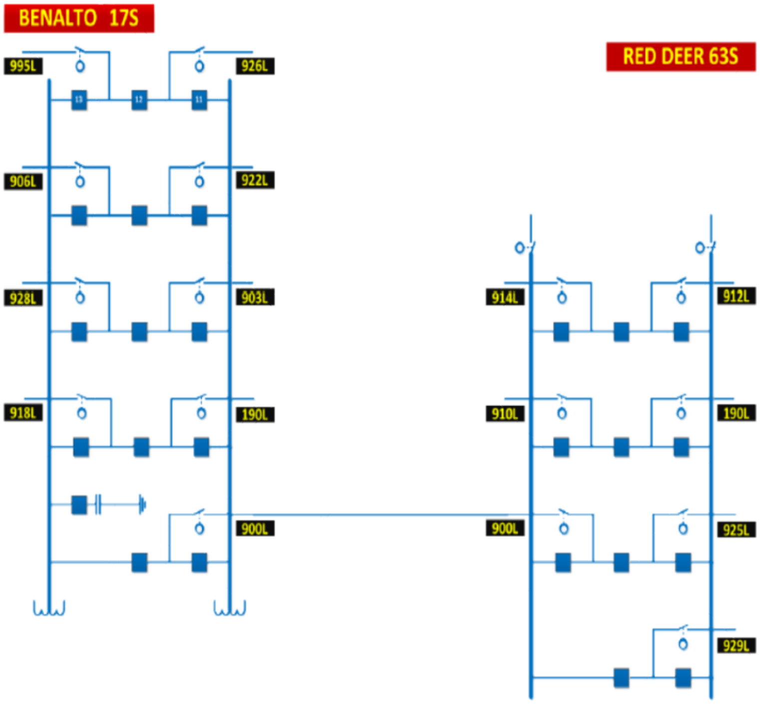


Figure 12: EMS network model

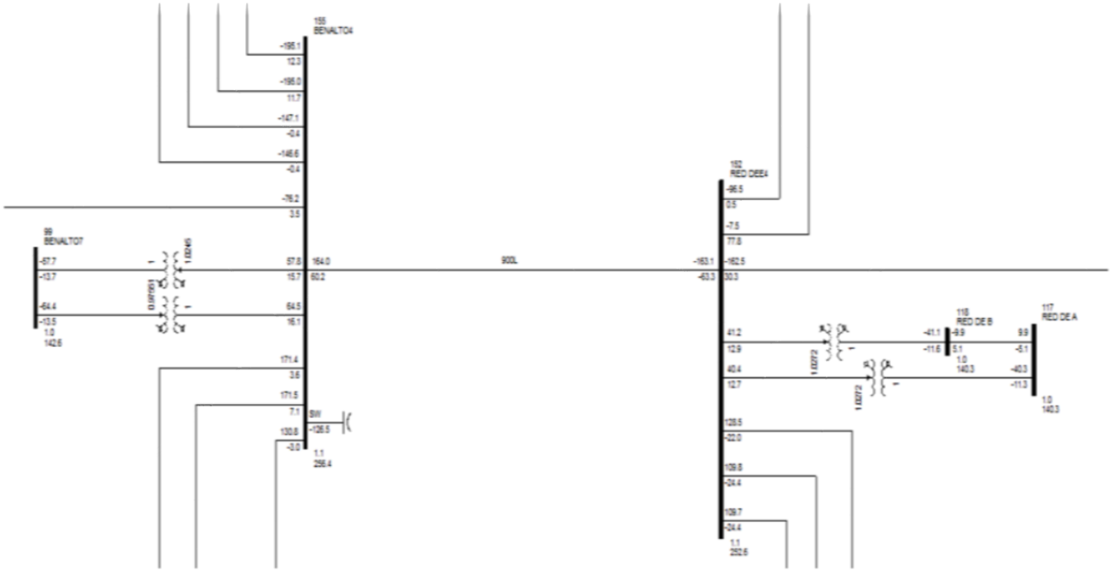


Figure 13 : Bus- Branch network representation

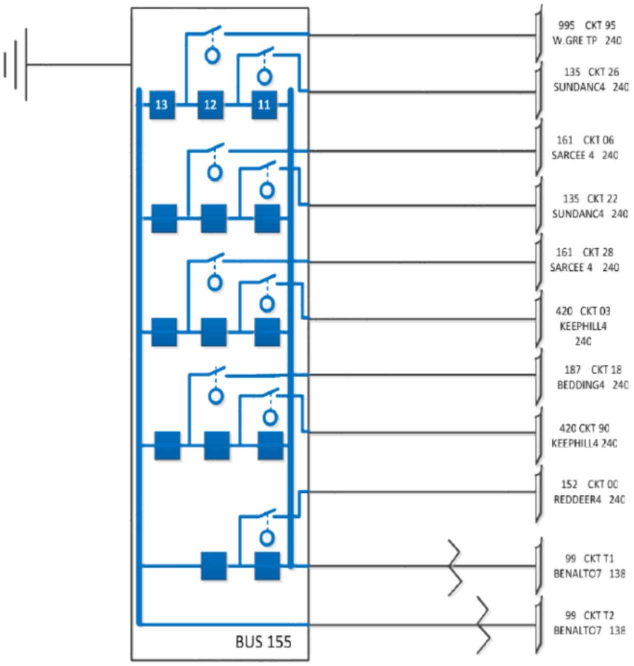


Figure 14 : Breaker node network representation

The improved accuracy in using node- breaker models are clearly visible by comparing the above figures. The node- breaker models allow for increased accuracy in modeling of special protection schemes or RAS schemes, while improving visibility of substation configurations and equipment. The node breaker models can also easily be validated against EMS network models. Most commercial tools model node – breaker system representations.

4.2.2.2 Error Calibration and Model Validation

The error calibration and model validation component of this methodology further improves the accuracy and quality of planning models by validating power system dynamic models and their associated parameters against past disturbance events and historically available PMU data, Digital Fault Recorder data and EMS snapshots. Improved quality of planning based models, allows for enhanced accuracy in forward planning path transfer calculations.

Most commercial error calibration and model validation techniques used today are time consuming processes, wherein playback features are used to individually tune single parameters of the dynamic models within their operating range. In the proposed methodology, the entire process can be batch tuned based on parameter sensitivity analysis. Wide Area

Measurement systems (WAMS) and large scale PMU data availability in the range of milliseconds, allow for enhanced tuning of the model dynamic parameters. Figure 15 provides an overview of the entire process.

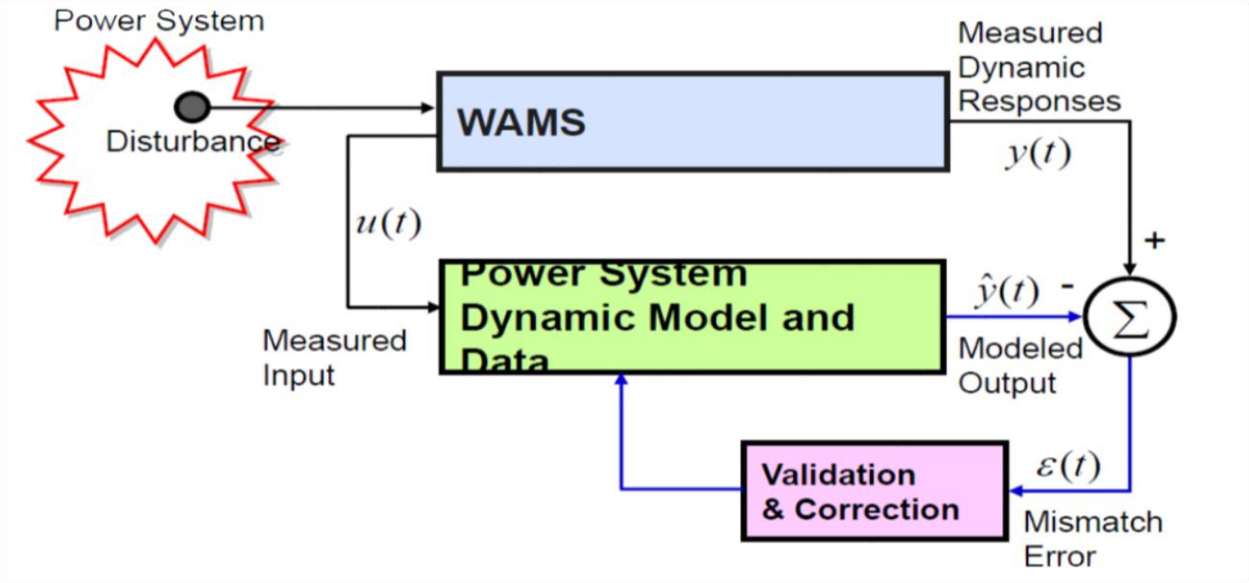


Figure 15 : Model Validation Process

4.2.2.3 Manual Inputs

The manual inputs used in the planning horizon of FASTC methodology are quite similar to those used in the operational horizon –

1. List of contingencies – This includes a list of manually selected contingencies to be studied based on operator experience or past planning recommendations.
2. List of monitored elements – This includes a list of elements, interfaces or network components that needs to be continuously monitored to ensure system reliability.
3. Generation Schedules and Load Forecasts – Generation Schedules and Load Forecast data are used to build the planning base cases.

4. List of scenarios – The list of scenarios represent modifications to be made to planning base cases to represent anticipated operating conditions in the forward planning horizon.
5. RAS schemes – All applicable RAS schemes are modeled into the base cases.

4.2.2.4 Path Transfer Flow Calculation Tool

In the FASTC methodology, the same path transfer flow tool described in the operational horizon can be used in the planning horizon. This tool will increment the transfer size between Area A and Area B based on a first iteration of user defined step size. Beyond the first iteration, the algorithm adaptively adjusts its transfer size based on previous transfer solution and monitoring distance to solution divergence.

4.2.2.5 Contingency Screening and Analysis

In the proposed methodology, the same contingency screening algorithm discussed in operational horizon can be used to screen and rank critical contingencies based on post contingency anticipated voltage deviations, thermal violations and dynamic instability. Critical cases identified can be moved to more detailed time domain analysis. Manual contingency selection can also considered during the analysis.

4.2.2.6 Voltage and Transient Stability Assessment

Similar to DSA functionality discussed in operational horizon, voltage and transient stability assessments are performed at every transfer step size for considered/identified contingencies in the network. This component of the methodology can be automated to batch process a large number of runs in parallel thereby reducing study time during planning horizons as well.

The path transfer capability is identified as the most limiting of computed voltage, thermal and transient stability path transfer limit.

4.2.2.7 RAS Schemes

RAS schemes are modeled into the base cases as manual inputs based on operator experience and planning studies. Dynamic RAS schemes similar to those discussed in the operational horizon can also be considered within the proposed methodology for planning horizons. Dynamic RAS algorithms optimize through designed RAS schemes and the network model to identify potential mitigation strategies that could provide better reliability and enhanced path transfer.

Considering the close relation between path transfer calculations and armed/ modeled RAS schemes, the accuracy of path transfer calculations can be significantly improved. This includes the combined benefits of RAS modeling in node-breaker models with improved substation visibility.

4.2.2.8 Load Forecast Data

The interface between Transmission and Distribution network is currently modeled using load modifiers that represent aggregated loads in particular utility operating areas. Their accuracy can be further improved by taking advantage of commercial technologies like smart meters. Smart meters can be used to record fast and accurate demand and consumption data. This data can be further aggregated based on customer class behavior, climatic zones etc. and then forecast with improved accuracy. This forecasted data can be modeled more discretely at different substation bus in the power system models. They make use of local load forecasting software tools to create a forecast model that takes into consideration all system parameters such as weather, temperature and temporal conditions.

Another aspect would be to improve the representation of distributed generation at the T-D interface in planning models, which could have a significant impact considering future scenarios with higher penetrations of renewables in the network.

4.2.2.9 Volt/VAr Optimization

In the planning horizon of the FASTC methodology, the Volt/VAr optimization algorithm can be used to increase path transfer between two areas of the system. This tool is also used interoperable between the planning and operational horizons.

With adequate models representing the VAr devices in the planning base cases, heuristic and deterministic optimization algorithms can be used to meet the pre- specified goals of both improved transfer and network reliability.

Figure 16 describes the process flow, analytical stages involved and detailed methodology in the form of a flow chart. The flow chart highlights the flow of information between various components of the methodology discussed in earlier sections of the report.

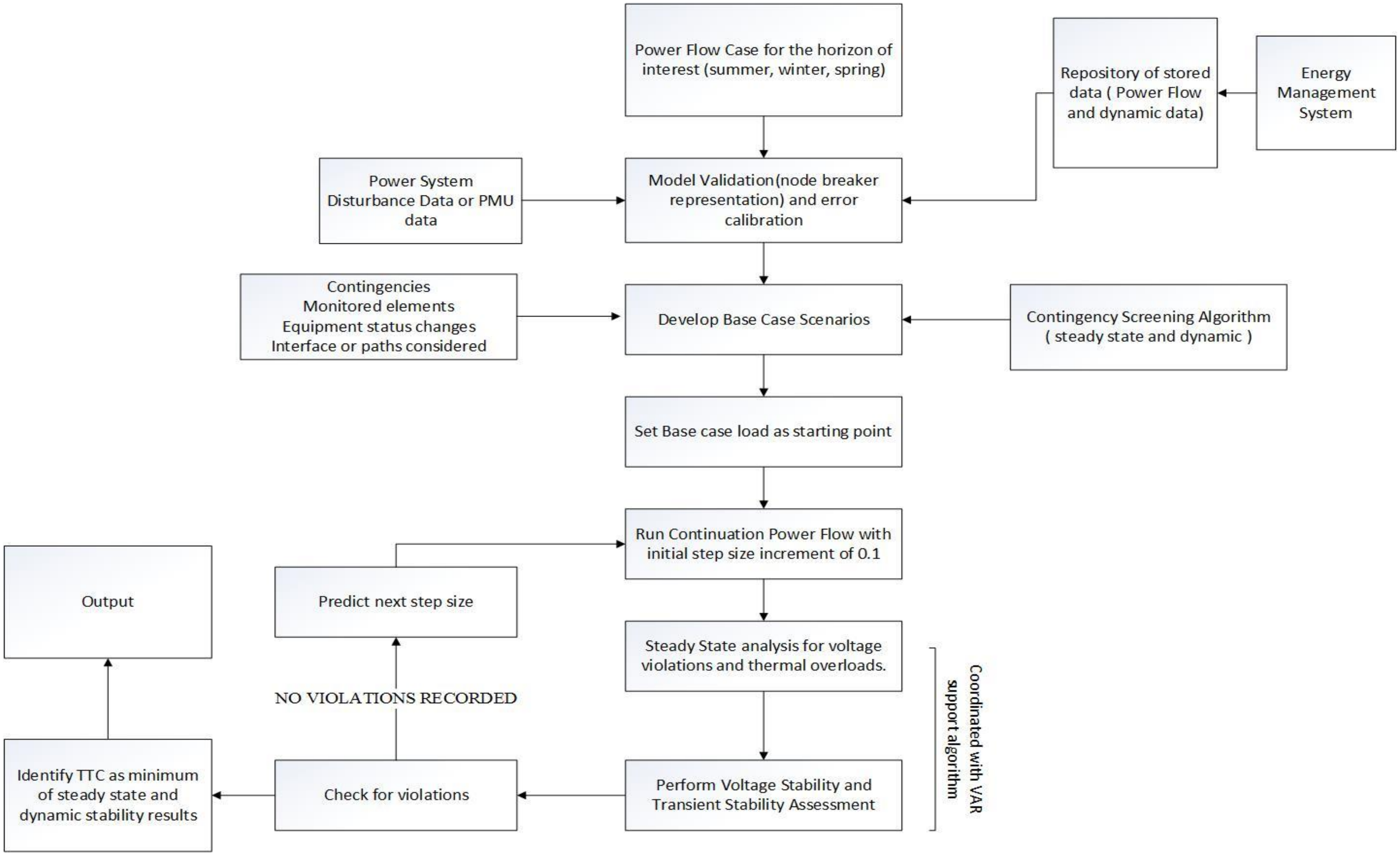


Figure 16 : Detailed Flowchart of planning horizon.

A brief summary of stages involved in the flow chart above are presented.

1. During the planning stage, EMS models with detailed node breaker representation will be calibrated against node breaker system representation in planning base cases. This is performed by automated scripts that validate the status of existing branches and substation equipment between EMS models and planning models
2. The existing database of historical PMU and SCADA measurements provide information for calibration of network dynamic models. The output of this stage will be a more accurate representation of the components in the network in the form of input steady state and dynamic data files.
3. The base case is developed using load forecast data and generation schedules to represent the period of interest
4. The set of monitored interfaces/lines in the network can be specified in this model.
5. The path transfer calculator will be used to increase the transfer step size between considered areas based on user defined or adaptive step sizing.
6. While identifying potential scenarios to study the base case, two options can be considered for contingency assessment. One will include user specified contingencies and the other will include an automated contingency screening algorithm.
7. During each load transfer stage, the voltage stability and transient stability of the system will be evaluated to identify potential violations. This stage will repeat until the maximum load transfer point is reliably reached. During this stage, set of Safe Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) will be identified.
8. The Remedial Action schemes or Special Protection schemes will also be modeled into the case/ identified. Dynamic RAS can be used to identity existence of alternate designed RAS that could further improve path transfer.
9. In coordination with every load step increase, heuristic VAr devices optimization can look to further increase the path transfer at each stage by optimizing the VAr control devices in the network.
10. Reports are then generated based on the requirements of the user.

The path transfer limits obtained from planning horizon can be used in the operations horizon as well to serve as a precursor to near real time operations. However, the total transfer capability will be updated in operations horizon as well.

4.3 Technical Discussion of Key Components

In this section of the report, a technical discussion is provided to highlight the key features and components of the FASTC methodology. Most of the discussed algorithms can be found in literature, and appropriate references to the figures and technical details are provided in the appendix - B. The highlight of this methodology is that it takes advantage of a combination of commercially available tools, and organizes the process flow of information between them, as discussed in earlier sections of the report.

4.3.1 State Estimation

Measurements are made available through traditional SCADA or Synchrophasors (PMU) deployed around the network. Traditional state estimators use only SCADA measurements, however, current strategies see a mixed deployment of both SCADA/RTU and PMU measurements being used which is referred to as hybrid state estimation. Dynamic state estimators using only PMU data is considered in the methodology as well keeping in mind a five year deployment strategy.

The FASTC methodology can be easily adopted to work with static or dynamic state estimators.

4.3.1.1 Static State Estimators:

Static State estimators (SSE) use a network reduced model representing only key internal areas of the system. The generators and loads in the external system are generally lumped while modeled. They can also use a wide area network model which improves visibility to surrounding areas.

State Estimators are typically used to estimate the state of the system at a particular time snapshot “t”. The methodology is slightly different for each kind of measurement technology under consideration.

When only SCADA measurements are used the system is represented by a nonlinear model.

$$Z = h(X) + \gamma \qquad (1)$$

$$H_x = \nabla h(X) \qquad (2)$$

Where X represents the state vectors in the system. X = $[\theta_2, \theta_3, \ldots \ldots, \theta_N, |V_1|, |V_2|, \ldots \ldots, |V_N|]$

Z represents the set of measurements, typically active and reactive power flows in network elements, bus injections and voltage magnitudes at the buses.

H represents a set of nonlinear functions of the state vector.

γ represents the noise error vector.

Similarly in the case of Phasor measurements alone, the network is represented by a linear model.

$$Z = H.X + \gamma \tag{3}$$

H = Function of network parameters only (completely linear).

Hybrid State Estimation

Considering a deployment environment where both PMU and SCADA technology will provide measurements, the following stages are involved in the process.

1. The measurements are received from PMU units through Phasor Data Concentrators, and Remote terminal units (RTU) after data acquisition.
2. In traditional state estimators, the state vector from (1) is estimated using weighted least squares. In formulation,

   $$\dot{x} = \arg\min[z - h(x)]^T W^{-1} [[z - h(x)] \tag{4}$$

   Where W is the weighing matrix, and the solution for $\dot{x}$ is obtained in an iterative fashion by linearizing around available estimate at current iteration.

3. The iterative process is terminated when the norm of the residual falls below a predefined value.
4. In hybrid estimators, PMU measurements can be mixed with traditional power flow measurements or by use of a two stage scheme, where the state estimate obtained from SCADA measurements are improved by second estimator that employs PMUs.
5. In the former method, the PMU state v of complex phasor (Cartesian coordinates) are related to the conventional state vector x in polar coordinates, through a simple transformation $v = g(x)$. This can be represented by

   $$\begin{bmatrix} z_1 \\ z_2 \end{bmatrix} = \begin{bmatrix} h(x) \\ Ag(x) \end{bmatrix} + \begin{bmatrix} n_1 \\ n_2 \end{bmatrix} \tag{5}$$

   Where z_1 and n_1 are the conventional measurements and noise vectors, and z_2 and n_2 are the PMU measurements and transformed noise vectors.

6. In the latter method, the two step approach starts off with converting the conventional state estimate x into voltage Phasor by $v = g(x)$, and then using it in an augmented form of the linear measurement model.

$$\begin{bmatrix} v_1 \\ z_2 \end{bmatrix} = \begin{bmatrix} B \\ Y \end{bmatrix} \mathrm{v} + \begin{bmatrix} u_1 \\ u_2 \end{bmatrix} \qquad (6)$$

Where B selects the relevant phasor, and u_1 and u_2 are the noise vectors.

7. We now solve for the unknown phasor v using the Weighted Least Squares approach. Another approach would be to use Least Average Values (LAV) while solving for the unknown phasor. This uses linear programming (single solution) which improves robustness of estimates and eliminates need for bad – data analysis.
8. Additional stages include bad data detection and network topology processor which are common to current practices.

PMU only State Estimation

1. In the PMU only state estimator, the following information is available to the EMS system –
   a. Voltage phasors at all buses.
   b. Angle phase difference.
   c. Current phasor on a line between two buses.
2. All the above measurements can be aggregated into a vector z. This vector is linearly related to the voltage phasors. Hence, the PMU measurements satisfy,

$$z = Av + u_1 = \begin{bmatrix} B \\ Y \end{bmatrix} \mathrm{v} + u_1 \qquad (7)$$

   Where, each row of B is a unit vector associated with a voltage phasor available.

   Y is the admittance matrix corresponding to the current phasor

   u_1 is the measurement noise.

3. The above formulation makes the process non iterative and the solution highly linear. The direct solution of system state $\dot{x}$ is obtained by

$$\dot{x} = G^{-1}H^{T}R^{-1}Z \qquad (8)$$

   Where G =$H^{T}R^{-1}H$

R= noise error covariance.

4.3.1.2 Dynamic State Estimators

Dynamic State Estimators (DSE) are capable of tracking the current system states and also predicting the state vector at the next sampling time. Prediction capabilities ensure system visibility even in the presence of observed system islands. Dynamic state estimators use improved network topology models in their EMS system. These models include the generator and load dynamics as well in detail. These are essential to capture the inherent dynamics of the system. The Kalman filter is the best tool for dynamic state estimation.

This is mathematically represented as

$$\dot{x} = f(\dot{x}, u, 0) + L(y - \dot{y})$$

$$\dot{z} = h(\dot{x}, u, 0)$$

Where, x is the state vector, u is the input variables, and z is the measured variable. L is the observed gain and $\dot{x}$ and $\dot{z}$ are the estimated state vectors and estimated measured vector, respectively.

The final outputs from the state estimator stage include the voltages, phase angles and flows on all the lines in the network topology model. Also the status of various devices including circuit breakers, generators etc. are available.

Figure 17 compares the time frames and state estimator outputs of static and dynamic state estimations. While static state estimators can capture system states at time intervals of t+dt, dynamic state estimation can capture more discrete time frames in between t and t + dt, example t'.

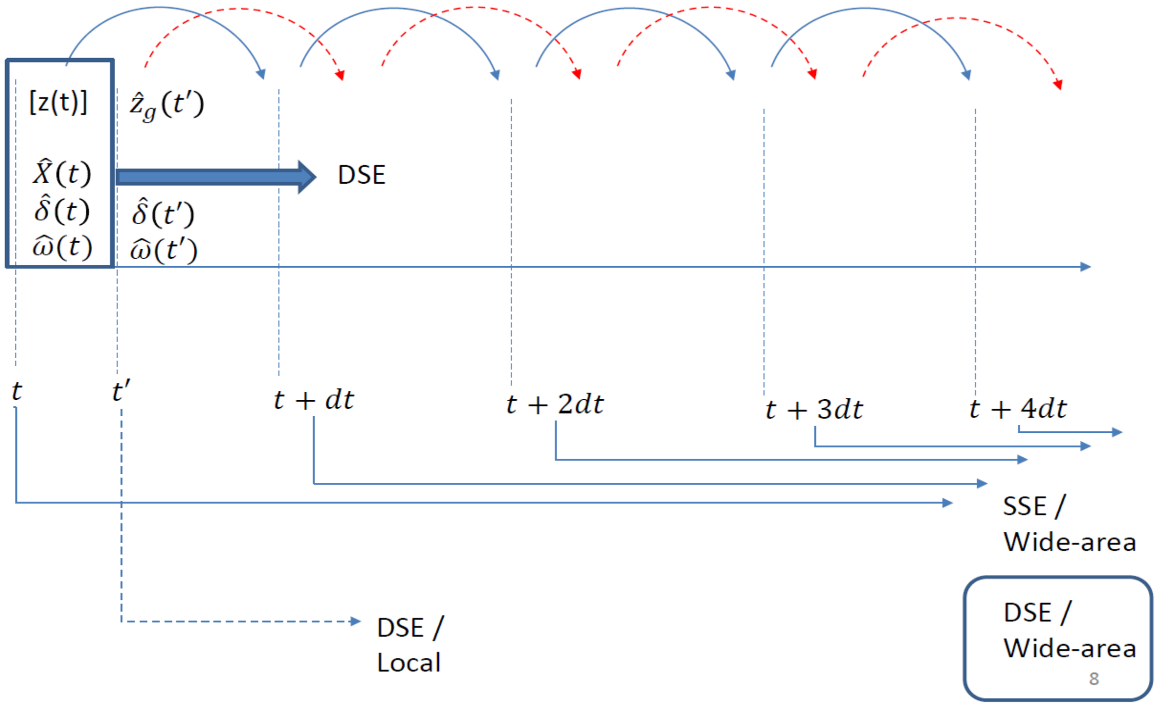


Figure 17 : Dynamic State Estimation vs Static State Estimation

4.3.1.3 Test System Analysis

A reduced network model of the WECC interconnect (WECC – 179 bus system) was analyzed to test performance of different state estimators. The objective of this analysis was to identify the number of PMU units that would be needed to provide complete visibility to the network.

These tests were conducted using serial computing power of single processing units, hence the solution time cannot be reflective of actual performance in a control center environment. The results indicate that a total installation of 53 PMU units would be sufficient to provide complete visibility to the Western Interconnection in a dynamic state estimation environment. This would include estimation of states of all generators and control devices in the network. Similarly in a static environment, 45 PMU units would provide complete visibility to the 179 bus system.

Figure 18 provides a representation of the WECC 179 bus network, and Figure 19 provides result from the comparison of state estimator performance.

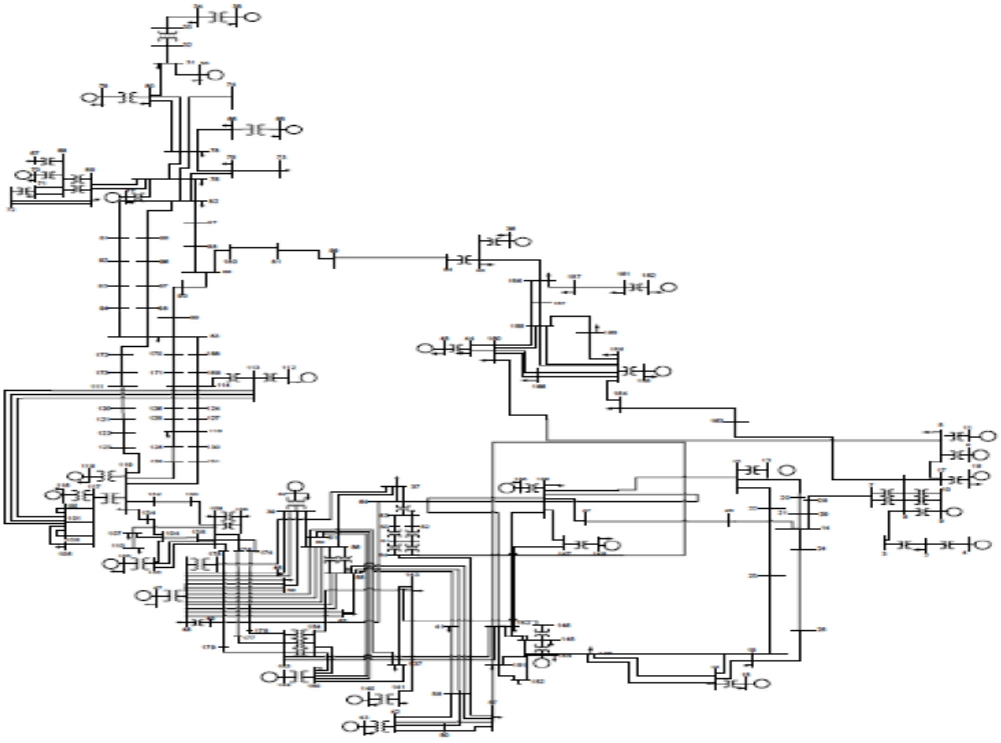


Figure 18 : WECC 179 bus network

	Static State Estimator		Dynamic State Estimator
	Hybrid State Estimators	PMU only state Estimators	PMU only state Estimators
Data synchronization time stamp	3-5 minutes	seconds	seconds
Outputs	Voltage, Phase angles	Voltage, Phase angles	Voltage, phase angles, generator rotor angle, rotor speed, controller states
Problem type	Non-Linear	Linear	Linear
Solution time	~2-5 minutes	~1 minute	~1 minute

Figure 19 : Comparison of performance of state estimators

4.3.2 Continuation Power Flow/Repeated Power Flow

Given a specific source and sink area, the continuation/repeated power flow can be used to trace the curve till the point of unconstrained maximum load and maximum transfer capability. This process is repeated for step size increments in the direction of loading/ generation variation. Most commercial tools use this method for TTC calculations.

The net active and reactive power injections at the sink and source buses are augmented as functions of λ.

$$P_i = P_{i0} + \lambda L_{Pi} \tag{8}$$

$$Q_i = Q_{i0} + \lambda L_{Qi} \tag{9}$$

λ : Parameter controlling the amount of injection.
P_i = base case real power injections at the bus
L_{Pi} = real power load participation factors.
Q_i = base case reactive power injections at the bus
L_{Qi} = reactive power load participation factors.
V = Voltage at bus
θ = phase angle at bus

The solution for system states at any new perturbation point is given by

$$\begin{bmatrix} \theta^i \\ V^i \\ \lambda^i \end{bmatrix} = \begin{bmatrix} \theta^i \\ V^i \\ \lambda^i \end{bmatrix} + \Delta \begin{bmatrix} d\theta \\ dV \\ d\lambda \end{bmatrix} \tag{10}$$

The solution is then corrected while accounting for the continuation parameter by using:

$$\begin{bmatrix} f(\theta, V, \lambda)^T \\ \Delta_k - x_k \end{bmatrix} = 0 \tag{11}$$

The steps involved include:

1. Input power system data
2. Initialize by verification of no base case violations and set tolerance for change of transfer power.
3. Initialize the transfer with user defined step size
4. Predict the step size of CPF :

   a. Calculate the tangent vector.
   b. The next scalar prediction step size λ is based on solution convergence monitoring from previous step size. Based on number of iterations taken for power flow to converge, the transfer size can be adaptive.
   c. Make the step size increment to predict the next solution.
   d. Correct the solution with continuation parameter.
5. If there are violations recorded at step 3c, reduce the step size by 0.05λ. then go back to 3c.
6. At every stage voltages at all the buses and thermal loading of all lines in the network are verified.

Step length control is a key element that affects the computational efficiency of the continuation method. It affects the method in the following two ways-

1. Speed – convergence to specified accuracy.
2. Robustness- convergence to true solution.

4.3.3 Load Forecast Data

This data is currently provided by load balancing authorities and reliability coordinators. They are generated by a combination of load forecasting software tools. These tools use a forecast model to provide system load forecasts considering different system parameters such as weather conditions, temperature, and temporal conditions (season, day, and hour). The load forecast data is used by state estimators to determine the state of the system at any point of time, and also for online look ahead TTC calculations. They are also used in the planning models where aggregated forecasts are used to build future base cases of interest.

Unlike traditional aggregated system level load forecasting, with the availability of real time smart metering data, the accuracy of load forecasts can be improved by improving the models used. The principal is to group smart meter load data based on consumption behavior similarities to forecast high level system load conditions. This involves the following stages –

- ✓ Exploring data sets and meaningfully summarize them into smaller groups of load profiles.
- ✓ A k means clustering algorithm is used for this purpose. K means clustering is a data mining algorithm used to partition a data set into a smaller number of clusters by minimizing the distance between each data point and the center of the cluster.

- ✓ These clusters are further simplified based on customer behavior load pattern grouping to determine a suitable number of clusters.
- ✓ After each smart meter has been assigned to a cluster, the smart meter interval data is grouped to obtain the partial system load forecast. The partial system could refer to a substation bus, different zonal climates etc.
- ✓ The partial system load forecast is summed to obtain aggregated load forecasts as needed.
- ✓ Traditional Neural Networks based load forecasting model is used with the Lavenberg – Marquardt approach to train the model.

A flowchart describing the algorithm is discussed in Figure 20.

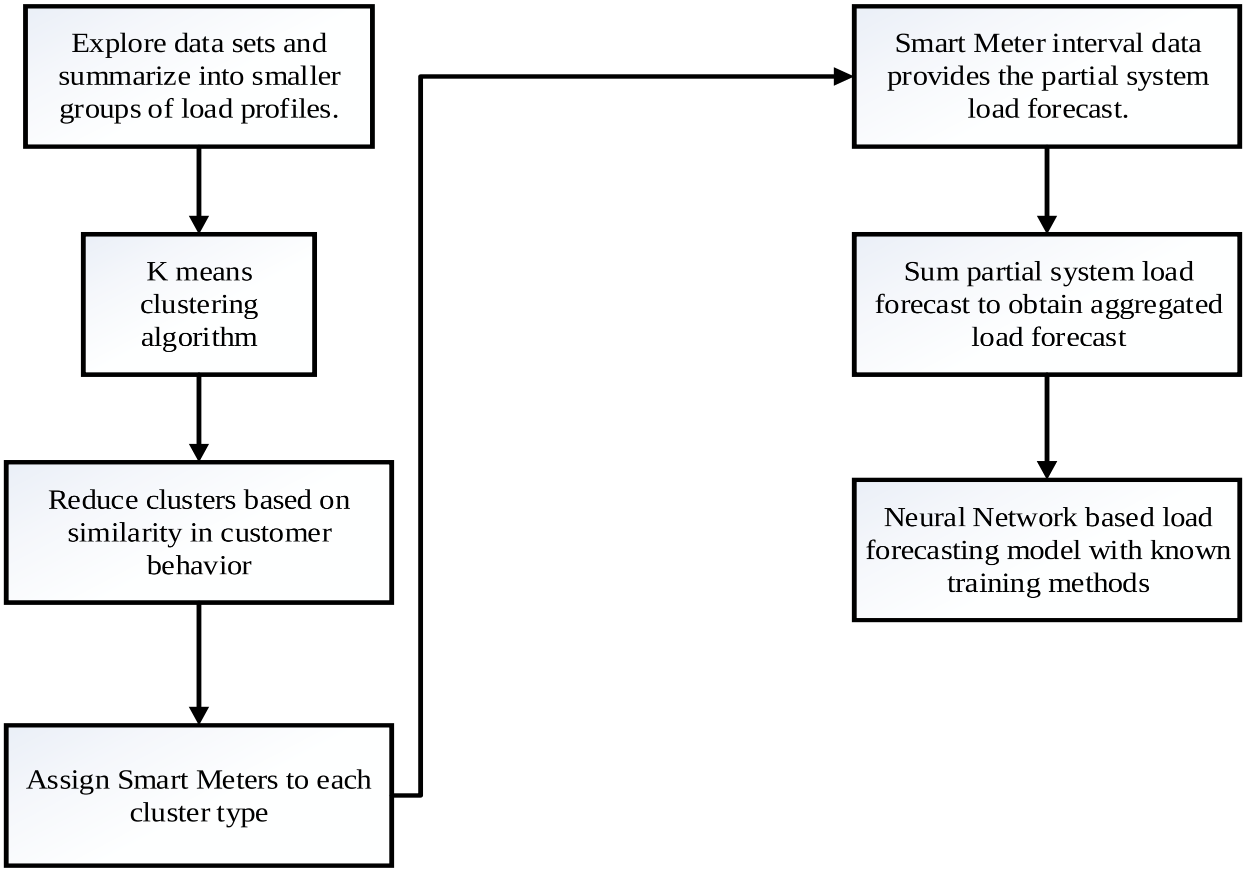


Figure 20 : Load forecasting algorithm Flowchart

4.3.4 Critical Contingencies

Critical contingencies can be identified in the following two ways –

4.3.4.1 Manual Contingency Selection

Critical contingencies identified either during planning stages or based on utility or operator recommendations can be selected and input to the TTC calculator.

4.3.4.2 Automatic Contingency Screening and Assessment

A fast contingency screening algorithm can be used that will use the current state of the system, and rank the most critical contingencies in the network. Contingency screening can be considered for both voltage stability and transient stability cases.

In the case of voltage stability screening, a post contingency voltage deviation margin can be used. This margin can be set for example to 5%, and all post contingency cases reporting deviations larger than this margin, will be ranked from higher to lower.

In the case of dynamic contingency screening, the computation is done in two stages. Firstly, the fault locations are identified for the most severe faults. These are the weakest points in the network. Next the most severe faults are ranked. The ranking index is based on the properties of the energy function method.

The most critical fault locations are identified based on the difference between real power flow at the bus and generator real power in the vicinity of this bus. They are also identified based on real power leaving a bus. The characteristics that have an impact on the dynamic stability of the power system are generator kinetic energy, electrical torque, voltage and shape of potential energy represented by the Eigen value. The ranking index is formulated as a combination of all the above characteristics based on the critical clearing time computed for each fault. Additional details can be found in the references.

$$RI = k_1 * KE + k_2 * \max\left\{\left(0; \left(1 - \frac{M_{ePOSTF}}{M_{ePREF}}\right)\right)\right\} + k_3 * \min\left\{\left(0; \left(1 - \frac{M_{ePOSTF}}{M_{ePREF}}\right)\right)\right\} + k_4 * (V_{PREF} - V_{GEN}) + k_5 * \left(\frac{EigenValue_{POSTF}}{EigenValue_{PREF}} - 1\right) \tag{12}$$

4.3.5 Remedial Action Schemes

The remedial action schemes can be triggered/armed online or offline by the operator. They are stored in a look up table, and the data can be modified or added as required. Future advances will allow for dynamic RAS schemes to be available online. In this scenario, for the most critical contingencies in the system, separate processors will run through a predefined set of actions for ex: load shedding, generation redispatch, generator trip, line switching etc. and identify potential solutions that could improve the transfer capability within bounds or mitigate violations of the current operating state.

4.3.6 Voltage Stability and Transient Stability Assessment

Most commercial tools are capable of handling real time voltage stability and transient stability calculations. Commercial tools such as Power Tech, V & R energy and Power World have been integrated with EMS systems to perform such studies.

After the most critical contingencies have been identified, voltage stability is analyzed in the form of PV and QV curves, along with power flow convergence monitoring. Power Flow convergence monitoring is used to verify if the power flow converges within defined number of iterations.

The critical contingencies identified from dynamic contingency screening are transferred to the time domain where they are evaluated using implicit or explicit integration methods.

At each loading step the time domain dynamic simulations will be run for critical contingencies identified.

4.3.7 Look Ahead TTC Calculator

The look ahead calculator computes the TTC for periods into the future using information of the proposed power transfer, look ahead loads, look ahead generation dispatch scheme and planned outage schedules. This model is refreshed using this data, and the procedure is repeated to calculate the TTC for hour ahead, day ahead and other time periods.

4.3.8 Data Repository

A configuration of the current system states and network topology is stored at 5 second snapshot intervals so that they can be used during the planning horizon for modeling error calibration and other offline studies. When there is a disturbance in the system, the data is stored in shorter cycle intervals.

4.3.9 Load Forecast Feedback Loop

The load forecast data error obtained as a difference between forecasted and real time load, is used to retrain the neurons in Artificial Neural Network (ANN) based load forecasting algorithms. This will assist in improving the quality of forecasted data.

4.3.10 Heuristic VAr device optimization

Heuristic VAr device optimization is used to maximize the loadability of the network subject to different network constraints. Based on the selection of available control devices (example – FACTS, capacitors, reactors), the maximum power transfer can be further enhanced by optimizing the status of their switching actions.

The most commonly used heuristic algorithms include genetic algorithm and particle swarm optimization.

4.3.11 Model Calibration

Model calibration, validation and correction is generally performed to improve the quality of power system dynamic models and associated data. They are generally performed for a set of critical components and parameters in the system. A flow chart for the process has been provided in earlier sections of the report.

In this process, the model bench marking is done against data collected during disturbance events, or PMU recorded data. The recorded data is played back into the dynamic models and calibrated using component tuning. The components are broken down into simplified groups determined from their sensitivities to greater mismatches. A single group of these parameters are tuned at once.

The most common parameters include generator dynamic parameters, load characteristics and reactive compensation devices.

4.3.12 Planning Models

The power system planning models will be replaced by node breaker representations. This is a step closer to the EMS models that exist in current control centers. With the shift from traditional bus branch representations to node breaker representations, they provide improved visibility to substation configurations and equipment.

Switching devices such as breakers, fuses, links and others can be modelled as breakers in planning tools, characterized by a status flag and flag type to differentiate manual or automatic switching. Nodes represent physical point of connection between power system components and switching devices.

5 COMPARISON OF EXISTING METHODOLOGY VS PROPOSED METHODOLOGY

In this section of the report, existing WECC path rating methodology is compared to proposed FASTC methodology. Different metrics were considered in order to make this evaluation. A simple demonstration of FASTC proposed methodology on a WECC rated path is included and its results are compared to current WECC path rating.

The following metrics are considered to compare the existing WECC methodology against the proposed methodology:

- ✓ Path Transfer calculation horizon.
- ✓ Operator tools and processes.
- ✓ Power system models.
- ✓ Real time data availability.
- ✓ Nature of path transfer calculations.
- ✓ Contingency considerations.
- ✓ Time and relevant factors.
- ✓ Control devices.

5.1 Path Transfer Calculation Horizons

Currently, the TTC is calculated during planning and operational horizons. The planning horizon based path transfer is obtained from reasonably adverse assumptions that cannot reflect all the dynamics of current or real time power system behavior. Based on anticipated changes in system operating conditions, the path transfer values will be recalculated during operational horizons for example, expected outages and scheduled equipment maintenance. The biggest disadvantage of this process is the inability of the calculated TTC to take into consideration real time or near real time operating conditions. The real time operating system conditions differ to a large extent from those assumed in planning models.

In the FASTC methodology, path transfer calculations will be made again in both the planning and operational horizons. However, the operation horizon now includes real time or near real time path transfer calculations. Due to limitations in current computing technology, path transfer limits calculated in real time will be updated within ten to fifteen minute time intervals. This will be coordinated with real time monitoring of power system operating conditions.

5.2 Operator Tools and Processes

In the current scenario, operators are capable of monitoring in real time the status of the power grid at a given instant of time. Online contingency assessment of pre-selected contingencies can also be performed to ensure system N-1 security. RAS schemes are stored within the control logic of the EMS. The process of path transfer determination and stability simulations still remain largely offline.

In the FASTC methodology, operators can take advantage of online tools that calculate the path transfer limits and dynamically update them in real time to near real time. This is performed in coordination with continuous monitoring of system conditions. Dynamic Security Assessments allow for near real time calculation of system stability and their imposed limitations. Adaptive RAS schemes can also work online to identify improved RAS schemes or better mitigation strategies under critical operating conditions, providing operator's information to improve or maintain path transfer limits during emergency conditions.

5.3 Power System Model and Base Case

Currently, planning based models are used for path transfer calculations. These models use traditional bus branch representation. Current EMS models however, use node breaker representation of the power grid. This results in a wide difference in planning models and operational models. The load forecast data used in current models are forecasted from the zonal/area level, not taking advantage of modern smart meter technology to further improve accuracy of load forecasts. Model validation is calibrated after major historical events, however the process is labor intensive and typically takes a long time due to insufficient data availability.

Within the FASTC methodology, planning models are replaced with breaker node representation of system components. This allows to bridge the gap between planning and operational models, allowing for improved accuracy in path transfer determinations. Load Forecast data is aggregated based on customer class level within planning area substation buses, thereby allowing for improved accuracy in planning model load data. With the larger availability of PMU data and dynamic state estimation, model validation is an automated process that batch tunes multiple parameters at once.

5.4 Real Time Data Availability

Current state estimators use SCADA measurements and static state estimators that have slower refresh rates and larger errors. There is also limited use of PMU measurements within the state estimation process. The rate of data transfer and availability at SCADA rate is insufficient to capture real system dynamic response.

The use of hybrid PMU and SCADA measurements in coordination with dynamic state estimators when available, enhance the speed of computations with minimized errors. PMU measurements have much faster refresh rates allowing for data to be recorded about 30 times during one second. This amount of data availability can capture network dynamics in the most effective manner. This would assist with enhancing and speeding the process of TTC calculations.

5.5 Nature of Path Transfer Calculations

As discussed earlier, the path transfer calculations currently made are typically not very accurate due to planning model assumptions made that reflect future operating conditions. For example, high summer cases used for TTC determination reflect a 1 in 10 year worst case loading scenario for local area studies, 1 in 5 for system wide studies, and similarly hydro cases are built from assumptions of future operating conditions. The trends are dictated by assuming less load diversity for smaller planning areas in comparison to larger loading areas.

In the FASTC methodology, the path transfer calculations are made using most up to date system information available in real time operations. The improved forecasting data increases accuracy of planning based TTC determinations along with improved accuracy of node breaker representations.

5.6 Contingency Considerations

Currently, pre-defined contingencies that are based on operator experience or planning recommendations are studied during operational and planning horizons. This might be a simplistic assumption going forward, where the nature of power grid operations are changing due to higher renewable penetration, energy imbalance markets, responses of storage and FACTS devices etc.

Within the FASTC methodology, automated contingency screening algorithms are used in operational and planning horizons that analyze the current operating case of the power grid, and optimize through all possible scenarios that identify critical network outages.

5.7 Time and Associated Factors

The current process of path transfer determination in planning and operational horizons is a very time consuming process as discussed earlier. This is largely attributed to the fact that large parts of the process are manual and require human intervention at all stages to correct the model.

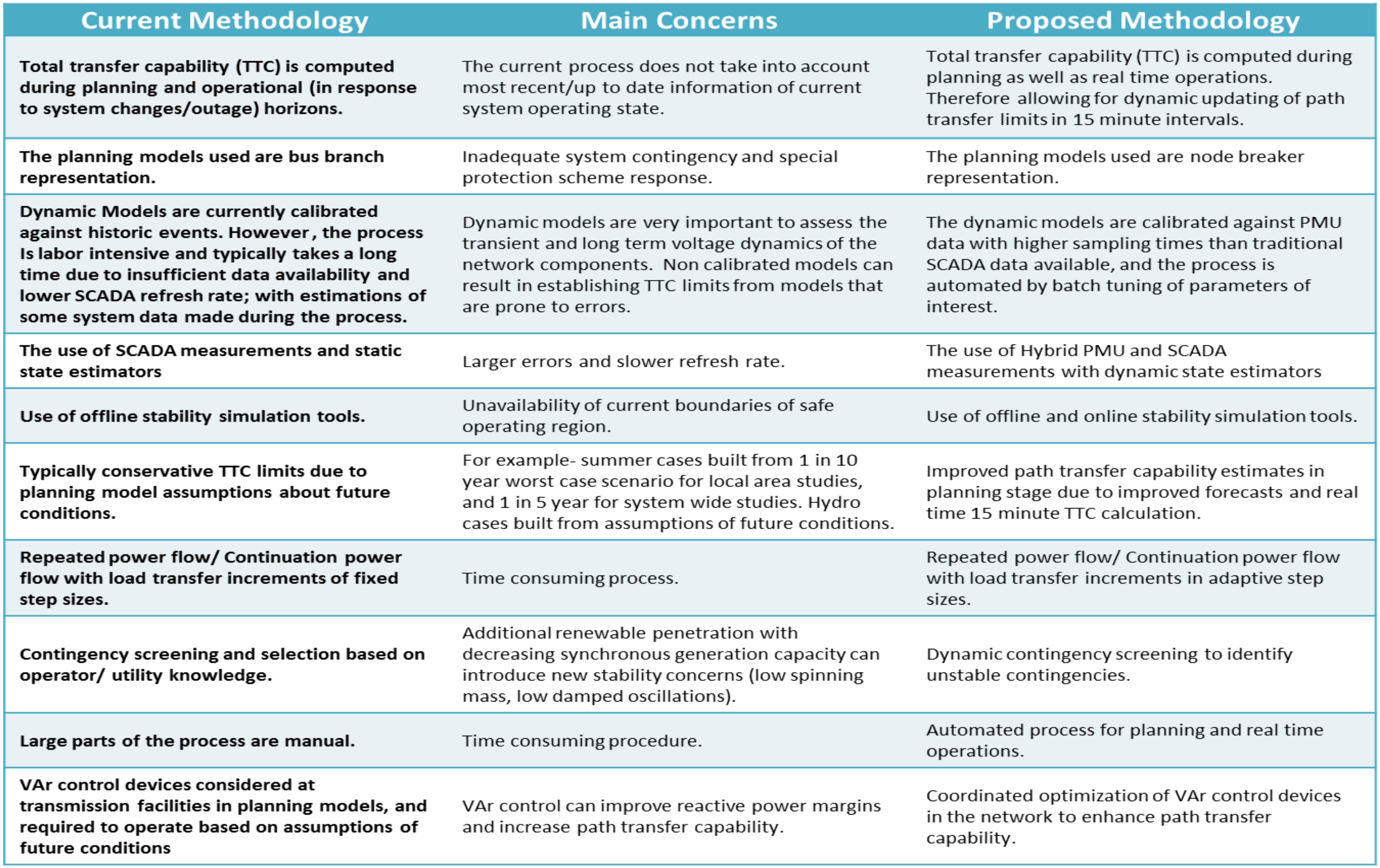
In the FASTC methodology, large parts of the planning and operational path transfer calculations are automated through processes that transfer the flow of data from one stage to the other.

5.8 Control Devices

In current process, VAr control devices are a part of the transmission facilities, and as such will be included in the determinate of transfer limits. NERC TPL standards require that planning studies model the system as it is expected to operate in the forward planning horizon.

In the FASTC methodology, the VAr control devices can be used to improve reactive power margins and increase transfer limits. This is brought about by coordinated optimization of control options in the network with a fixed objective to enhance network loadability. This will be enabled in a WAMPAC environment.

The discussion in earlier sections is summarized and presented in Figure 21 below.



Current Methodology	Main Concerns	Proposed Methodology
Total transfer capability (TTC) is computed during planning and operational (in response to system changes/outage) horizons.	The current process does not take into account most recent/up to date information of current system operating state.	Total transfer capability (TTC) is computed during planning as well as real time operations. Therefore allowing for dynamic updating of path transfer limits in 15 minute intervals.
The planning models used are bus branch representation.	Inadequate system contingency and special protection scheme response.	The planning models used are node breaker representation.
Dynamic Models are currently calibrated against historic events. However, the process Is labor intensive and typically takes a long time due to insufficient data availability and lower SCADA refresh rate; with estimations of some system data made during the process.	Dynamic models are very important to assess the transient and long term voltage dynamics of the network components. Non calibrated models can result in establishing TTC limits from models that are prone to errors.	The dynamic models are calibrated against PMU data with higher sampling times than traditional SCADA data available, and the process is automated by batch tuning of parameters of interest.
The use of SCADA measurements and static state estimators	Larger errors and slower refresh rate.	The use of Hybrid PMU and SCADA measurements with dynamic state estimators
Use of offline stability simulation tools.	Unavailability of current boundaries of safe operating region.	Use of offline and online stability simulation tools.
Typically conservative TTC limits due to planning model assumptions about future conditions.	For example- summer cases built from 1 in 10 year worst case scenario for local area studies, and 1 in 5 year for system wide studies. Hydro cases built from assumptions of future conditions.	Improved path transfer capability estimates in planning stage due to improved forecasts and real time 15 minute TTC calculation.
Repeated power flow/ Continuation power flow with load transfer increments of fixed step sizes.	Time consuming process.	Repeated power flow/ Continuation power flow with load transfer increments in adaptive step sizes.
Contingency screening and selection based on operator/ utility knowledge.	Additional renewable penetration with decreasing synchronous generation capacity can introduce new stability concerns (low spinning mass, low damped oscillations).	Dynamic contingency screening to identify unstable contingencies.
Large parts of the process are manual.	Time consuming procedure.	Automated process for planning and real time operations.
VAr control devices considered at transmission facilities in planning models, and required to operate based on assumptions of future conditions	VAr control can improve reactive power margins and increase path transfer capability.	Coordinated optimization of VAr control devices in the network to enhance path transfer capability.

Figure 21 : Comparison of current methodology vs proposed methodology

6 DEMONSTRATION ON WECC RATED PATH

The California – Oregon Interface (COI) was chosen to demonstrate the performance of proposed FASTC methodology. The results obtained from proposed methodology are compared to transfer limits obtained using current practices of determining path transfer limits.

6.1 California - Oregon Interface (COI)

The COI interface is one of the most commonly and widely studied WECC rated paths. It is commonly referred to as Path 66 in WECC literature. It is located between Oregon and Northern California.

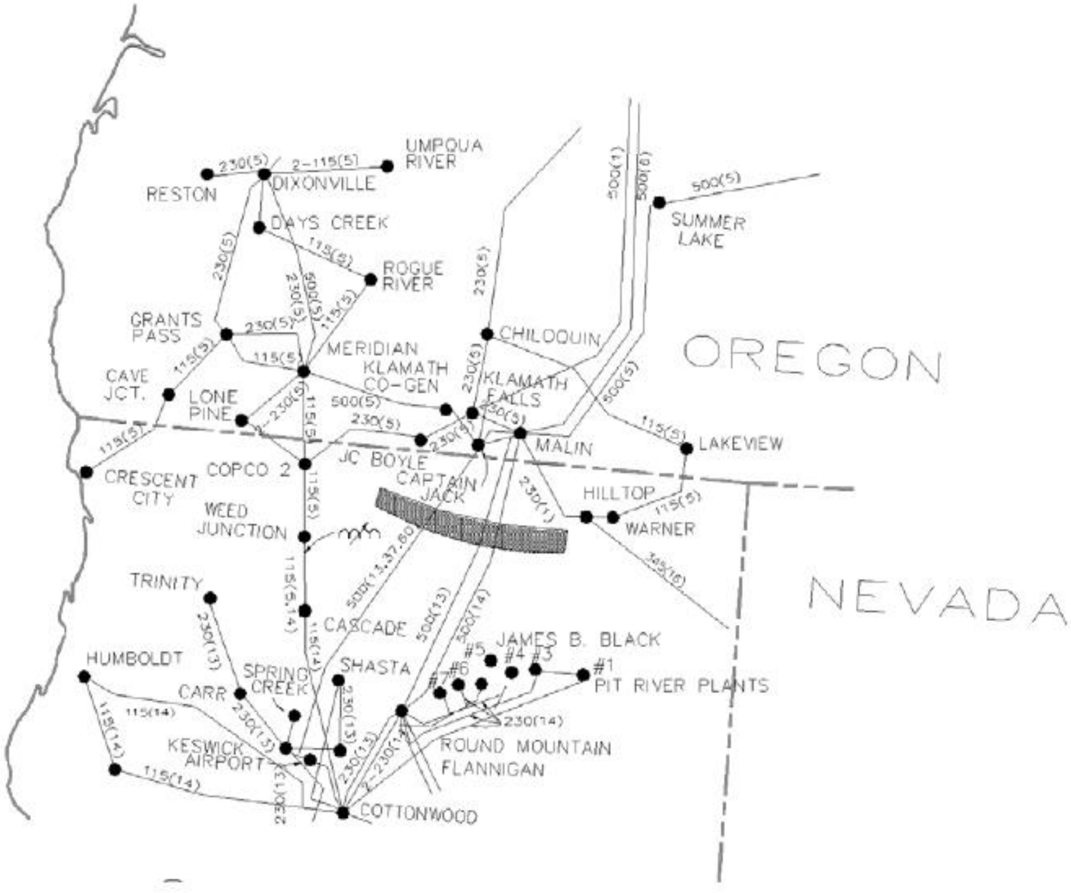


Figure 22: COI Interface

The path is defined by the following lines:

1. Malin to Round Mt. 500 Kv (2 lines) (Pacific AC intertie)
2. Captain Jack – Orinda 500 kV line (COTP).

As per WECC 2014 Path rating catalog, the transfer limit is imposed at 4800 MW from the North- South direction. The 4800 MW north to south rating was established in 1986 though the WECC Annual Progress report procedure. Progress reports have been submitted each year since 1992. The flows on this path are highly influenced by flows on other paths in including Pacific DC intertie (Path 73), Montana- Northwest (Path 8), Idaho Northwest (Path 14) and Reno – Alturas (Path 76). This path is operated as per BPA Standing order 306 and California ISO T 102 and T 120.

6.2 Assumptions and Study Considerations

In this demonstration, the following considerations and assumptions are made.

1. The base case considered for this study is the WECC 2014 Heavy Summer 4 Base Case. This case represents a 90-100% summer expected peak, with 100% summer expected peak in Northwest.
2. The initial base case information is as follows –

• Area 40 (Northwest) Export	• 4348.7 MW
• Area 30 (PG&E) Import	• -855 MW
• COI Flows	• 3765 MW

3. The initial base case was tuned to ensure all voltages are within acceptable range and scheduled power flows are exchanged. This tuning was performed using the following considerations.
    a. Generation re-dispatch in individual areas.
    b. Switching Static Var device status.
    c. Changing transformer tap settings.
    d. Generator VAr limit adjustment.
    e. Generator bus terminal voltage adjustment.

4. Each base case is assumed to represent a current operating state of the system network model as obtained from the state estimator.

5. The tools used in this process include

a. GE PSLF v 19.0 with its power flow data format (.sav, .epc), dynamics data format (,dyd)
b. MATLAB
c. Power Tech Tools (TSAT, VSAT and PSAT)
d. Microsoft Excel

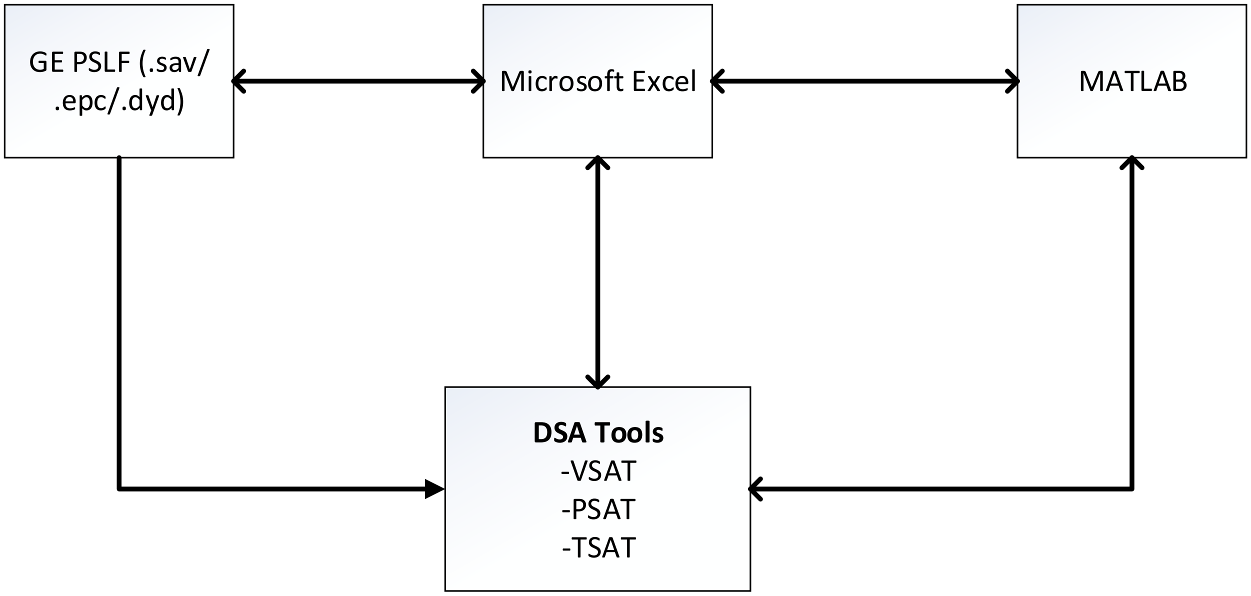
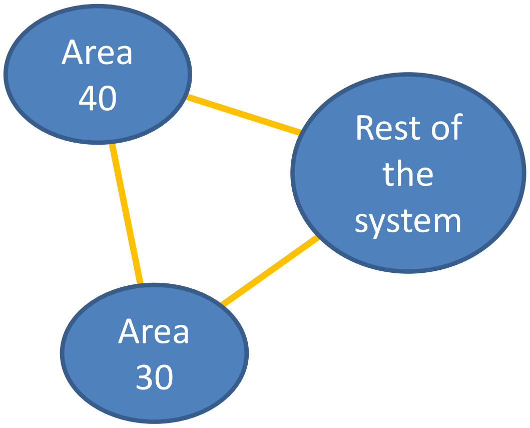


Figure 23 : Tools used for sample demonstration

6. The monitored elements include all substations and branches 100 kV and above operating within NERC TPL prescribed limits during pre and post- contingency conditions.

7. Source generation area considered to be Area 40 and Sink area considered as Area 30 as defined in WECC planning models.



8. All applicable RAS schemes were modeled as per WECC operating procedures WECC -1, and CAISO operating procedure T-102.

9. The initial user defined step transfer size considered 100 MW.

6.3 Current Methodology to Determine Path Transfer Limits

The current WECC methodology was used to determine path transfer limits. The various stages involved in this process included:

1. Multiple base cases were created with 100 MW transfer size increments. This is done by increasing generation in source area (Area 40) and simultaneously increasing loads in sink area (Area 30).
2. Each base case is analyzed in detailed to assess voltage stability and transient stability under loss of critical contingencies (discussed below). The NERC TPL and WECC reliability criteria area used to analyze system performance.
3. The loading is increased till secure operating point is reached at the boundary of system instability.
4. The operating parameters are plotted against considered stability limits to obtain nomograms.

The critical contingencies considered in this assessment are based on a thorough review of existing literature and Path operator manual (WECC Path Rating catalog 2014, WECC operating procedure -1). The considered contingencies are listed below.

- Loss of two Palo Verde units.
- DC Bipole outage.
- Table Mt- Tesla and Table Mt- Vaca- Dixon.

- Vaca Dixon - Tesla 500 kV
- Los Banos – Tesla 500 Kv
- Tesla – Tracy 500 kV
- Olinda – Maxwell - Tracy 500 kV
- Round Mt 500/230 kV Transformer Bank.
- Table Mt. – Vaca Dix 500 kV
-

The results obtained from current path rating process include:

- The maximum transfer rating is 4793 MW
- Limiting contingency identified as loss of two Palo Verde units
- Malin substation has reduced reactive power reserves closer to collapse point
- The applicable RAS schemes results in loss of 187.6 MW of load in Arizona area

In current practice, the results obtained are fixed and imposed as maximum transfer limits to be monitored during system real time operations. When system operating conditions are expected to change, the transfer limits are recalculated using planning models in the similar manner discussed above.

In the next section, the current methodology is compared to the proposed methodology and the results are plotted.

6.4 FASTC Methodology to Calculate Path Transfer Limits

The FASTC study methodology is presented below.

1. From the production cost model (PROMOD) high hydro case 2014, the load profiles for each Balancing Authority are extracted.
2. To create a series of operating conditions for path rating studies, the load profile at each bus is needed. Thus to reach a certain level of load in one BA, all the load buses in the area are uniformly adjusted. The different operating conditions are created to represent closer-to-real-time, dynamic system conditions.
3. To keep a balance between generation and load, the generation level in this area is also adjusted.
4. Active power outputs of generation units supplying base loads (ex, nuclear generators) are fixed, and excluded from generation adjustment.
5. In this manner, different operating conditions (referred to as operating states/cases) are created with converged power flow solutions to represent a series of conditions in the WECC region during the day when the peak load occurs.
6. Five operating cases are created in this manner, by scaling the loads and generation in different BA areas.

7. Assume all operating cases represent real time operating states of the system obtained from state estimator in real time available to operators and planning engineers.
8. Path transfer limits calculated for each of the above five operating points. These limits are calculated in the following two methods which are commonly used in practice-
    - Load – Generator Dispatch – This strategy is similar to discussed transfer direction of current methodology discussed in earlier section of report. In this strategy, at every transfer size, the load in sink area is increased (Area 30) and the generation in source area (Area 40) is increased.
    - Generator – Generator Dispatch –In this strategy, at every transfer size, the generation in sink area is decreased (Area 30) and the generation in source area (Area 40) is increased.

    Results from each dispatch strategy are compared to fixed WECC rated TTC values.

9. All algorithms discussed in earlier sections are run in parallel at every loading step, including contingency screening, system stability assessment, and adaptive RAS and Volt/VAr optimization. Results from each are applicable section are presented in upcoming sections of the report.

6.5 Results

The results discussed in this section include the “Base case analysis” along with Results from testing of individual components of the methodology presented through sections 6.5.1 to 6.5.3. Results from an additional case on the CAISO duck curve characteristics are also discussed.

The results in figure 24 compare Total COI path transfer results obtained from FASTC methodology against those obtained from the current methodology. These results are presented for a load – generation dispatch strategy.

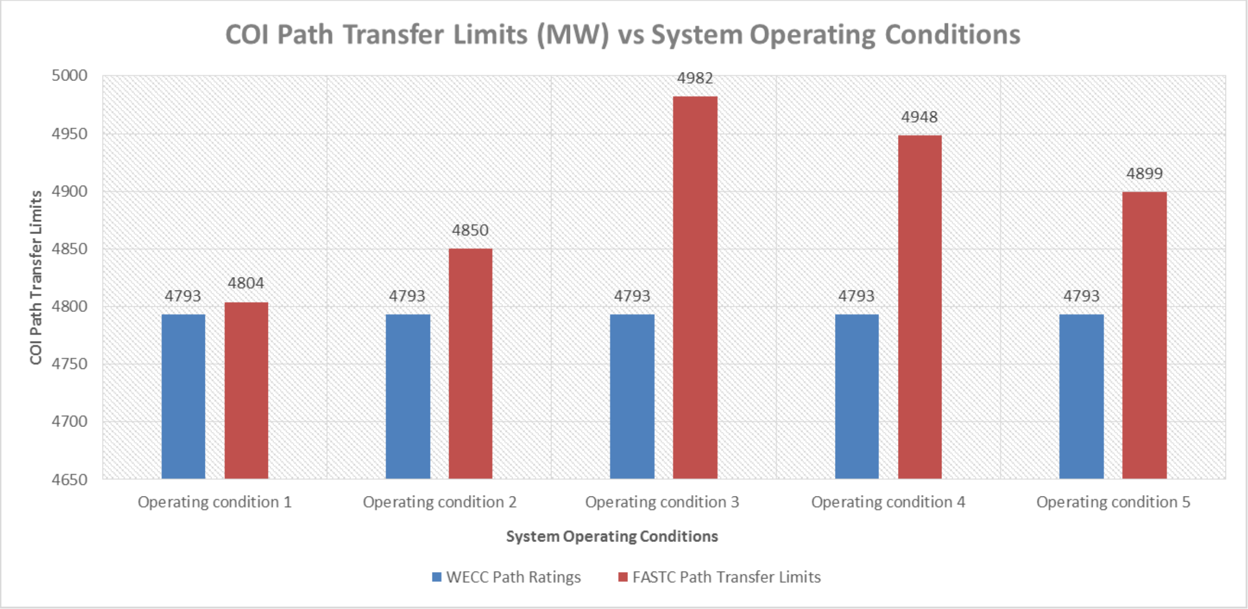


Figure 24 : COI Path Transfer limits vs Operating Point – Load Generation Dispatch

The results in figure 25 compare Total COI path transfer results obtained from the FASTC methodology against those obtained from the current methodology. The results are presented for a generation – generation dispatch scenario.

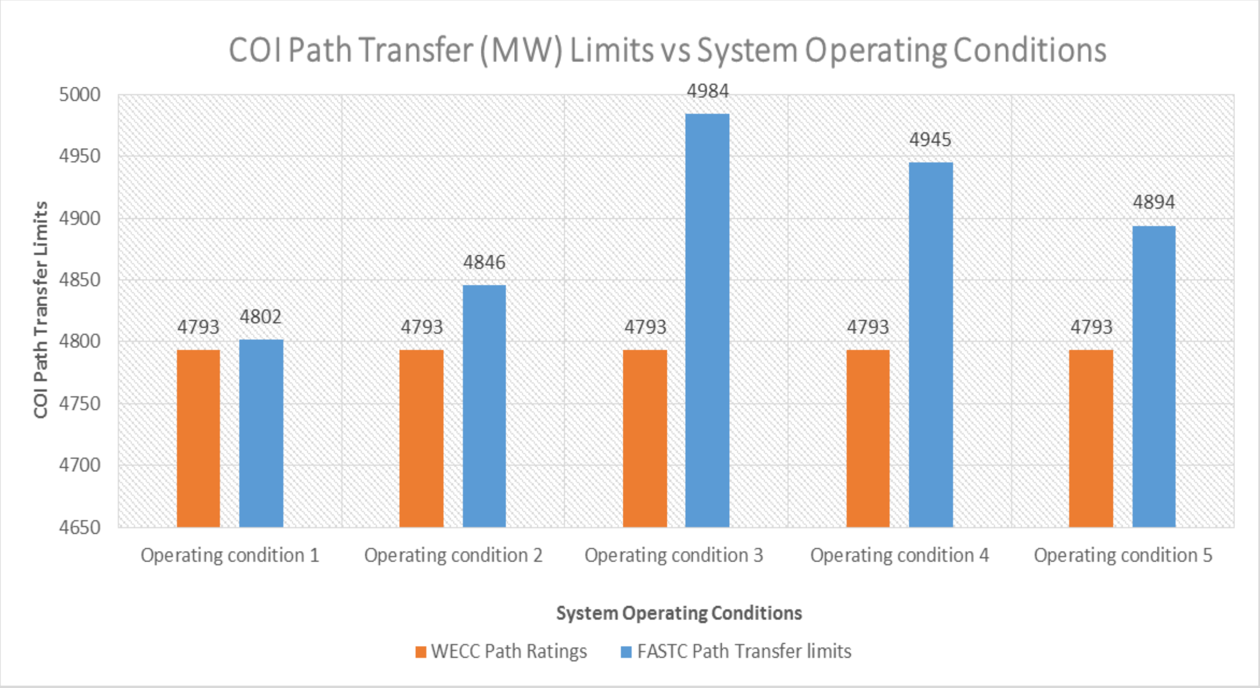


Figure 25 : COI Path transfer limits vs. Operating point – Generation – Generation Dispatch

As observed from the results obtained, the path transfer limits are dependent on current operating state of the system. The proposed methodology calculates the path transfer limits accurately, thereby allowing for improved asset utilization and trading opportunities. For considered base cases, the fixed path rating obtained can be considered as the conservative lower limit, however they do not reflect the true dynamics of power grid conditions.

Figure 26 summarizes the path transfer limits for each operating case. The differences between load- generator and generator – generator dispatch are negligible. The last column of the table shows the scaling factors used to create the five operating cases provided as an example, only for area 30 of the original case. The original load in Area 30 is 26,917 MW while generation is 26,999 MW.

Operating Point	Load Generator Dispatch Total Path Transfer capability (MW)	Generator Generator Dispatch Total Path transfer capability (MW)	Sample Area 30 Load Scaling from base case	Sample Area 30 Generation Scaling from base case
1	4804	4802	1.007	1.004
2	4850	4846	1.002	1.000
3	4982	4984	0.983	0.990
4	4948	4945	0.990	1.00
5	4899	4894	0.996	0.990

Figure 26 : Summary of case results

6.5.1 Contingency Screening and Assessment

In this section results obtained from real time contingency screening and assessment, of the new operating cases is discussed. The list below discusses the contingencies identified by the FASTC methodology.

- Loss of two Palo Verde units.
- DC Bipole outage.
- Table Mt- Tesla and Table Mt- Vaca- Dixon.
- Loss of two Diablo Canyon units.
- Vaca Dixon - Tesla 500 kV
- Los Banos – Tesla 500 Kv
- Tesla – Tracy 500 kV
- Olinda – Maxwell - Tracy 500 kV

- Round Mt 500/230 kV Transformer Bank.
- Table Mt. – Vaca Dix 500 kV.
- Hanford- Coulee 500 kV
- Ashe- Low Mon 500 kV.

The results indicate successful identification of critical contingencies reported by WECC operating procedures and other documentation from literature review. The online contingency screening algorithms successfully identify an additional three contingencies that seem critical under operating conditions represented by the developed cases.

The most limiting contingency that impacts flow on COI interface still remains the loss of two Palo Verde units.

6.5.2 Dynamic RAS

Adaptive and Dynamic RAS algorithms identify that higher path rating can be obtained for critical contingency (loss of two Palo Verde units) during path transfer calculations. The identified RAS scheme provided the following results –

1. Redispatch generation in Arizona and New Mexico.
    a. CORONADO Gen 1 & 2.
    b. MES –ST Gen 1 & 2.
    c. SPR GEN Gen 1& 2.
2. Drop 94 MW of load in Arizona.
3. Switch shunt status to ON at MEAD and MORENCI substations.

The results of Figure 27 demonstrate the impacts of dynamic RAS implementation during operating point 5 of the system. It is assumed that the operator allows the dynamic RAS algorithm to operate at this point in the network to improve the transfer capability. The same tool can be used by transmission planner’s offline.

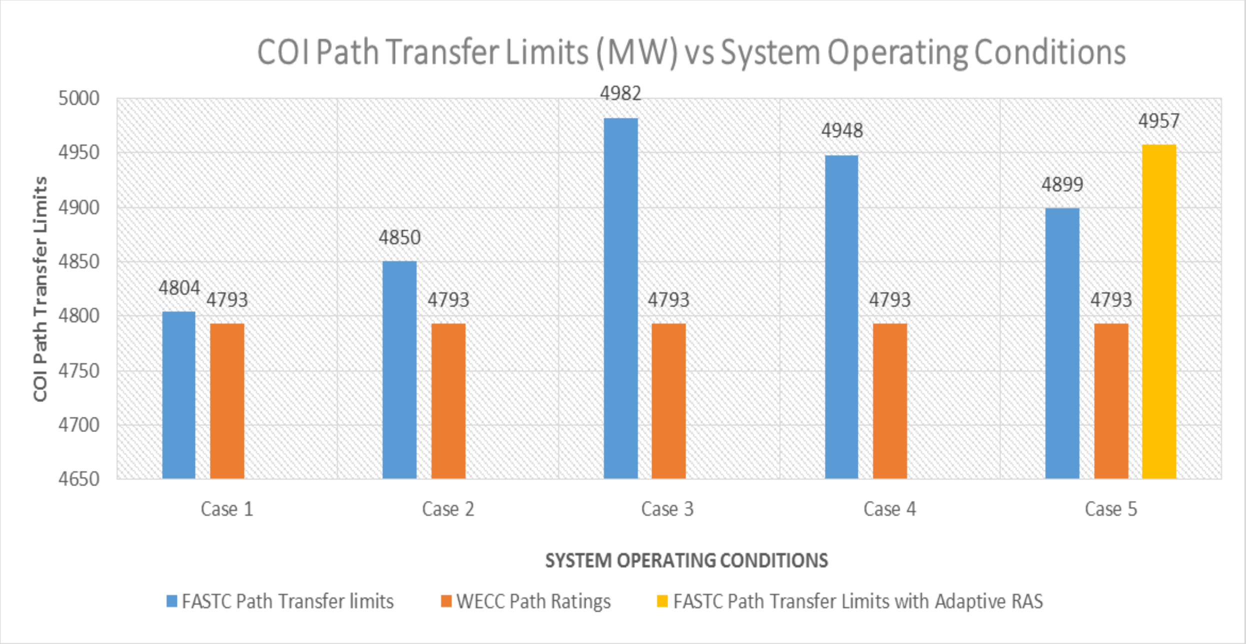


Figure 27: COI Path transfer limits vs operating point with Dynamic RAS

6.5.3 Volt/VAr Optimization and Control

Volt/VAr optimization and control algorithms can improve the path transfer limits at any given operating system condition by taking advantage of available control devices in the network. The considered devices for the sake of this demonstration include SVD devices and series capacitors.

COI interface flows were increased by approximately 30 MW by following adjustments post contingency.

1. Switch Shunts online at MALIN substation (2 *232 MVAr)
2. Include series capacitor online from TESLA to LOS BANOS 500kV line.
3. Include series capacitor online from GATES to DIABLE 500kV line.

Advances in WAMPAC will allow for smooth control and automation of various voltage and power flow network devices.

The results of Figure 28 demonstrate the impacts of Volt/VAr control implementation during operating point 2 of the system. It is assumed that the operator allows the Volt/VAr algorithm to operate at this point in the network to improve the transfer capability. The same tool can be used by transmission planners in an offline environment.

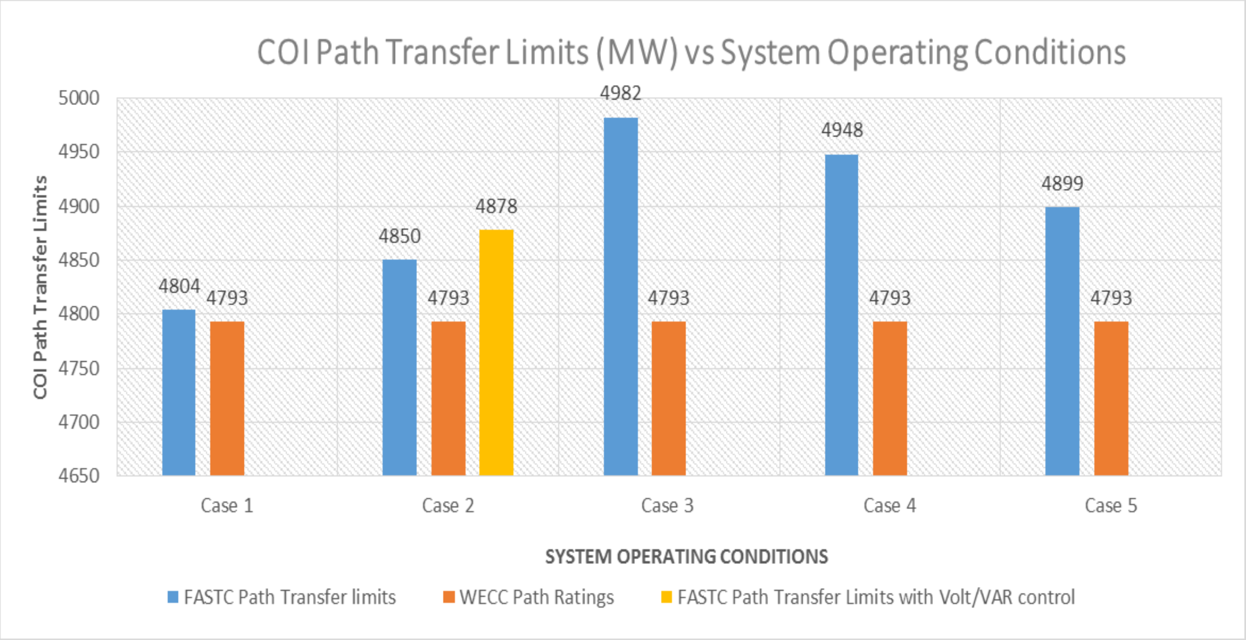


Figure 28 : COI Path Transfer limits vs Operating points with Volt/VAr control

6.5.4 FASTC Methodology: CAISO Duck Curve – Additional Case

In order to demonstrate performance of proposed FASTC methodology, another case was developed from the original 2014 high summer base case. The CAISO March 31 “Duck Curve” that represents fast ramping requirements in a high renewable penetration scenario was considered. The objective was to assess the impact of high ramping periods and varying operating conditions on COI interface path flows.

- Operating points were selected along the neck (ramp region) of the curve and cases were developed.
- The total load (not NET load) from duck curve was used.
- The difference between net load and total load was modeled as fixed generation.
- Load values were scaled into different zones within CAISO territory, including PG&E, SCE and SDG&E.
- Area wide Generation was scaled to adjust any imbalance and create converged power flow cases.

- Four operating cases were created to represent operating conditions at hour 3PM, 4 PM, 5 PM and 6 PM.
- Transfer limits are calculated using the FASTC methodology, and results are compared against results obtained from current path transfer determination methodology. Load – Generation Dispatch and Generation – Generation dispatch has been considered for this assessment.

Figure 29 below represents the original CAISO duck curve, along with a simplistic representation of the load increase (ramping pattern) plotted against hour of day (3PM to 6 PM) considered.

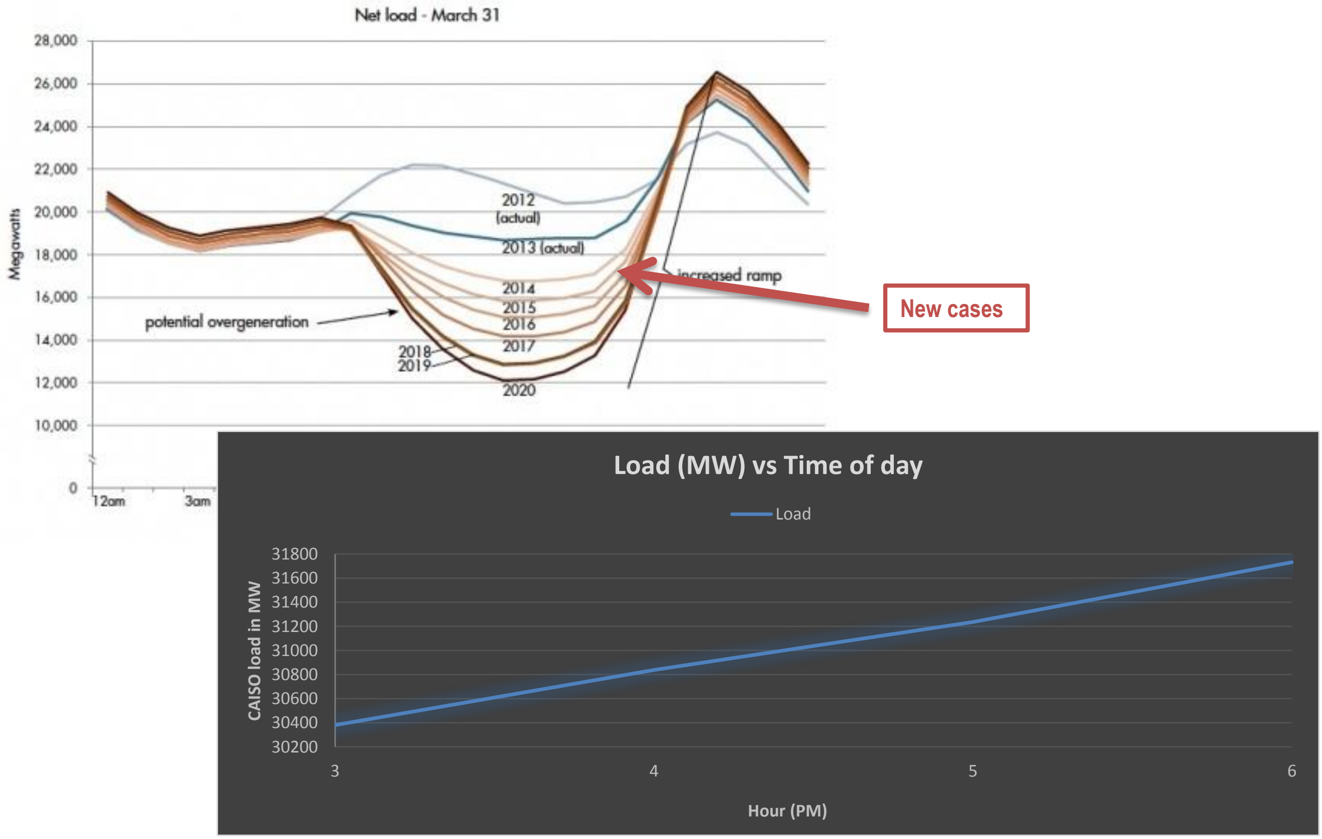


Figure 29 : CAISO Duck curve – Considered Load in MW vs Operating Hour.

Figure 30 demonstrates the results obtained from Generation – Load dispatch, representing COI path transfer limits using FASTC methodology and WECC path rating versus operating hours (3 PM to 6 PM).

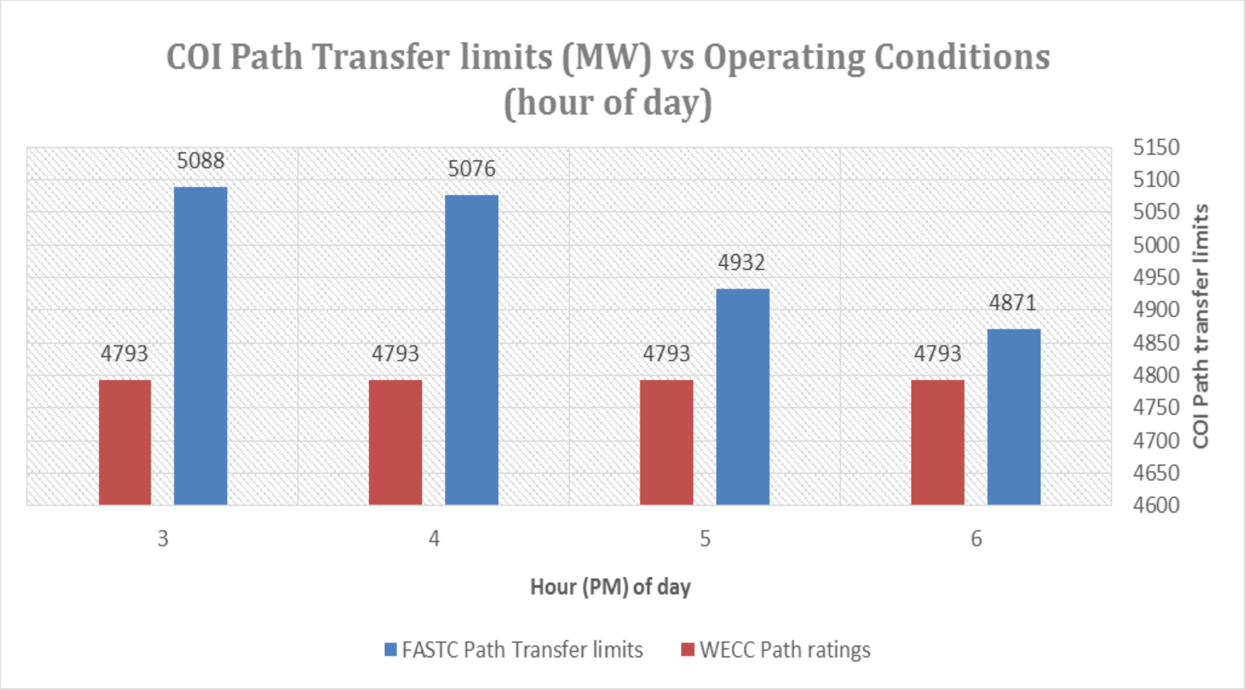


Figure 30: COI Path Transfer limits vs operating point –load Generation Dispatch

Figure 31 demonstrates the results obtained from Generation –Generation dispatch, representing COI path transfer limits using FASTC methodology and WECC path rating versus operating hours (3 PM to 6 PM).

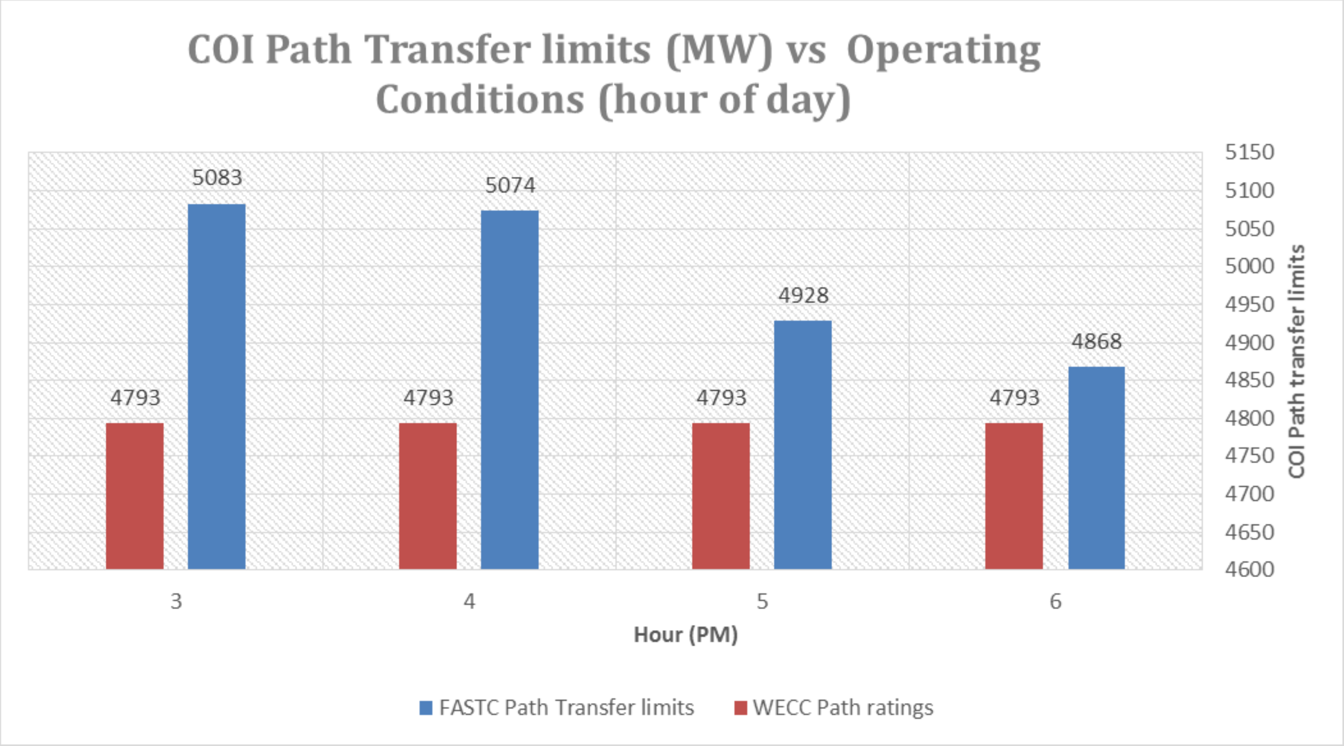


Figure 31: COI Path Transfer limits vs Operating Point (Generator – Generator Dispatch)

The results obtained demonstrate variability in path transfer limits that can be obtained during the course of the day based on the current operating state of the system. The change in loading within the area, with significant changes in the external system can contribute to either increasing or decreasing the path transfer limits. The proposed methodology addresses concerned with accurate computation of path transfer limits in real to near real time environments.

Figure 32 tabulates the results of load levels in CAISO territory and Path transfer limits obtained.

CAISO Load (MW)	Load Generator Dispatch Total Path Transfer capability (MW)	Generator Generator Dispatch Total Path transfer capability (MW)
31732	4871	4869
31236	4932	4928
30839	5076	5074
30392	5088	5083

Figure 32 : Summary of CAISO loads and Path Transfer limits

7 TECHNICAL HURDLES AND DATA ACCESS REQUIREMENTS TO BE RESOLVED FOR IMPLEMENTATION

In this section of the report, a discussion of the technical hurdles and data access requirements to be resolved for implementation of proposed methodology is provided. The biggest challenge that restricts implementation of proposed methodology is the available computing power and technology. Though available and within the reach of commercial organizations, trends are yet to evolve towards wider use of advanced computer technology. The challenges can be briefly summarized under the following categories:

1. Computing technology and requirements
2. Unified data models
3. Support for massive data
4. Operator training

7.1 Computing Technology and Requirements

The fundamental challenge that limits real time online path transfer calculations remain the restricted use of large scale computing power in today's control centers. With requirements to calculate and update path transfer limits within 10 to 15 minute intervals, control centers must take advantage of a combination of parallel computing power using multi core /hyper threading and large scale cluster machines. These technologies are used currently in large scale organizations, universities and research labs. They are considered well within the reach of control center operations.

The large computing power is associated with the needs to perform large scale dynamic stability simulations. Such a simulation aims to determine the time- series trajectory when the system is subject to contingencies and disturbances. There is a need to solve a large set of differential and algebraic equations that describe the dynamics of generators as well as other dynamic devices and their controllers. Current single processor computers are not suitable for real time environments due to slower speeds.

The computational process is shown in Figure 33 from PNNL High Performance Computing (HPC) research. A number of simulation cases need to be performed at each loading and transfer level. Serial computing uses only one central processing unit to perform all the simulations in a sequence, the total solution time increases when the number of contingencies or the number of iterations increase. This is the current practice and limits path transfer studies to offline environments.

Distributed computing has been used to speed up the computation of multiple contingency cases by distributing the cases to multiple computers, however the solution time for each case remains the same. So while performance can be improved, it does not address the issue of computation time.

The key is to reduce the solution time by parallel computing of individual simulation cases. With enough processors and scalable implementation of parallelized dynamic simulation, the total solution time can be kept short enough to enable real time path rating. This environment can be referred to as a high computing platform.

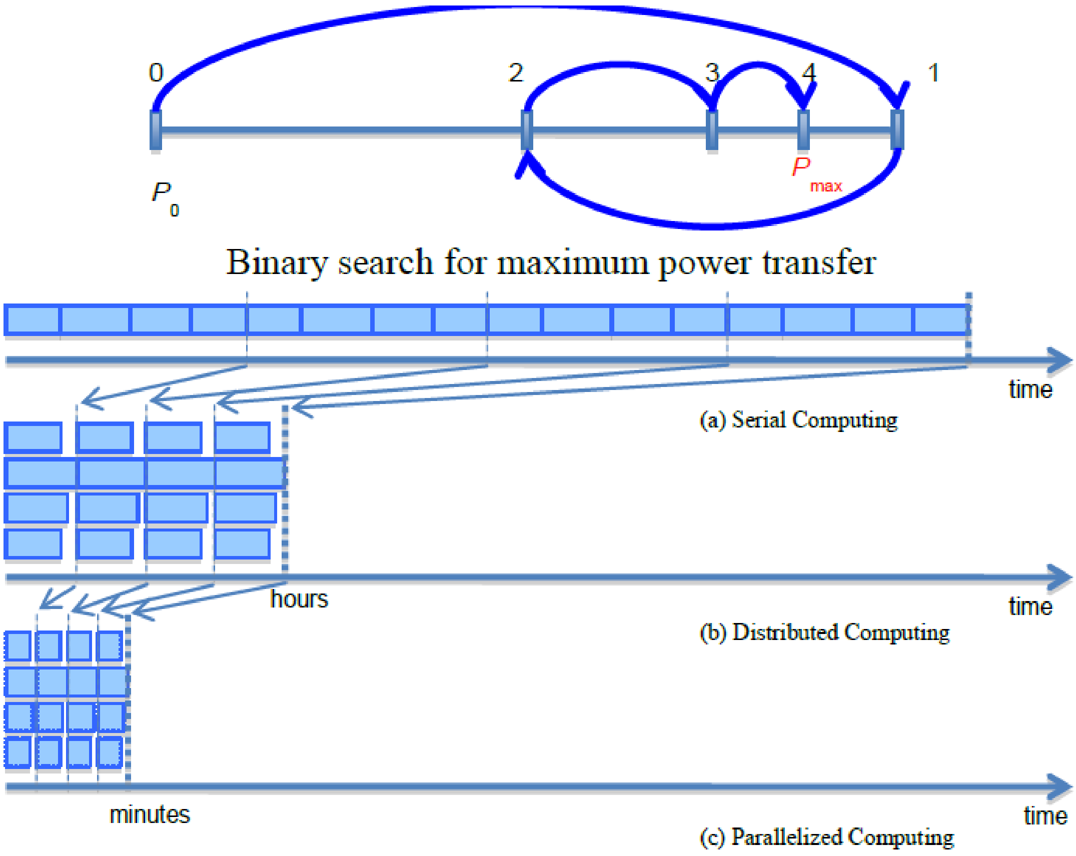


Figure 33 : Highlights of different computing technologies

High performance computing platforms generally include cluster machines with multiple cores available for parallel computing. Parallel computing platforms use scripts to control the work flow. For example, the Saguaro cluster at Arizona State University, has 4560 processing cores available for parallel computing. The cluster is composed on 570 dual quad core nodes, each with 16 Gigabytes of RAM. Each node communicates using high speed interconnects. The cluster can also include partitions for running a large number of serial jobs.

7.2 Unified Data Models

While the proposed methodology can work under the given structure of available models, unified models in which the divisions between operations and planning, and transmission and distribution network are eliminated or abstracted to the application are desirable. A significant portion of the EMS applications are arising at the continuum of scales from milliseconds (PMU) to week ahead.

The lack of unification of data models is a pervasive problem in the power industry. Various representations of a utility's power system network model can be found in a utility's EMS system: Input rational database, Real – Time Database, Internal Bus- Branch model, exported snapshot planning case (with varying bus numbers) and Common Information models. None of these models are compatible with planning case used in the offline environment.

Unified data modeling means that a common model is used across applications and across all relevant scales. For instance, Distribution Management system data should seamlessly be propagated into the EMS database, either at the point level or aggregated level.

7.3 Support for Massive Data

The data architecture must support high volumes of data from PMU, SCADA and smart meters. Models of these data must be compatible regarding geo- referencing, ID-ing, time – tagging and verification for the various application scopes. Machine learning and data mining applications are very promising tools currently in use to provide powerful analytics and discovery. As new technologies with data measurement capabilities are added to the system, it is imperative that the data architecture needs be flexible enough to support these data needs.

7.4 Operator Training

Operator training on new tools and processes can assist with better utilization of available transmission assets while effectively utilizing path transfer capability. Real- Time path transfer calculations introduce a variety of tools that operators need to be familiar with to take advantage of available enabling technologies.

While most features of the proposed methodology allow for seamless data transfer and automated analytics, interpretation of results and available information can assist the operator to make informed decisions while operating the power grid.

7.5 Cost of Implementation

As discussed earlier in earlier sections of this report, the implementation of FASTC methodology in planning or operational real time horizons make use of commercially available software, commonly used today. Some of the improvements in accuracy of planning based path transfer determination, depend on the use of data from real time operational horizon. The stages of developing scripts and tools to automate the planning based processes are more time consuming than costly.

Moving to the real time operational horizon, the nucleus of FASTC is controlled by the Energy Management System (EMS) in the control center. A few of their tasks include the capability to maintain dynamic network models in coordination with state estimators, perform reliability assessments in near real time and provide large scale system visualization capability. The cost associated with the ability of EMS to perform such operations boils down to the computing power available to the control center.

The environment referred to as a High Performance Computing (HPC) environment includes the use of cluster machines with multiple cores. This is to support the requirements of real time dynamic transfer ratings. Further these processing cores need to be made available for parallel processing in order to reduce computational time. The average cost of setting this environment could be in the range of five hundred to seven hundred, thousand dollars. This again depends on a number of factors. This cost would be reflective of a number of factors-

- Number of cores interconnected
- Parallel processing setup
- High memory storage requirements
- Communication requirements (high speed infiniband)
- Redundancy requirements of control center infrastructure
- Cyber security requirements
- Cost of implementing software/algorithms into the EMS architecture

The price figures provided are a very high level estimate and are far from accurate. This is because of existing infrastructure that exists within control centers that could also be used as a base or to build a HPC environment.

The availability of these technologies at modern control centers, in coordination with the rapid deployment of Synchrophasors can provide the required network model to implement FASTC methodology. The existing PMUs and SCADA measurements that currently support the network model at control centers, can also be used to implement FASTC.

APPENDIX A: LITERATURE REVIEW

As discussed earlier, a complete strategy would include path transfer calculations during planning stages as well as operational stages. A brief summary has been presented below of algorithms that find application in real time operational and planning horizon path transfer calculations, relevant to the proposed methodology and current industry practices. One of the key aspects of this summary include identifying current limitations to the process and addressing them within reasonable scope of a 5 year deployment strategy.

- Bridging the differences between EMS based full topology model and planning based consolidated topology models begins with having a node breaker representation of the entire network. If the planning case had information about nodes, breakers, and breaker statuses, it would be possible to move a step closer to replicating accuracy of real time power flow. This will allow for more accurate contingency impact analysis and system state representation. Most commercial software tools now include this capability

- Extensive work is being performed on model validation. The standard technique involves benchmarking against actual system performance during disturbance events or against existing WECC dynamic models and PMU recorded data. The recorded data is played back into the dynamic models and calibrated using curve fitting technique/component tuning. This will include tuning of generator parameters, load model parameters, reactive compensation devices etc. Current practices discussed in literature include use of Extended Kalman Filter, Genetic Algorithm, and Particle Swarm Optimization and Rule Based Parameter calibration. However a more effective strategy could be use of sensitivity analysis to identify critical parameters that have greater impact model mismatches and then develop a group based tuning of parameters.

- Current practices for TTC determination include Continuation Power flow techniques, Optimal Power flow and Linear Approximation methods. An effective strategy is to use a Continuation Power flow based adaptive control stage which will include a simulation that will adjust the transfer step size based on the response of the previous iteration. This technique is used quite commonly, even in voltage stability analysis. This package can be configured into commercially available tools as well.

- The fast dynamic contingency screening algorithm is an application that will take advantage of optimization algorithms to identify the most critical locations and screen out contingencies that are definitely stable. Most common research in this area uses heuristics, BCU method (Boundary of stability region based controlling unstable equilibrium point), energy function, pattern recognition and single machine infinite bus methods. This is a very critical stage to the online Voltage stability and Transient stability assessment. The best strategy is to combine a hybrid of direct methods with time domain methods. The list of unstable contingencies obtained from direct methods are moved to the time domain tool where they are further evaluated and additional control actions can be taken.

- Volt/VAr device optimization is a field that has been extensively researched. This will include use of Heuristic Algorithms such as genetic algorithm, simulated annealing, or tabu search to optimally tune these devices to meet the objectives of enhanced loadability. Different dimensions of this program will allow the user to even optimize locations that enhance network loadability. With the onset of Wide Area Monitoring, Protection and Control (WAMPAC) systems, the real time operations can benefit to a large extent with this control mechanism.

- The voltage stability and transient stability module can belong to commercially available tools that will perform these assessments for the set of defined contingencies. The path transfer capability will be identified as the limiting value of the MW flows as a result of instability detections made by this program. V&R energy and DSATools are examples of common real time application processors. Another area of stability determination commonly found in literature includes the use of prediction algorithms that make estimates of a look ahead load margin using commercially available tools with load forecast data. This data will be stored in a repository and its accuracy will be improved at every stage based on measurements obtained in real time. PNNL is conducting extensive research in this area to predict look ahead system stability.

- Forecast data profiles are generally available from Reliability coordinators and load balancing authorities to build future models. Currently non- linear regression models, which include neural networks and bagged regression trees are commonly used for this purpose. The aim is to improve forecast estimates in lieu of larger repository of real time smart meter / Advanced Metering Infrastructure (AMI) data being collected. To minimize the error between estimates and actual measured demand, linear least square method would be best suited.

- Considering a five year deployment scale, hybrid PMU and SCADA measurements are more of a possibility within this realm. Current State estimators largely use linear least square state estimators. Weighted least square state estimators are becoming available in near future. The difference in sampling times of PMU and SCADA data have been addressed by most commercial EMS systems. These state estimators are largely static in nature. Dynamic state estimators that use only PMU measurements remain an area of extensive research.

APPENDIX B: REFERENCES

- NERC Report (1996). Available Transfer capability definitions and determination. *North American Electricity Reliability Council.*

- WECC Report (2001). Determination of Available Transfer capability within the Western Interconnection, *Western Electricity Coordinating Council.*

- WAPA OATT- Attachment C. Methodology to assess Available Transfer Capability. *[Available]:* www.**wapa**.gov/transmission/oasis.htm

- WECC Guideline (2012). Project Coordination and Path Rating Processes. *Western Electricity Coordinating Council.*

- WECC Report (2014). A New Paradigm for Path Operations. *Western Electricity Coordinating Council.*

- NERC Report (2013). White Paper on MOD – A Standards, *North American Electricity Reliability Council.*

- NE –ISO (2008), Automated Total Transfer Capability , Power World Users- group meeting, *[Available]:* www.**powerworld**.com/files/Maslennikov**AutomatedTTC**.pdf

- Singh, R.; Diao, R.; Niannian Cai; Zhenyu Huang; Tuck, B.; Xinxin Guo, "Initial studies toward real-time transmission path rating," *Transmission and Distribution Conference and Exposition (T&D), 2012 IEEE PES*.

- PJM Outage Analysis Automations, IEEE GM 2014. *[Available]:* http://resourcecenter.ieee-pes.org/conferences/2014-gm-super-session-pjm-outage-analysis-automations-video/

- Kaci, A.; Kamwa, I.; Dessaint, L.A.; Guillon, S., "Synchrophasor Data Baselining and Mining for Online Monitoring of Dynamic Security Limits," *Power Systems, IEEE Transactions on* . 2014

- Power-World, Topology processing and Real Time applications. *[Available]:* www.**powerworld**.com/files/GrijalvaRealTimeApps.pdf

- *GE PSLF V19, [Available]:* http://www.geenergyconsulting.com/pslf-re-envisioned.

- NASPI, Model Validation using Synchrophasor Data – A success story. [*Available*]: https://www.**naspi**.org/File.aspx?fileID=1341

- NERC Report (2010), Power System Model Validation, *North American Electricity Reliability Council.*

- A.A. Hajnoroozi, F. Aminifar, H. Ayoubzadeh, “Generating Unit Model Validation and Calibration Through Synchrophasor Measurements," *Smart Grid, IEEE Transactions on*.
- Jinquan Zhao; Hsiao-Dong Chiang; Hua Li, "Enhanced look-ahead load margin estimation for voltage security assessment," *Power Engineering Society General Meeting, 2003, IEEE* , July 2003
- V&R Energy, Vaiman, M.Y.; Vaiman, M.M.; Gaikwad, A., "Fast fault screening methodology for transient stability analysis of bulk power systems," *Power and Energy Society General Meeting (PES), 2013*
- H.D. Chiang, “Direct Methods for Stability Analysis of Electric Power Systems: Theoretical Foundations, BCU Methodologies, and Applications”, ISBN: 978-0-470-48440-1 Wiley Publications, 2011.
- E. Vaahedi, “Practical Power system Operation”, ISBN: 978-1-118-84863-0, Wiley Publications, 2014.
- H.D Chiang, “A (Smart) Real time PMU- assisted Power Transfer Limitation Monitoring and Enhancement System”. *[Available]: www.resnick.caltech.edu/docs/sg_chiang.pdf*
- Westermann, D.; Sauvain, H., "Experiences with Wide Area Coordinated Control of Facts Devices and HVDC in a Real Time Environment," *Power Tech, 2007 IEEE Lausanne*, 1-5 July 2007.
- A.J Wood, B.F Wollenberg, G.B. Shelbe, “Power Generation, Operation, and Control”, 3rd Edition, ISBN: 978-0-471-79055-6, 2013.
- Quilumba, F.L.; Lee, W.-J.; Huang, H.; Wang, D.Y.; Szabados, R.L., "Using Smart Meter Data to Improve the Accuracy of Intraday Load Forecasting Considering Customer Behavior Similarities," *Smart Grid, IEEE Transactions on.*
- P. Mirowski, S. Chen, T.K. Ho, C.N. Yun, “Demand Forecasting in Smart Grids”. [Available]: https://cs.nyu.edu/~mirowski/pub/Mirowski_BLTJ2014_DemandForecastingSmartGrids.pdf.
- Gol, M.; Abur, A., "A Hybrid State Estimator For Systems With Limited Number of PMUs," *Power Systems, IEEE Transactions on*.
- A. Abur, “Phasor- only State Estimation”, [Available]: http://www.pserc.wisc.edu/documents/general_information/presentations/pserc_seminars/psercwebinars2014/Abur_PSERC_Webinar_10-7-2014_Slides.pdf.
- Z. Huang, N. Zhou, Y. Li, P. Nichols, S. Jin, R. Diao, and Y. Chen, “Dynamic paradigm for future power grid operation,” in Proceeding 8th Power Plants Power System Control Symposium, 2012.

- PNNL, Look Ahead Dynamic Simulation, [Available] http://eioc.pnnl.gov/research/hpc_simulation.stm
- Y. V. Makarov, J. Ma, and Z. Y. Dong, “Non-iterative method to determine static stability boundaries,” in Proceeding IEEE Power Tech, Lausanne, Switzerland, Jul. 2007.
- DSA Tools, Renewable Energy Impact Assessment. [Available]: http://www.dsatools.com/downloads/Renewable%20Energy%20Impact%20Assessment.pdf
- Coordination and Path Rating Processes (https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/NDA/Project%20Coordination%20and%20Path%20Rating%20Processes.pdf&action=default&DefaultItemOpen=1)
- WECC Path Concept White Paper (https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/Path%20Concept%20Whitepaper.pdf&action=default&DefaultItemOpen=1)