MODULAR CONTROLLABLE TRANSFORMERS (MCT)

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Table of Contents

SECTION 1.0 ACKNOWLEDGEMENT AND DISCLAIMER

Acknowledgement:

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SECTION 2.0 ABSTRACT

Large Power Transformers (LPTs) are at the heart of the electricity infrastructure and are critical pieces in today's grid. Aging assets, long turn-around times, transportation delays and dependence on foreign manufacturing for these components have created conditions for points of failure across the system. Moreover, there is no available dynamic control on these passive sections of the grid. For all the automation embedded on the low voltage side of the low voltage side of the system there is absolutely no flexibility on the high voltage side. Changes in power flow patterns are brought about by altering dispatch patterns for generators which requires a coordinated effort and is often time consuming. Traditional FACTS based approaches such as UPFC or HVDC light involve massive modifications to the existing infrastructure. Recent instances of physical attacks on LPTs and the slow recovery process associated with fixing or replacing these damaged units has created an increased awareness for this issue. LPT designs are highly customized owing to specific field requirements. Long lead times coupled with transportation delays make procuring and installing LPTs a lengthy process.

In an attempt to minimize the recovery time following an LPT failure, transformer manufacturers have developed mobile transformer units. These units typically consist of either a single-phase or three-phase transformer mounted on a truck and characterized by compact form factors. By reducing the assembly time and transport time these units offer a fast and temporary solution to LPT failures. Several efforts led by DOE, Edison Electric Company (EEI) and North American Electric Reliability Corporation (NERC) have led to the RecX program. RecX transformers consist of single phase transformers transported on specialized assemblies to enable fast restoration and minimal installation time. NERC and EEI have instituted transformer sharing programs like Spare Equipment Database (SED) as well as Spare Transformer Equipment Database (STEP) which encourage utilities to maintain and share a fleet of LPTs. Mobile transformers are typically limited to less than 100 MVA to enable transportation on a trailer. Also, the efficiency of mobile transformer units and RecX transformers is lower since they are temporary solutions. The ideal replacement solution would be one that could utilize a set of standardized transformers while incorporating flexibility to influence metrics like power flow, apparent impedance and voltage profiles.

In view of these issues the team at Georgia Tech proposed a concept called Modular Controllable Transformers (MCTs). This project was commissioned as a part of DOE's Transformer Resiliency and Advance Component (TRAC) program. The approach consists of splitting one large unit rated upwards of 100 MVA with smaller modular, standardized units. Each of these smaller units are augmented with a converter to add power flow, voltage and impedance control. Splitting the power level into multiple units has two important implications. By making smaller units, the transportation times can be reduced drastically. Moreover, even though these units have very specific impedance and other parameters, the augmented converters can make it emulate the unit being replaced. Thus, faster replacement times and added controls are achieved making this an extremely resilient approach. In the event of one modular units failure, the other two controllable units can operate in the most resilient fashion keeping the net system overloads to a minimum. Moreover, for the same probability of failure only a fraction of the system capacity is lost. The converter is augmented on to the tertiary winding of the transformer making it

retrofittable in the field without massive modifications to the system. The material proposed in this report highlights design considerations to minimize recovery time as well as results displaying overall improvement in resiliency. The cost analysis of this approach shows significant savings compared to UPFC and HVDC lite based approaches.

Extensive analysis was conducted on numerous aspects of this project over the course of this project. Simulation studies were conducted to prove the 5MVA converter design. Challenging BIL constraints and transient issues were addressed over the course of this project. Simulations on EMTP platform presented in consequent sections were used to finely tune the control for the same. A final design for a back-to-back 5MVA neutral-point-clamped (NPC) converter was completed in this project. Furthermore, switching components like high power IGBTs from IXYS Westcode Press-Pack series and ABB Stackpack series were identified for this application. These devices exhibit a blocking voltage of 6.5 kV and a nominal collector current of 900 A. Potential housing options as well as existing commercial option were identified for this converter design. A 56 MVA modular transformer unit was designed with Delta Star Inc. with consultation and inputs from all project members. The transformer cooling systems were chosen to be Oil Natural Air Forced (ONAF) to optimize ease of transport. A full Product Requirement Document (PRD) for the converter and the transformer was generated. The team also investigated key aspects of resiliency and how to quantify the same. A metric was developed to analyze resiliency and numerous simulation cases were presented. Increased (N-1) resiliency and outage resistance was showcased through simulation on the Texas Large scale power system. Dynamic control capabilities were also showcased on numerous system level simulations. An IEEE 30 bus system was used to show the ability of the MCT approach to reduce line congestion. Power flow control; a part of the MCTs abilities, showcased a 29% reduction in transformer loading on the same system. Full control over tie line flows was demonstrated on a modified IEEE 13 bus system. Dynamic LTC capabilities were shown through simulation and were compared to traditional LTCs. Furthermore, the ability of the MCTs to alter apparent transformer impedance was simulated to promote standardization of modular transformer units while retaining the ability to emulate a varied range of impedance characteristics. Thus granular control over power flow, voltages, impedances and was presented. Regulatory analysis conducted by Oak Ridge National Laboratory (ORNL) further bolstered the efficacy of the MCT approach and verified the added resiliency achieved due to this approach. As a conclusion, it was proved that the resilience improvement obtained from using the MCT approach is justified by just one failure in a 30-year period. This means that the benefits obtained from using the MCT approach far outweigh the cost of setting this approach up.

As a part of the future efforts, the team is proposing building a (12.47-24) kV/400 kVA scaled down unit to control 5MVA of power flows. Emphasis would be laid on using commercial components to speed up the build of these units. Further the actual transport of the modular transformer unit would be a part of this operation and would provide insight into transportation issues. The approach shows much promise and adds key dynamic control on passive sub transmission and transmission sectors.

SECTION 3.0 PROJECT MILESTONE LOG:

Number	Description	Due date (Start date 01/01/2017)
M1.1	**Revised project management plan submitted to DOE** Submitted on reporting date	04/01/2017
M1.2	**Development of product requirement document (PRD):** A preliminary product requirement document was generated and submitted at the end of quarter 1. A finalized PRD is presented for the target ratings is presented in this document.	04/01/2017
M1.3	**Development of simplified models of MCTs to perform system analysis** A frequency domain model was generated for system level simulations and steady state analysis. A variety of system level simulations are conducted showcasing the range of control obtained using the MCT approach.	07/01/2017
M1.4	**Verification of MCT function through time-domain analysis** Time domain analysis on the converters topology is presented. The sizing for the required components is also presented in this document.	06/01/2017
M2.1	**Develop system resilience metrics** Resiliency metrics are developed and resiliency improvements are showcased on numerous large systems through use cases.	04/04/2017
M2.2	**Preliminary Transformer design** A PRD for the transformer is presented. The team has successfully developed the plan for a prototype transformer that is rapidly deployable. The detailed specifications for this unit and its structure are presented in the following sections.	07/01/2017
M2.3	**Preliminary Converter design**	07/01/2017

	A PRD for the converter is developed. The components required for this application have been appropriately sized and picked.	
M2.5	**Understand regulatory issues, role of FERC and NERC-CIP in rollout of MCTs, storage, transportation, resiliency, etc.** Detailed regulatory analysis has been conducted by ORNL and presented in this report. Numerous regulatory aspects of the MCT approach are highlighted in this document.	12/30/2017
M3.1	**Feedback from Utilities and transformer manufacturers on transformer and converter design** Feedback from Southern Company drove the final ratings for the target application. Owing to the presence of numerous 112 MVA (115/46 kV) units in Southern's system this application was chosen. Inputs from Delta-Star pointed towards designing modular 56/66 MVA units.	10/01/2017
M3.2	**Develop resilience improvement detailed simulations for a set of use cases** Resiliency improvement has been shown on multiple synthetic cases. A clear improvement in overall resiliency is shown in this document.	10/01/2017
M3.3	**Estimate the overall cost of MCTs under Option 1 and Option 2, including the possibility of smaller, standard and modular MCTs under Option 2.** Cost analysis was conducted for both possible options. It shows that at roughly the same cost as that of replacing an entire LPT, the modular approach provides added control, improved resiliency, higher revenue and redundancy across the system.	10/01/2017
M3.4	**Investigate system impacts of two options for system deployment** **i. Option 1: Retrofit MCT in existing substation as replacement to existing LPT** **ii. Option 2: Future grid design with higher resiliency, reliability and control using dispersed multiple smaller MCTs as a replacement for a single large MCT** The report and analysis shows that while the added control is the same for both options, option 2 shows more resiliency and redundancy. Moreover, more flexibility within the smaller modular units enables numerous revenue streams. For the same	10/01/2017

	probability of transformer failure only a fraction of capacity is lost.	
M4.1	**Final MCT design (Transformer and converter) completed.** The final design for both the transformer and converter for the target application has been developed.	10/01/2017
M4.2	**Estimate economic impact under typical 'black swan' events that can be mitigated with the use of MCTs.** Numerous use cases are presented here to showcase resiliency. Significant reduction in cost under black-swan events is seen here through simulations.	12/31/2017
M4.3	**Tech –to-market plan finalized**	12/31/2017
M4.4	**Final report** This document is part of the deliverable	12/31/2017

SECTION 4.0 ACCOMPLISHMENTS

4.1 Major goals

The major goal of this project is to design a modular controllable transformer (MCT) and show that the approach of realizing LPTs with small and standardized MCT units can improve grid resiliency.

4.2 Accomplishments

The following document reports on the progress made in the course of this project. The miles tones are summarized in the preceding table. Salient issues addressed include but are not limited to:

- Design modular controllable transformer consisting of a standardized transformer and a fractionally-rated converter such that a LPT can be realized using small standardized MCT units.
- Demonstrate resiliency improvement through detailed simulations for a set of use cases
- Perform cost analysis for the MCT approach.
- Investigate system impacts of the MCT deployment.
- Regulatory impact of the MCT approach.

4.3 Background

The electricity infrastructure as it currently stands has largely been designed over a 100 years ago. Aging oversized technology has created the need to understand and analyze solutions towards reducing the criticality of certain pieces of infrastructure scattered across the system. Owing to this there has been an increasing concern towards failure of Large Power Transformers (LPTs) which have been identified as a critical piece of infrastructure in their current state. LPTs are large custom-made devices that cost billions of dollars and weigh 300-400 tons making their product replacement process significantly different from most commercial product process models. Failure of a single LPT can potential cripple certain parts of the grid creating a situation where a large number of customers may go unserved.

Improving grid resiliency has been the prime motivation towards pursuing the LPT failure problem. The large turnaround time in terms of bidding for a replacement LPT and manufacturing it is significant enough to consider rapidly available solutions.

4.4 State of Art Approaches

Resiliency has often been defined in different ways. One of the approaches towards tackling the LPT failure problem has been to improve the recovery and response time in such situations. The primary considerations here have been the enormous transport time and facilities needed to move these bulky units across locations. The approach has been minimizing the transport time by using smaller rated units that can be moved easily across locations. Delta-star has actively contributed towards this by creating a mobile transformer unit that can be moved fast, such as one shown in **Error! Not a valid bookmark self-reference.**. Issues such as filling oil, commissioning, voltage derating/rating have been addressed here as well.

Figure 1: Delta Star Mobile Transformer

DOE and ABB initiated a similar RecX program. RecX transformers have demonstrated the ability to replace LPTs in record times. However, these attributes do not come without significant drawbacks. Mobile transformers typically operate at higher power densities making the losses higher. Also, these transformers have been designed keeping a universal application in mind. This manifests itself in the form of a transformer impedance which varies with loading level thereby impacting the loading on other transformers across the grid, as shown in Figure 2 . Uncertainty in terms of this loading presents a degree of risk in using these units as replacements. The primary takeaway here is that while the response and recovery time has been minimized, the system isn't truly resilient.

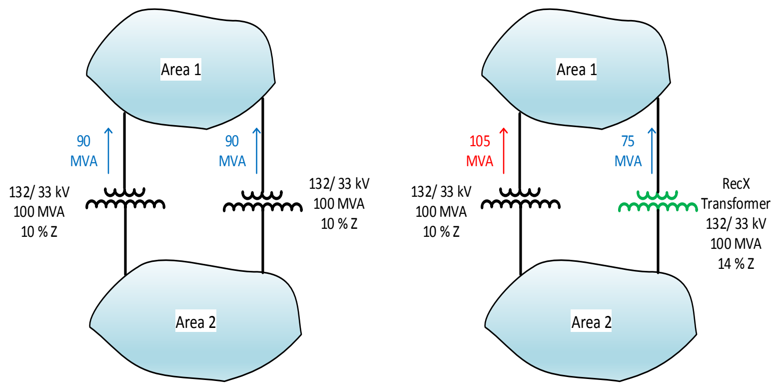


Figure 2: RecX Transformer issues

Another solution towards tackling this problem has been creating a spare equipment database which deals with maintaining a reserve for certain critical units which can be shared by a consortium of utilities. However, owing to the varying nature of the transformers and their characteristics it becomes infeasible to maintain a spare for each kind of transformer in the network. The motivation behind this project has been to propose a sustainable solution to increase grid resilience while achieving greater standardization so as to ensure faster recovery time [DOE FOA objective].

4.5 Proposed Approach

The team at Georgia Tech has proposed a concept to achieve greater standardization while increasing the modularity of the system. The approach here would be to embed some controllability into areas which were traditionally considered stiff and oversized so as to dynamically stabilize the system in question. The proposal here is to replace traditional bulky LPTs with smaller fractionally rated units operating in parallel. Once the specification on these units is finalized, it is possible to maintain a reasonable spare inventory for identical units. The other motivation behind this has been to reduce the lost capacity for the same probability of failure. For example, if a 200 MVA transformer was replaced by three 67 MVA units, for the same probability of failure the lost capacity would be just 67 MVA. The approach is summarized in Figure 3.

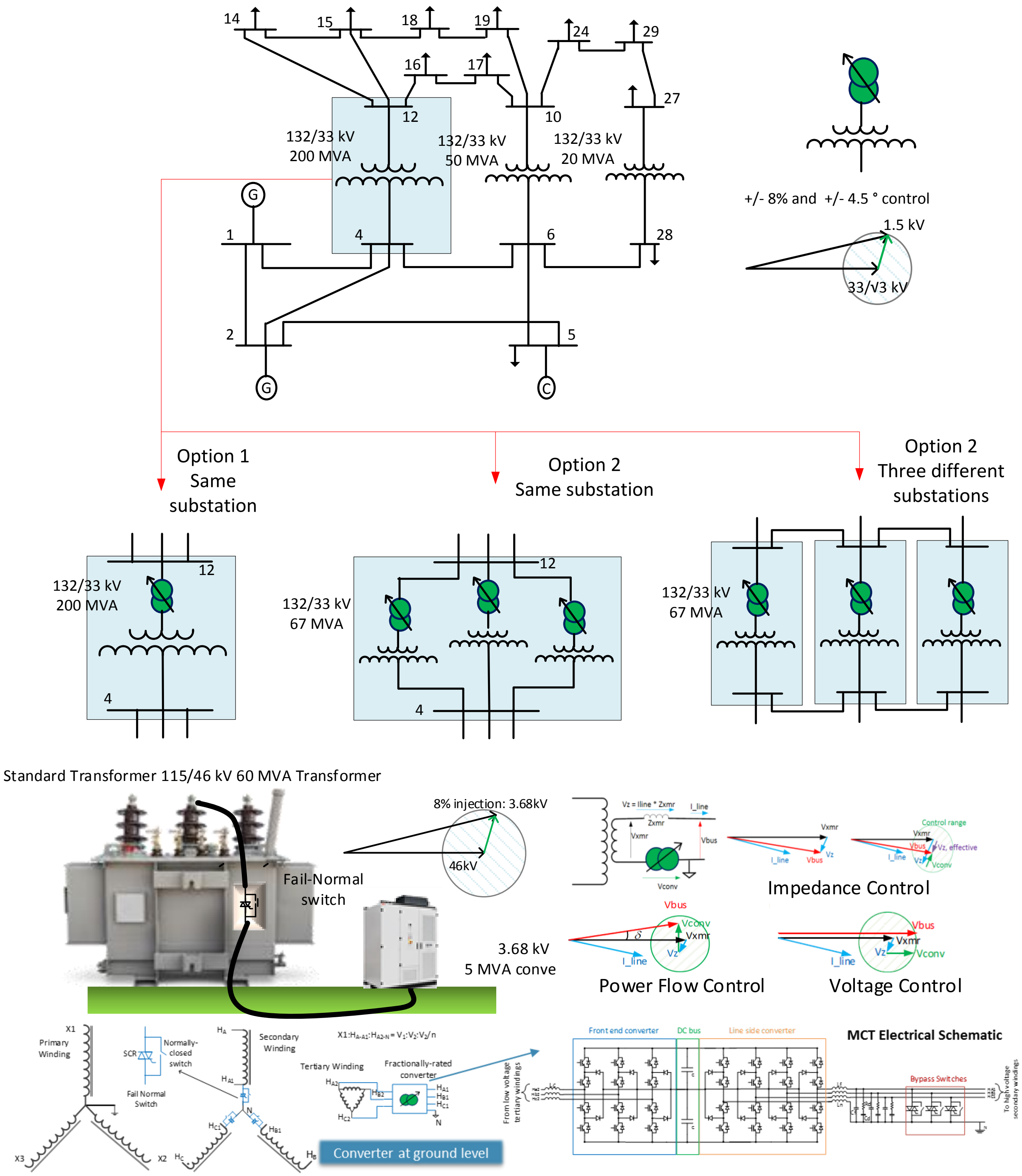


Figure3: MCT configurations

Three options for MCT placement were considered as shown in Figure 3. Some analysis has been conducted with regards to Option 2 to prove out the efficacy of the solution. The controllability aspect of the proposed approach is tackled by using a fractionally rated back-to-back converter to achieve various modes of operation. This converter would be placed on the low voltage tertiary winding of the retrofitted transformer. This would allow some degree of control over the impedance, power flow as well as voltage. In addition to this the control embedded will make the system more resilient in the face of contingencies.

Embedded Fail-Normal operation makes sure that the system operates as usual in case of converter failure. Impedance control ensures that these units can be paralleled with transformers of varying impedances making this unit retrofittable in numerous areas of the system without altering flows.

Details for the converter topology, transformer ratings, system impacts and cost analysis are presented in this report.

4.6 Converter Topology and Control

The topology consists of two back-to-back 3-level NPC inverters as highlighted in Figure 4.

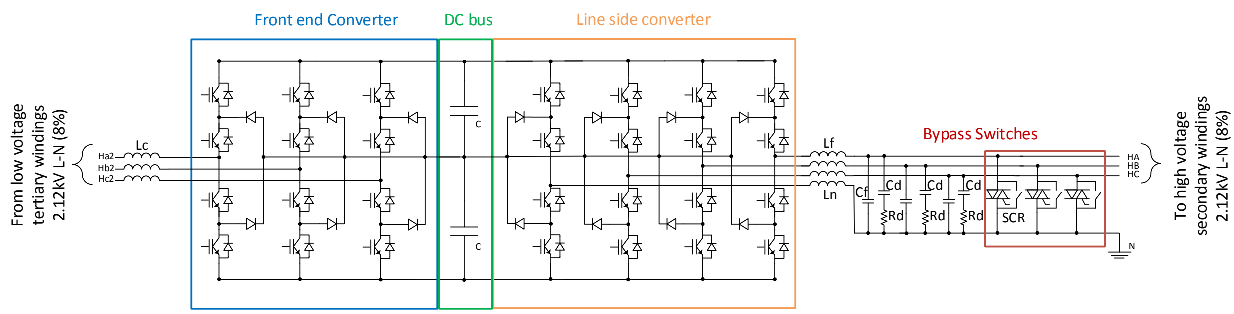


Figure 4: MCT topology

The leftmost 3-level NPC converter, hereafter referred to as the front end converter (FEC) is interfaced with the transformer low-voltage tertiary winding (2.12kV L-N – 8%) through a set of coupling inductors L_c. The rightmost 3-level NPC converter, refered to as the line side converter (LSC) in the following, is connected to the open neutral-end of the power transformer secondary winding through a LC filter and injects a controllable voltage (0-2.12kV RMS L-N, 0-360°, 8%) in series with the line voltage. The LSC makes use of a 4-th NPC leg to interface between the three phases and the neutral, therefore forming a four-wire system, and maintain a full controllability over the injected voltage even for an unbalanced loading of the line.

The objective of the FEC is to regulate the DC bus voltage while exchanging power with the tertiary winding at unitary power factor. It should be noted that the topology used is fully flexible and reactive power injection/sourcing is absolutely possible, if need be. The modulator for this converter is implemented using a classical 3-level Phase Disposition carrier-based PWM modulation scheme and uses the Centered Space Vector PWM method for zero sequence injection so as to maximize the DC bus injection and minimize the generated voltages harmonic content. Following the common practice for three-phase inverters, the control loops are implemented in the dq-power invariant synchronous frame, synchronized with the grid, so as to work with DC quantities.

The LSC is controlled to regulate the injected voltages irrespective of the line loading conditions. This is possible by utilizing the 4th leg on the topology which increases the number of available switching states. To make use of these additional switching states and work with DC quantities, the control loops are implemented in the dq0-power invariant synchronous frame, with an additional control loop on the zero axis. The PD-based modulator uses an adapted centered 3D Space Vector Modulation Scheme to once again maximize the DC bus utilization and improve the output voltage harmonic content through zero-sequence injection.

4.7 Converter simulation results

The preliminary converter design was validated through a detailed converter-level simulation implemented in Matlab/Simulink and Plexim/PLECS blockset.

The converter is simulated at the rated injection (2.12kV RMS LN) and the rated line current (786A RMS) corresponding to the rated converter power of $5MVA$ and a rated MCT unit power of 60MVA. The input tertiary winding voltage is also set to the nominal value of 2.12kV RNS LN. For this simulation, the line current is set to lag the line voltage by 40°.

The main results of this simulation are detailed in the following. The first quantities of interest are the DC bus total voltage and positive and negative pole voltages. As shown in Figure 5, after precharging the DC bus through a set of input resistors so as to limit the inrush current, the full MCT converter (FEC + LSC) is turned on. The total DC bus voltage is perfectly regulated to its reference value of 6kV DC, while the poles voltages reach a stable steady stable with a slight, yet perfectly acceptable, unbalance.

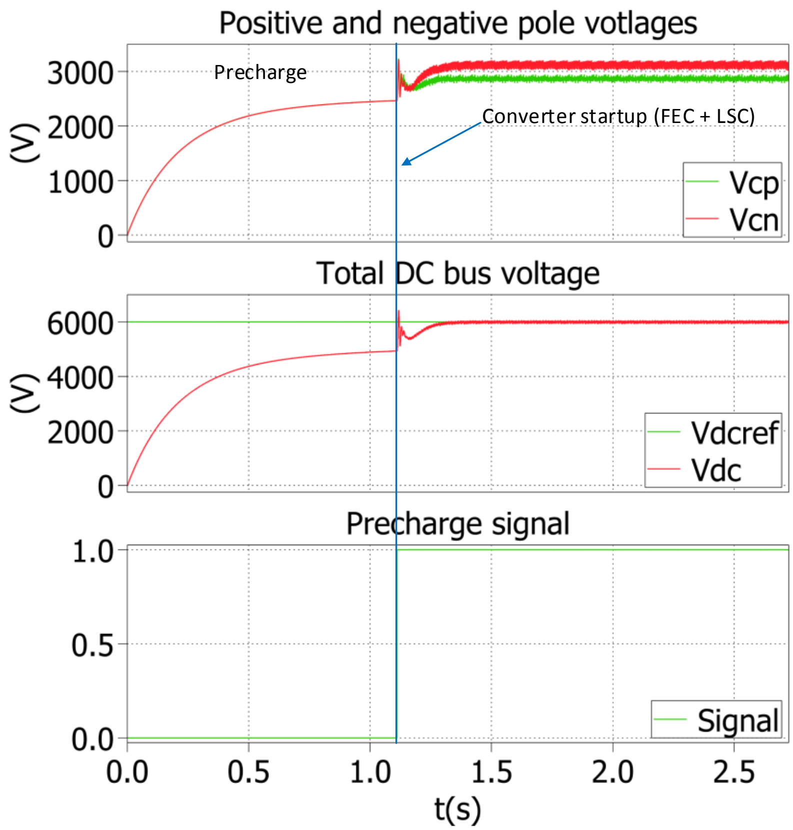


Figure 5: Converter DC bus waveforms

The resulting input voltages and currents, at the FEC input, are shown in Figure 6 and Figure 7.

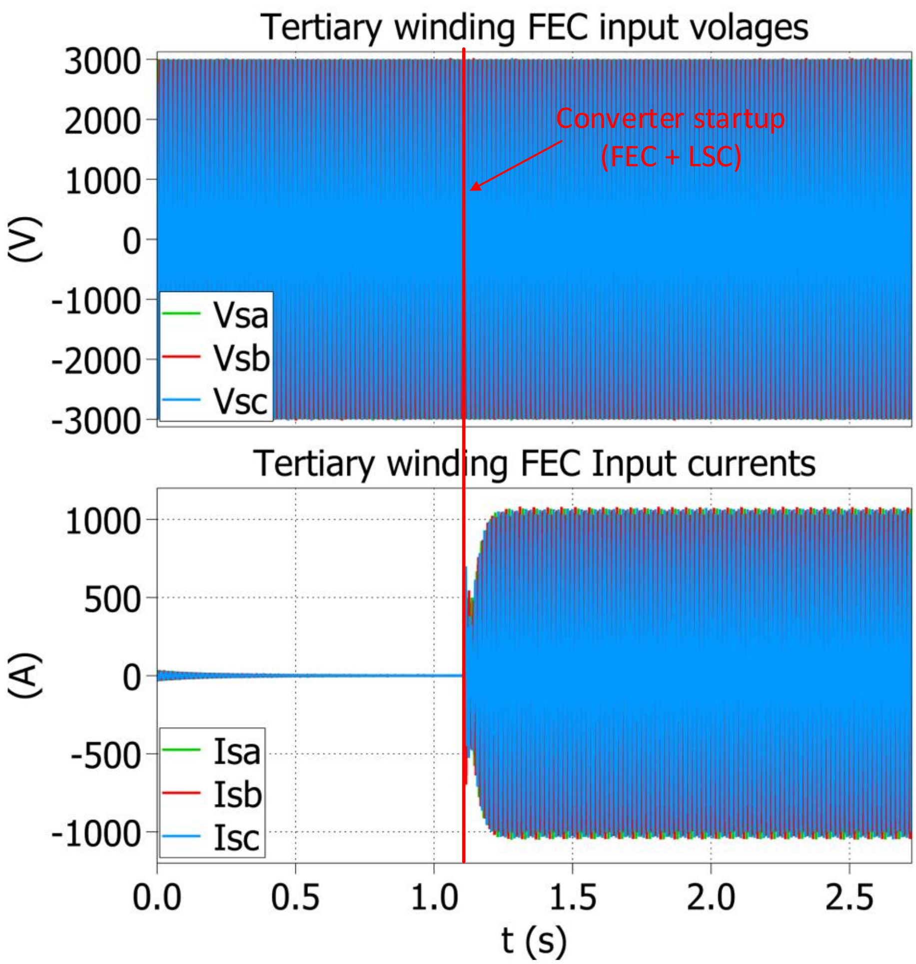


Figure 6: FEC input waveforms

After the precharge phase, the input current increases to its rated value to keep the DC bus at 6kV DC while the output converter (LSC) injects 2.12kV/5MVA to the line.

A more detailed view of the steady-state FEC input waveforms at 2.12kV/5MVA is given in Figure 7.

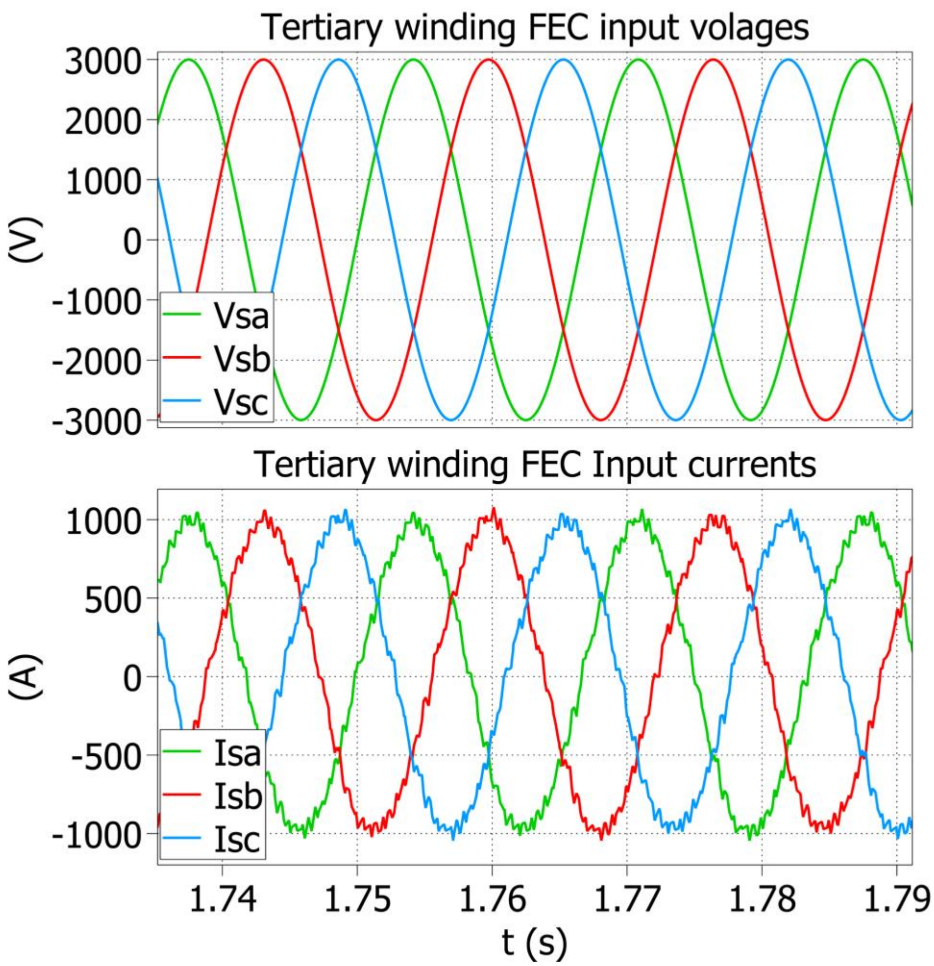


Figure 7: FEC steady-state input waveforms at 2.12kV/5MVA injection

The input currents are in phase with the input voltages, as per the design requirements, and current ripple is perfectly acceptable. This validates the preliminary design of the LSC. In light of this simulation results, further optimization of the coupling inductor value L_c is possible.

The next quantities of interest are the output converter (LSC) waveforms. Figure 8 shows the LSC output current, neutral leg current and injected line-to-neutral voltages.

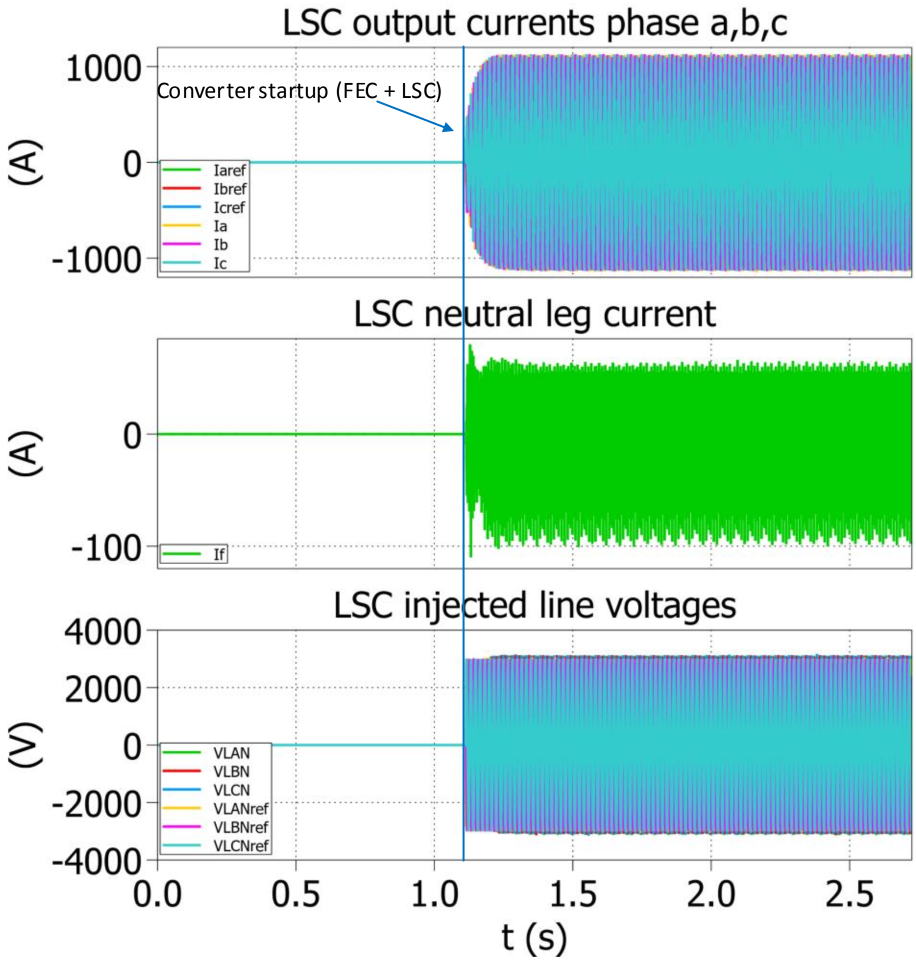


Figure 8: LSC output waveforms

As shown in Figure 8, as soon as the converter is started, the injected line voltages are quickly brought up to the nominal injection level of 2.12kV L-N RMS. The neutral leg current does not present any low frequency component as, in this simulation, the line current is perfectly balanced. A more detailed view of the converter waveforms during startup and in steady-state is given in Figure 9.

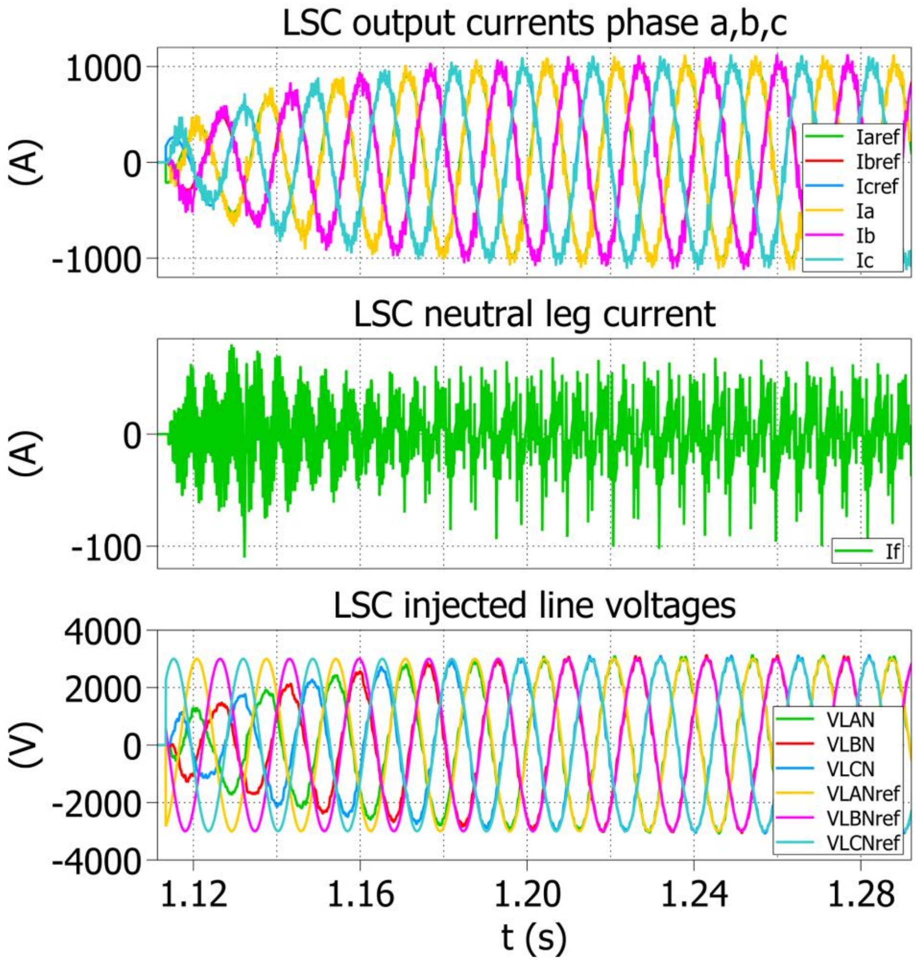


Figure 9: LSC startup and steady-state output waveforms at 2.12kV/5MVA injection

As shown in Figure 9, the LSC injected voltages quickly reaches the nominal reference values of 2.12kV LN RMS with a minimal and perfectly acceptable ripple. The neutral leg (4th leg) current does not have any low frequency component as expected as the line currents are perfectly balanced in this simulation. Finally, the injected leg currents also follow the reference values fixed by the control loops and once again the ripple is acceptable.

These results validate the preliminary LSC design, yet further optimization of the output filter is possible to minimize the components size and cost.

The complete converter operation (back-to-back FEC and LSC) is then stable under both balanced and unbalanced line conditions, with a full controllability over the injected line voltages while ensuring a unitary power factor power exchange at the FEC side. This validates the converter and control designs.

Details about specific component selection and target ratings are presented in the next section.

4.8 Converter Design Options

4.8.1 Target Voltage and Power Levels

The converter design would largely be influenced by voltage ratings as well as power level required to be handled. Based on inputs from our partner utility, two possible options for target transformers emerged in terms of the target ratings

Option 1: 115/46 kV units at 112 MVA

Option 2: 230/115 kV units at 400 MVA

Based on currently available IGBTs ratings, the maximum achievable voltage injection is detailed next. This analysis assumes a standard 3-level NPC topology as presented in the above without device stacking. It also assumes third harmonic injection that maximizes the DC bus utilization and gives a maximum line-to-neutral peak voltage of $\widehat{V_{inj}} = \frac{Vdc}{\sqrt{3}}$. Finally, a 40% margin on the DC bus voltage is applied with respect to the device voltage rating to account for DC bus ripple and switching overvoltages.

	Device	DC bus voltage	Maximum achievable injection (L-LRMS / % of line voltage)	Corresponding maximum converter power rating based on device rating	Corresponding maximum MCT unit power rating
Option 1	IGBT 6.5kV IXYS/Westcode	7.8 kV DC	5.5kV– 11.2%	6 MVA	53.5 MVA
Option 2	IGBT 6.5kV IXYS/Westcode	7.8 kV DC	5.5kV – 4.8%	6 MVA	125 MVA

Table 1: Option viability analysis

This demonstrates the scalability of the proposed solution that can readily achieve significant voltage injection including under the more challenging option 2. It would be possible to realize even higher voltage injection by considering other device technologies such as SiC-based devices or by stacking devices.

Owing to significant meshing on some 46kV sub grids operated by Southern Company, option 1 stands as an ideal first target and will be investigated in greater details in the rest of this report while option 2 will constitute a potential future development of the project. The target injection for option 1 will be equal to 8%, which corresponds to a required converter injection of 3.68kV RMS LL and a rated converter power of 4.5 MVA on a two MCT unit basis.

4.8.2 Commercial Counterparts and Housing Specifications under option 1

In order to understand the form factor and housing designs for the MCT units some readily available commercial counterparts were analyzed.

The proposed MCT topology is commercially available as medium voltage drives from ABB and GE Power conversion. Among the available converters, only the ones with a reversible input stage (usually commercialized under the name Active Front End) and with ratings close to the voltage and power range required under option 1 were selected. Furthermore, the DC bus of the selected two models are based on film capacitor technologies for reliability purposes and air-cooling was preferred when available. Some modification to the design will obviously be necessary (addition of a 4th leg to the output stage, adaptation of the power/voltage levels), the only objective of this section being to give a rough estimate of the size of the converter and to identify the manufacturers capable of building such converters.

GE power conversion

GE Power conversion offers a wide range of medium voltage motor drive under the MV7000 series. The MV7303 model is based on a 3-level 3-phase NPC VSI and reversible input stage using SI IGBTs and is rated for 3.3kV and 4.3MVA. A typical view of the drive is reported below (for a non-reversible input stage)

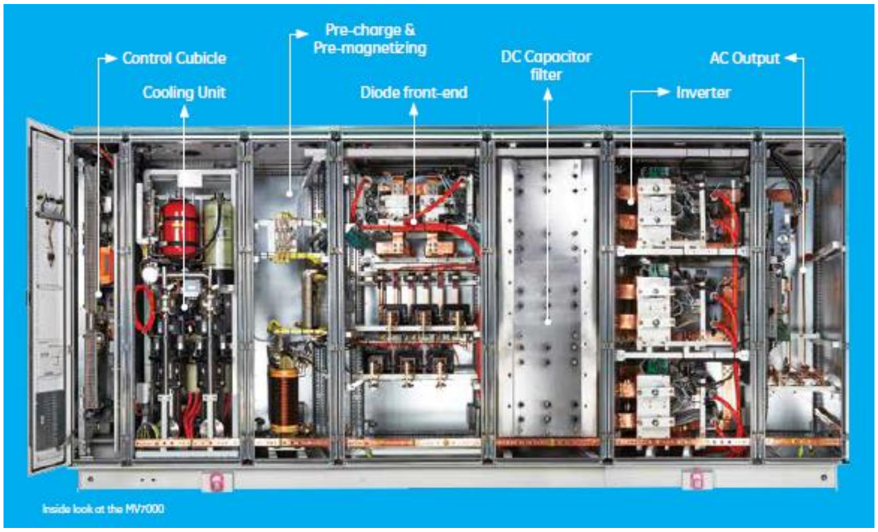


Figure 10: GE Power Conversion

The mechanical considerations of the MV7303 are as follow:

WxD(mm): 4800x1000

Weight: 4800 kg.

ABB

ABB has a large offering of motor drives and generators converters. The most promising candidates that is based on two back-to-back 3 levels NPC inverters is the PCS6000 series. This particular model is marketed as a medium voltage converter for wind turbines to grid interconnection but is offer in the voltage and power range required for the MCT application. The converters relies on IGCT devices while the DC bus is based on film self-healing capacitors. The cooling of the converter is water based. The 4MV/5MVA PCS6000 configuration is rated for 4.16kV/5MVA which meets perfectly the required ratings of option 1.

A typical view of the 5MVA PCS6000 is reported below:

Figure 11: ABB PCS6000

The mechanical specifications of the converter are as follow:

LxWxH (mm): 4560x1280x2460

Weight: 5100 kg.

From this short survey, it can be concluded that the target MCT converter unit is typically available with very little modification from two main MV converters and the footprint of such a converter would of about 5000x1000x2500 (LxWxH mm) for a weight of roughly 5000kg. With these requirements in mind, a final product requirement document for the converter was generated.

4.9 Converter Product Requirement Document

A Product requirement document was generated based on the findings and surveys for the converter unit.

4.9.1 Scope

These specifications describe a three phase, back to back converter topology designed to achieve power flow, voltage an impedance control. The unit will be connected on the tertiary winding of a power transformer and will inject a series voltage on the secondary. The input stage of the converter consists of a three-level neutral point clamped synchronous rectifier while the output stage involves a three level, four leg neutral point clamped converter.

4.9.2 System Description

Components

- 3 level NPC synchronous rectifier
- 3 level 4 leg NPC inverter
- Input filter
- Output filter
- Bypass through SCRs and NC relays
- Fuses
- DSP+FPGA control

System Operation

The following modes of operation will be followed

1. Bypass mode:

In this mode, the output stage is by-passed by shorting the secondary neutral terminal with the ground port. This way, the output stage is not adding any controlled voltage on the line. This mode will be useful for the pre-charging and synchronizing functions.

2. Active Injection mode

This mode highlights the main functionality of the MCT units. By adding a controlled voltage magnitude as well as phase shift in series with the secondary voltage, multiple objectives can be achieved. The three main functions are:

- Impedance control
- Voltage regulation
- Power flow control

3. Fail-normal mode

This mode is quite similar to the bypass mode in that it disconnects the output stage of the converter. However, this corresponds to any faulty mode of operation where the added control needs to be isolated to recover the basic transformer functionality

4.9.3 General Conditions for Installation

Required Input Capacity:

The converter unit will be rated at 4.5 MVA.

Grounding System:

The neutral of the four-wire system generated by the output stage will be solidly grounded.

Standard Environmental Parameters

The converter will be rated to operate in the same conditions as the transformer.

Operating Temperature	: up to 50^o C
Operating Humidity	: <95% non-condensing

System Parameters

1. General requirements

Rated Output Capacity	: 4.5 MVA
AC/DC rectifier type	: Three level NPC (synchronous)
DC/AC Inverter type	: Three level NPC (4 leg) inverter
External dimensions	: 4560x1280x2460 (LxWxH mm) from ABB PCS6000 5MVA in-line-config (or equivalent)
Weight	: 5100kg
Max Surge Voltage	: 5.06 kV

2. AC Input

Configuration	: 3 phase wye or delta
Rated Voltage	: 3.7 kV (line-line)
Rated Frequency	: 60 Hz
Frequency Variation	: +/- 2.5 %
Input Power Factor	: Greater than 0.99 lagging at 100% load
Current THD	: <5% at 100% load

<10% at 25% load

3. Pre-charging

DC Nominal Voltage	: 6 kV
AC Ripple on DC bus	: 10% of DC voltage
DC voltage range	: 5.25-7Kv

4. Bypass

Rated output voltage	: 3.7 kV (line-line)
Rated Frequency	: 60 Hz

5. AC Output

Configuration	: 3-phase/4-wire
Rated Capacity	: 4.5 MVA overloading?
Rated Voltage	: 3.7 kV (line-line)
Efficiency	: >95%
Voltage injection range	: 0-3.7kV
Harmonic voltage distortion	: <5% (balanced load)
	<10% (unbalanced load)

<u>Functional Description</u>

1. Input Bridge (Synchronous Rectifier)
   The input stage regulates the DC bus voltage. The power is drawn at a unity power factor.

   Voltage Regulation

Nominal DC Bus Voltage	: 6kV
Voltage Variation	: +/- 10%
Frequency Change	: +/- 2.5%

2. Output stage

   The output stage topology is a three level four-leg NPC converter. Each leg consists of 4 IGBTs, 2 clamping diodes and 4 anti-parallel diodes. Converts DC-AC while controlling the phase and magnitude of injected output voltage

   - Synchronization:

     The inverter output voltage shall be automatically synchronized with the grid as long as the grid is within the tolerable frequency and voltage range.

- Output Control:

  Slow set point control through communication protocols

- Overload Capacity:

  The converter unit will be designed to match the overload capacity rating of the transformer unit.

Metering and Monitoring

The following states shall be monitored:

- AC input voltage/current
- AC output voltage/current
- Loss of synchronism
- Diagnostics of each converter
- Output frequency
- DC bus voltage
- Temperature
- Commutation faults

4.10 Final converter design and component selection.

Following the target injection (8% - 2.12kV L-N) and target MCT unit power (60MVA), the converter target rating are as follows:

- Converter input/output rated voltage: 2.12kV RMS L-N
- Converter rated power: 5MVA (corresponds to 786A RMS)

One of the critical component, and limiting factor, of any power converter is the power semiconductors used. Based on the rating of the high power IGBTs with integrated antiparallel diode readily available from the main power semiconductors manufacturers and the target injection level, the DC bus voltage has been set to 6kV DC and two IGBTs from IXYS/Westcode and ABB have been selected. The characteristics of these two IGBTs are reported in the Table 2.

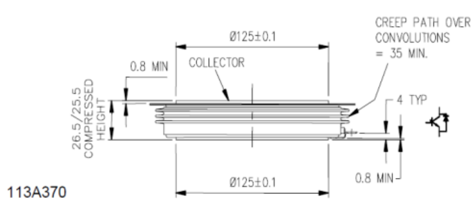
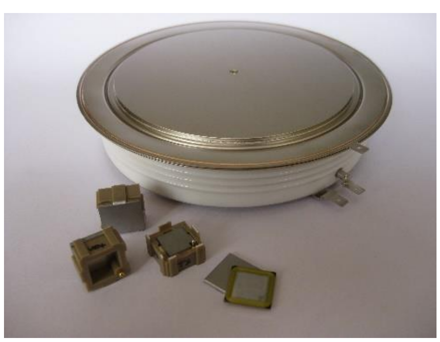
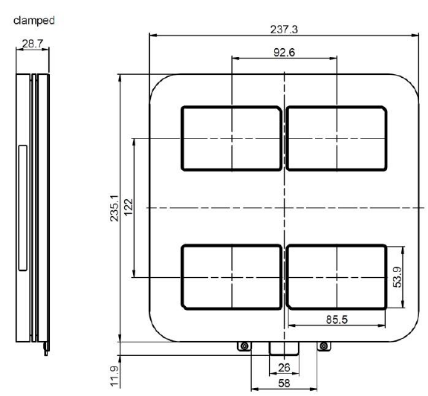
	IXYS/Westcode T1600GB45G	**ABB 5SNA 1300K450300**
VCE	4500V	4500V
IC	1600A	1300A
Estimated total losses at fsw=1kHz	8kW	7kW
Packaging	Press Pack IGBT  	StakPak IGBT  

Table 2: Commercially-available IGBT with integrated diode from ABB and IXYS/Westcode meeting the application target ratings

The switching frequency (frequency of the carriers) is set to $f_{sw} = 1kHz$ to keep the losses in the semiconductors to an acceptable level while maximizing the converter bandwidth and facilitating the filter design.

Subsequently the input coupling inductor is set to $L_c = 2.1mH$ while the output filter LC cell is set to $L_f = 1.1mH$ and $C_f = 147\mu F$. The damping of the LC cell is achieve through a RC structure as shown in Figure with $R_d = 4.4\Omega$ and $C_d = 270\mu F$.

This preliminary filter design provides enough harmonic attenuation on the output voltage injection and is feasible based on the current L and C technologies available.

The main primary converter design elements are summarized in the table below (Table 3):

Quantity	**Value**
$\boldsymbol{V_{dc}}$	6kV DC
$\boldsymbol{f_{sw}}$	1 kHz
$\boldsymbol{L_C}$	2.1 mH
$\boldsymbol{L_f}$	1.1 mH
$\boldsymbol{C_f}$	147 μF
$\boldsymbol{R_d}$	4.4 Ω
$\boldsymbol{C_d}$	270 μF
$\boldsymbol{C_{bus}}$	4.8 mF

Table 3: Primary converter design element

4.11 Transformer design options

The modular transformer unit that will be augmented with this converter is an extremely crucial piece for equipment for this approach to work. Multiple design options for transformer design were explored. The objective was reducing commissioning time as well as transportation time with this design. With this in mind one of these options is finalized so as to reduce the time for filling oil and transportation at a minimum.

In this section, the preliminary transformer design options under review will be presented.

Four preliminary transformer designs have been proposed by Delta Star following the application-level requirements identified by the Georgia Tech team. These designs are based on a variety of power levels and cooling strategies as follows:

- Option 1: Single three phase unit rated 67/90/112 MVA, ONAN/ONAF/ONAF, 65˚C
- Option 2 - Three phase 60 MVA, ODAF 95˚C mobile (2 units to replace single 112 MVA) on trailer
- Option 3 – As option 2 but portable unit without trailer
- Option 4 –Two three phase units 34/45/56 MVA, ONAN/ONAF/ONAF, 65˚C to be paralleled and replace single three phase 112 MVA unit from option 1.

The transformers connections for all four options are as follows:

HV 115 kV Delta, BIL 450 kV

LV 46/26.56 kV Grd Y, BIL Line 250 kV, N 110 kV, standard 30˚ shift

HV-LV impedance voltage 9% based on ONAN rating and 15% based on ODAF rating (options 2 and 3)

All ends of LV windings will be brought out through the bushings (to be connected to the line and to the neutral through the Fail Normal Switch of the converter)

Tertiary winding voltage of 3.91 kV (8.5% of LV line voltage) Delta connected with bushings connected to the externally mounted MCT converter.

The preliminary design data for the four options are reported below (Table 4, Table 5 and Table6)

Option	MVA	Temp Rise (˚C)	No load loss (kW)	Load loss (kW)	Total loss (kW)	Impedance (%)
1	67 ONAN	65	47	137	184	9
1	112 ONAF	65	47	393	440	15
2 and 3	60 ODAF	95	21	605	626	15
4	34 ONAN	65	29	94	123	9
4	56 ONAF	65	29	269	298	15

Table 4: Transfomer design options losses and impeance

Temp Rise – Winding temperature rise over ambient. The oil temperature rise is 65˚C at all options

Impedance – Impedance voltage at stated MVA rating

<u>Weights</u> (in lbs.)

Option	C+C	T+F	Oil	Total	Ship w/oil	Ship w/o oil
1	121,600	50,100	58,800	230,500	214,000	155,200
2	48,000	32,200	30,000	110,200	99,800	69,800
4	72,200	37,500	41,100	150,800	140,400	99,300

Table 5: Transformer design option wieghts

C+C – Core and coils

T+F – Tank and fittings

<u>Tank dimensions</u> (in inches)

Option	Length	Width	Height
1	169	78	159
2	123	63	135
4	150	72	139

Table 6: Transfomer design options dimensions

4.12 Transformer final design

In this section, the transformer design is presented.

Based on the four preliminary transformer designs proposed by Delta Star and presented in the last quarterly report, option 4 has been selected. This design consists of two three-phase units 56 MVA, ONAF, 65˚C to be paralleled and replace a single three phase 112 MVA unit. The transformers connections are as follows:

HV 115 kV Delta, BIL 450 kV

LV 46/26.56 kV Grd Y, BIL Line 250 kV, N 110 kV, standard 30˚ shift

HV-LV impedance voltage 9% based on ONAN

All ends of LV windings will be brought out through the bushings (to be connected to the line and to the neutral through the Fail Normal Switch of the converter)

Tertiary winding voltage of 3.91 kV (8.5% of LV line voltage) Delta connected with bushings connected to the externally mounted MCT converter.

The design data are reported below (Table 7, Table 8 and Table9)

Option	MVA	Temp Rise (˚C)	No load loss (kW)	Load loss (kW)	Total loss (kW)	Impedance (%)
4	56 ONAF	65	29	269	298	15

Table 7: Transfomer design losses and impedance

Temp Rise – Winding temperature rise over ambient. The oil temperature rise is 65˚C at all options

Impedance – Impedance voltage at stated MVA rating

<u>Weights</u> (in lbs.)

Option	C+C	T+F	Oil	Total	Ship w/oil	Ship w/o oil
4	72,200	37,500	41,100	150,800	140,400	99,300

Table 8: Transformer design wieghts

C+C – Core and coils

T+F – Tank and fittings

<u>Tank dimensions</u> (in inches)

Option	Length	Width	Height
4	150	72	139

Table 9: Transfomer design options dimensions

4.13 Transformer Product Requirement Document

The Product Requirement Document (PRD) was developed with inputs from Delta Star for the transformer unit. The specifications for the converter unit were developed through internal discussions at CDE – Georgia Tech. A preliminary design for a 67MVA unit was developed by Delta Star. After further conversations with Southern Company it was concluded that the target transformer unit rating would be 115/46 kV. The MCT approach would aim to replace these large units with two 66 MVA units.

4.13.1 Scope

- This specification defines an oil-filled power transformer. The specification defines equipment that is required unless specifically stated otherwise in the fill-in data section at the end of this specification. Also, equipment or performance characteristics which are indicated in fill-in data section shall be deemed as required. The six LV wye connected windings leads will be brought out through the bushings. The neutral side of the windings will be connected through the three of the bushings to the bypass switches of the converter. The delta connected tertiary winding leads will be brought out through the bushings and connected to the converter.

4.13.2 Use of Equivalents

- When equivalent equipment to the specified equipment is allowed, the transformer manufacturer shall provide documentation regarding the design and operation of the proposed equivalent equipment with the approval drawings to enable the end user to determine the suitability of the substitute.

4.13.3 Codes and Standards

- The transformer furnished under this specification shall be designed in compliance with the latest published standards of ANSI, IEEE, NEMA, NEC, NESC, and ASTM where applicable and unless otherwise noted. If any of the requirements of this specification are in conflict with these standards the Manufacturer shall notify the Customer.

4.13.4 General Ratings

- The transformer shall be subjected to the standard conditions defined by IEEE C57.12.00 Section 4, Service Conditions where it is applicable, unless otherwise specified
- The transformer and all components shall be designed to withstand the forces associated with a 100-mph wind velocity
- All ancillary devices; including all load tap changers, de-energized tap changers, leads, and bushings shall be sized so that the design of the windings and cooling shall be the limitation to overload.

4.13.5 Transformer Nameplate Ratings

- The transformer shall be three phase, oil filled and outdoor-type with ODAF cooling system. The transformer will be guaranteed not to exceed the average winding and top oil temperature rise when operated in a 30° C, 24-hour average ambient temperature. The substation shall be operable in a 40° C maximum ambient temperature.

4.13.6 Core Construction

- The core is circular, built with high grade, grain orientated silicon steel laminations and provided with insulating step blocks filling the gap between the flat frame and the curved shape of the core top and bottom yokes to ensure that the core is adequately clamped and supported.
- The top and bottom yokes and legs shall be of single sheets of steel that run the full length of the leg or yolk to minimize the number of joints in the core and to reduce core-loosening of the lifetime of the transformer. Scrap-less, mitered cores shall not be allowed. Step-lap core design is preferred.
- The transformer will be designed to continuously accommodate 110% excitation voltage without load per IEEE standards listed.
- The core will be supported by step-blocks of high-density insulation to support the core laminations and distribute the top and bottom frame pressure.
- High density EHV Weidmann, Rochling or approved equal insulation shall be employed between the core and the end frames to reduce creep of the insulation over time and loosen the core clamping.
- Bolts passing through the core laminations will not be allowed.
- The location where the core ground strap enters the core shall be visible from the manhole cover. The core ground shall be brought out through a 1.2 kV (30 kV BIL rated) bushing labeled "core ground" and protected by a steel guard or enclosure to protect it from being stepped on. The bushing will be connected to a NEMA ground pad welded within one foot of the bushing.

4.13.7 Coil Construction

Insulation Levels of the Transformer Coils

- 230 kV Class – 650 or 750 kV BIL (Bushings will be rated for 900 kV BIL)
- 161 kV Class – 650 or 750 kV BIL (Bushings will be rated for 750 kV BIL)
- 138 kV Class – 550 or 650 kV BIL (Bushings will be rated for 650 kV BIL)
- 115 kV Class – 450 or 550 kV BIL (Bushings will be rated for 550 kV BIL)
- 69 kV Class - 350 kV BIL
- 46 kV Class - 250 kV BIL
- 35 kV Class - 200 kV BIL
- 25 kV Class - 150 kV BIL
- 15 kV Class - 110 kV BIL
- 5 kV Class - 75 kV BIL

Insulation System

- The manufacturer shall be able to demonstrate the design of insulation system employed through finite element methods. An acceptable demonstration would be the availability of static voltage plots for the voltage class being offered. For higher than 65˚C temperature rise design, IEEE C57.154 standard should be followed.
- The winding tube shall be EHV Weidmann or approved equal. Manufacturer will state the origin and winding tube material in their proposal.

Coil Construction

- The coils will be of circular design, disc or helical type wound, pre-sized, clamped and braced to provide adequate short circuit strength.
- Vertical clamping force shall be uniformly applied of the entire horizontal surface of one-piece pressure plate. Only one-piece upper and lower pressure plates shall be allowed to ensure positioning is maintained. No slots will be allowed in the pressure plate.
- The inter-disk spacers shall slide on keys firmly attached to each winding tube.

Short-Circuit Strength Verification

- The ability of the core and coil superstructure and clamping assembly to withstand short circuit forces as required by IEEE will be verified on transformer design(s) of the same construction through short-circuit testing with test results provided upon request.
- Calculations of leakage flux at all positions in the transformer windings shall be made by finite-element or equivalently thorough methods to determine the short-circuit forces and temperatures present at each turn of the transformer windings of the individual design.
- An infinite bus capacity will be assumed in all short-circuit current and force calculations. That is, the transformer shall be designed to be protected by the impedance internal to the transformer alone.

Impedance

- The impedance will be as specified or manufacturer's standard.

4.13.8 Processing

- Upon placement of the coils on the core, the method of final sizing of the coils shall be by hydraulic press only and shall not utilize the method of retaining the coil preload stress as the means for sizing. Utilizing a method of sizing other than by hydraulic press shall only be allowed if the manufacturer can demonstrate that shavings are not generated and that the final preload stress can be determined.
- Manufacturer shall state the calculated pre-loading stress of the coils.

- Manufacturer shall state method of drying coils. Preferred method is the vapor phase system. The manufacturer shall state in his proposal the minimum insulation power factor and partial discharge levels at final testing that will be guaranteed.

4.13.9 Internal Connections

- All connections of windings to leads shall be made by brazing or a full-circumference crimp connection to for a tight bond with the conductor.
- All leads shall be rigidly clamped within a lead support structure that fully supports the weight of the leads and the forces exerted on them during a short-circuit condition.
- Leads shall not be attached to the inter-phase barriers.
- Lead support structures shall be attached to end-frames on supports welded to end frames. No studs shall be shot on the end-frames without fully welding around their perimeter.
- No ties made of nylon or other plastic materials shall be used.
- Fiber bolts shall be epoxy-locked or use two nuts on each bolt to insure against loosening.
- Lead support structures and insulation shall be connected by non-conducting fiber bolts. No black iron shall be used.

4.13.10 Internal Frames and Bracing

- The core and coil assembly shall be positively located at the bottom of the tank during the tanking process.
- The core and coil assembly shall be braced against the top frames against the tank walls at four locations and against movement in both horizontal directions.
- The bracing scheme shall not employ welding inside the tank once the core and coils are placed inside the tank.
- FOR SKID-MOUNTED APPLICATIONS: Metal-metal frictional bracing will not be allowed which could generate metal particles during movement.
- Slotted bolt holes shall not be employed that could allow for travel if the bolts were to loosen.

4.13.11 Tank

- The tank shall be made of steel and not aluminum.
- The tank is designed for pressures 25% greater than the maximum operating pressure and to withstand full vacuum. (+/- 15 PSI)
- Tank is reinforced with fully enclosed sidewall braces, with all seams and joints continuously welded on flat surfaces.
- Where possible, tank corners shall be rounded and seamless and tank wall welds will be a minimum of six (6) inches from the start of the corner bend. Tank seam welds shall fully penetrate to the inside of the tank.
- The tank shall be tested to guarantee free from oil leaks.

- The tank cover and tank external features shall be designed to prevent water collection. Doming the cover by flexing and welding it to the main tank or other means that pre-stress the tank cover shall not be allowed.
- Only stainless steel studs shall be used on the tank and studs shall be completely welded around the perimeter of their base.
- All mounting bosses shall be welded on the inside of the tank as well as on the outside to prevent creation of hiding location for foreign debris.
- All bolted hardware shall be stainless steel, silicon-bronze or brass.

4.13.12 Cooling System (ODAF)

- The fan and pump motors are to be designed for operation on a 208-240 volt, three phase 60-cycle source. The pump motors shall not require maintenance.
- The three phase fan motors shall have an arrow indicating the correct rotation affixed to each of the fan shrouds.
- The coolers shall be of the seamless tubing type, having fins on the outside to increase the transfer of heat to the cooling air.
- The cooling system shall consist of at least two independent systems capable of providing adequate cooling to operate the transformer at the minimum of 70% loading indefinitely with no adverse or abnormal effects if one system should fail.
- . The supplier shall provide the flow rate of the pumps with the bid. Care will be taken to reduce the oil velocity such as to reduce the likelihood of static electrification.
- A vane-operated oil flow indicator is to be located in the path of oil flow for each of the independent systems. They shall be designed to indicate when correct rate and direction of oil flow is attained. In addition, if the fan motors are three phase, an arrow indicating the correct rotation shall be affixed to each of the fan shrouds.
- Trip contacts will be provided to signal need for load removal in the event of loss of entire cooling system. An alarm condition will occur with loss of one cooling unit.
- Fan guards are to be stainless steel or hot dipped galvanized and shall meet all OSHA requirements including a ½" diameter rod not penetrating the guards.

4.13.13 Oil Preservation System

Sealed Tank (Standard)

- The transformer is provided with a sealed tank design where space above the oil is purged and filled with dry nitrogen. A pressure/vacuum gauge will be provided. A pressure/vacuum bleeder will be provided to automatically relieve positive or negative pressure differentials greater than 6.5 PSI.

Nitrogen-Regulated (if specified in fill-in data sheet attached)

- If an automatic nitrogen pressure system is specified, the tank is provided with all necessary devices enclosed in a weatherproof cabinet. The height of the cabinet is positioned so that the nitrogen cylinder is not lifted more than 8 inches. The nitrogen inlet line and the gas space sampling line are positioned at opposite ends of tank or cover. This allows for correctly measuring the oxygen content while simultaneously filling the gas space with nitrogen.

- The nitrogen-regulated preservation system will automatically maintain the nitrogen blanket pressure in the gas space to a level between 0.5 and 6.5 positive PSI. If the pressure drops below 0.5 positive PSI a two stage regulator system will pass nitrogen from the nitrogen cylinder housed with the regulator in a NEMA 4 enclosure on the tank wall to the gas space. Should the gas pressure exceed +6.5 PSI the nitrogen will be bled-off. Separate form "C" contacts will be provided to signal a high pressure, low pressure or empty cylinder condition.
- The nitrogen cylinder shall be rigidly mounted inside the NEMA 4 enclosure. The means of securing the cylinder shall be a metal band that does not allow the cylinder to shift.

4.13.14 Bushings

- Bushings with insulation level of 200 kV BIL and above shall be porcelain (or customer approved equal) oil-filled condenser type with a power factor test tap.
- Bushings with insulation level of 150 kV BIL and below will be porcelain or epoxy without power factor taps and will be stud (bottom) connected.
- Bushing color to be ANSI 70 light gray
- Bushing connectors will be Anderson Type HDSF or equivalent compression connectors

4.13.15 Off-Load (De-Energized) Tap Changer and Voltage Switches

- The high voltage is provided with a no-load de-energized tap changer with full capacity taps at 5% and 2.5% below and above rated voltage.
- Operation of the tap changer or switches shall not require entry to the transformer tank.
- The tap changer or switch shall be lockable with a common padlock in any position.
- The tap changer or switch handle shall employ a pin that must be withdrawn prior to the handle being turned. The handle shall not freely turn without a padlock in place as a safety measure.
- The tap changer or switch contacts shall be designed to firmly seat in position. Seating of the tap changer or switch shall be discernable from the operating handle.
- The tap changer or switch shall seat such that no mechanism outside the transformer tank shall be required to position or seat the tap changer.

4.13.16 On-Load (Energized) Tap Changer (N/A)

- When specified, a load tap changer in the low voltage side provides voltage regulation of ±10% variation in 16 equal steps both above and below rated voltage. Per ANSI standards, the transformer will be capable of supplying rated kVA for all steps above nominal and current equal to rated kVA at nominal kV for all steps below nominal.

- The load tap changer shall be designed to supply 500,000 operations regardless of which tap positions those tap changes may occur at. The supplier shall state how many operations each individual LTC tap position is capable of performing.
- The LTC mechanism dielectric oil shall be separate from that of the main transformer. The tap changer shall be external of the transformer tank for ease of maintenance.
- No component of the tap changer motor drive or control compartment shall be located more than six feet from the ground.
- The tap changer shall be capable of being fitted with a remote position indication system in the field without de-energizing the transformer.
- A digital voltage-regulating relay will be provided which will automatically control tap changer based on a 120-volt feedback source supplied with the mobile substation.
- Line drop compensation current transformer and controls will be provided. The line reactance and resistance will be digitally programmed into the voltage-regulating relay.
- If specified, the controls are provided with all necessary devices for separate or future parallel operation with another transformer.

4.13.17 Oil

- The transformer will be shipped with new inhibited oil, certified to be less that 1PPM of PCB's.
- All oil characteristics shall be according to the latest ASTM/IEEE performance levels.
- Manufacturer shall specify make and trade name of transformer oil for purpose of future dissolved gas analysis assessment.

4.13.18 Gaskets

- All manhole openings, bushing bosses or risers and other areas where bolting is necessary will be provided with machined-surfaces with a gasket groove to limit compression of the gasket material.
- All gasket material shall be reusable nitrile material.

4.13.19 Transformer Gauges and Fittings

Standard Accessories

- All contacts to be of Form "C" (three wire: a N.C. and N.O contact and a shared common)
- Magnetic liquid level gauge with one low level alarm contact and one critical level trip contact
- Dial type liquid temperature indicator with three adjustable sets of contacts
- Winding temperature indicator with three adjustable sets of contacts
- Pressure vacuum gauge and bleeder if not fitted with regulated nitrogen pressurization system.
- Combination 2-inch drain/filter/sample valve and a 1-inch upper filter valve

- Two ground pads, on diagonally opposite corners of the tank plus a ground pad for each neutral bushing provided
- Stainless steel nameplate with etched (not painted) surface
- Pressure relief device with one set of contacts

Optional Accessories

- Sudden pressure relay with seal-in-relay mounted in gas space as standard

4.13.20 Surge Arresters and Mounting Provisions

- Surge arresters will be station class unless otherwise specified. Rigid jumpers will be supplied to short out the bottom arrester in dual voltage applications.
- Surge arrester supports will be designed for 100 mph wind loading.

4.13.21 Current Transformers

- Current transformers compliant with ANSI C57.13 will be provided. CT secondary wiring is 12 AWG, contains no splices and is terminated to shorting blocks with ring type compression connectors using properly sized ratchet type tools.
- Each current transformer will be wired to a dedicated six or twelve-point shorting block in the control cabinet.
- The manufacturer of the current transformer will be specified in the proposal.

4.13.22 Grounding

- Each lightning arrester shall be connected to ground system with a 4/0 AWG cable.
- A copper-faced NEMA-standard size ground pad shall be located in two diagonally opposite corners at the base of the transformer.
- The transformer shall be supplied with copper bolts and locking hardware in each hole of the supplied ground pads.

4.13.23 Controls Section

- Control cabinets shall be mounted to be accessible when standing at the side of the transformer.
- The cabinets shall have NEMA 4 classification with cable or conduit entries on the side of the cabinet, doors with non-corrosive hinges, padlock facilities, pocket for drawings and a removable plate in the bottom for customer incoming wiring.
- All devices and terminal blocks are clearly labeled and correspond to the wiring drawings.
- Adequate space around the terminal blocks is provided to allow for the installation and terminate of incoming wiring.
- A 12” high by 20” wide space shall be reserved for future mounting of equipment in existing cabinets or separate SCADA box.

- Control cabinet heaters (heat shield and ventilation fan shall be employed for hot climates)
- Control cabinet lights with door operated switch
- Control cabinet-mounted GFCI power outlet

4.13.24 Wiring

- All external wiring will be run in ridged conduit or liquid-tight flexible metallic conduit.
- Type SO or SOW cords and quick disconnects will be allowed on devices and gauges and in areas where physical damage would not occur.
- Wiring will be NEC type SIS 600 volt in the control cabinet and acceptable wire types in conduit will be THHN, THXW, MTW or SIS type wire.
- All devices are identified with permanently attached labels that correspond to the wiring drawings provided.
- Control circuit wire size is not less than 14 AWG except when wiring to customer-specified devices that will not accept wires this large. In this case the largest wire size that will fit will be used.
- CT secondary wiring is 12 AWG and power circuit wiring is sized and protected for the current required.
- Wire identification shall be provided on each end of all wires.

4.13.25 Paint

- The internal surface of the tank and underside of cover is shot blasted and painted white, minimum dry film thickness to be 2 mils.
- The transformer paint system shall comply with ANSI C57.12.28 transformer paint standard requirement that the entire tank be shot blasted as a single unit. The manufacturer shall be aware of the time limit to prime a unit following shot-blasting and make this available upon request.
- The paint system will use a two-part epoxy primer and a polyurethane enamel top coat for the most durable finish possible. The minimum build at any point will be 5 mils.
- The manufacturer shall provide documentation where the paint system has passed a salt spray test of at least 1000 hours with the minimum thickness applied to the transformer
- The final color shall be ANSI 70 Gray
- Both the primer and the topcoat shall employ corrosion protection such that only the air-dry topcoat need be applied as touch-up paint in the field.
- Touch up paint to be provided, one spray can of primer and one spray can of finish paint.
- Tank cover paint shall have sand added to it to form a non-skid texture.

4.13.26 Nameplates

- All nameplates will be stainless steel and mounted in an external conspicuous location using stainless mounting hardware. No adhesives will be allowed.

4.13.27 Submittals

Information supplied with proposal

- Fully-dimensioned outline drawings
- Recommended spare parts list
- Data requested in this specification to sufficiently illustrate in detail the equipment to be shipped.
- Proposed Engineering/Manufacturing/Shipping/Field Assembly schedule in the format that will be used to convey this information on a regular basis after award is made.

Information to be supplied at time of engineering approval

- Fully-dimensioned outline drawings
- All purchased component drawings
- Control wiring drawings
- All auxiliary equipment such as valves, pumps, fans, gauges, relays, etc., must be identified on drawings as to manufacturer, type, catalog number and quantity installed

Information to be supplied at time of shipment in the form of 1 bound copy to be delivered with the transformer and 1 CD-ROM copy

- Outline showing all auxiliary equipment such as valves, pumps, fans, gauges, relays, etc., must be identified on drawings as to manufacturer, type, catalog number and quantity installed
- Nameplate drawing
- Control wiring drawings
- Bushing CT excitation curves
- Bushing CT accuracy curves
- Renewal parts list
- Copies of the test report, including impulse waveforms, will be provided and included with on CD-ROM instruction manuals.
- Instruction and Maintenance Manuals will be provided containing the outline, nameplate and control wiring drawings, transformer test reports, catalog cut sheets of bushings and all devices, exciting current curves for CT's provided and recommended maintenance procedures.
- All files to be either .PDF (Adobe Acrobat), .DWG (Autodesk AutoCAD), or as specified.

4.13.28 Tests

Routine tests performed in accordance with ANSI C57.12.90 or as specified:

- Oil dielectric test (ASTM D877/D1816)
- Resistance measurements of all windings at rated and extreme tap positions

- Ratio test at rated voltage and all taps.
- Polarity and phase relation tests
- No-load loss and exciting current at rated and 110% voltage
- Load loss at base rating, rated voltage taps and at tap extremes
- Positive sequence impedance at base rating, rated voltage taps and at tap extremes
- Impulse for ANSI Class II power transformers
- Manufacturer shall state format which waveforms are recorded and stored.
- Applied potential test
- Induced potential test shall be per ANSI standard for ANSI Class II transformers or as applicable
- Winding insulation resistance
- Core insulation resistance (tested at > 1 kV)
- Insulation power factor (expected not to exceed 0.35% corrected to 20° C for power transformers)
- Polarity and ratio of all CT's on all taps after final complete factory wiring.
- Pressure test of transformer tank shall be performed for a minimum of six hours.
- Partial Discharge test and RIV test shall be performed simultaneously on all windings. No partial discharge greater than 300 pico-coulombs or 100 micro-volts shall be acceptable.
- Impulse (ANSI specified) with voltage and current waveforms supplied.
- Temperature rise test at maximum ODAF rating.

<u>Additional tests (must be specified in fill-in data section):</u>

- Sound level (NEMA standard test procedure used)
- Dissolved gas analysis (performed before all testing and after dielectric testing, temperature rise testing and impulse testing)

4.13.29 <u>Shipment</u>

- Shipment will be by road oil-filled (if possible) with nitrogen blanket and proper measures will be taken to protect the transformer and accessories during transport and possible temporary storage at site.
- Shipping papers will include reference to customer's purchase order number and project number, ambient temperature and the gas pressure at the time of shipment.

4.13.30 <u>Warranty</u>

- A five-year on Delta Star manufactured parts is included.
- Manufacturer shall state location of service center where any necessary work will be performed.
- Warranty shall cover all components of transformer for warranty period. Manufacturer shall not pass along component warranties and under no circumstance shall buyer be required to contact the manufacturer of an individual component.

4.13.31 Evaluation of Losses and Other Evaluation Considerations (N/A)

- Should the tested losses exceed the guaranteed levels as defined in ANSI C57 standards, the seller shall pay 1.5 times the difference in the total operating costs. No credit shall be given for tested losses which are lower than the guaranteed values.
- Loss measurement test equipment shall be calibrated and traceable to NBS Tech note 1204.

4.13.32 Other evaluation considerations:

- Consider proximity of plant
- Availability of field service
- Quality of unit
- Previous experience with manufacturer

4.13.33 Specific Proposal Data

Customer RFQ #	TBD	
Manufacturer Proposal #	TBD	
Manufacturing/Assembly Plant Location	DSE or DSW	
Country of winding material origin	USA	
Country of core steel origin	USA, Japan	GB
Country of insulation origin	USA	
Country of oil origin	USA	
Location of repair facility for performing any repair work	DSE	
MVA ratings & cooling class	___67	MVA ODAF
High voltage/BIL	__115/550	kV
Low voltage/BIL	___46/250	kV – all LV windings leads to be brought out through bushings
Tertiary voltage/BIL	2.3/110	kV convertor connected
Vector relationship	___DY1d	
Temperature rise of winding Temperature rise of oil Impedance Frequency	95 65 17.5 60	˚C ˚C % Hz
Sound level at rated MVA	83	dB(A)
Make/model of HV arresters	TBD	

HV bushing make/model	TBD	
Primary taps (full capacity, de-energized)	±(2)-2.5%	
Make/model de-energized tap changer	DSI	
Rated BIL of de-energized tap changer	650	kV BIL
Rated current of de-energized tap changer	250	Amps
Nominal secondary voltages	33	kV
Winding material used	Copper	
Turn insulation material	Nomex	
Key spacer insulation	Nomex/TUK	Per C57.154
Make/material of winding tube	Weidmann	
Make/material of upper/lower pressure plates	Rochling	
One-piece, full-circumference pressure plates	Yes	Yes/no
Method of final coils sizing	Yes	Hydraulic press
Method of mechanical stress calculations (remembering that (yield stress) / (design stress) = (safety factor)	FEA	FEA/hand/Program?
HV tensile strength safety factor		During design
Turn-insulation compression safety factor (worst disk)	___________	
Final pre-load stress on pressure plate	___________	PSI
Would final design & yield stresses be made available?	___________	
Method of routing internal leads from coils to bushings	___________	

Method of making conductor/lead connection	___________	Brazing vs. Crimp
Material of studs used on outside of tank	Stainless	
Transformer oil preservation system	___________	Sealed/Regulated
MCOV ratings of LV arresters	115	kV
Test equipment calibrated/traceable to NBS Note 1204	Yes	Yes/No
MVA of ANSI Temperature test	____67	MVA
Impulse test performed on all bushings	____Yes	Yes/No

Table 10: Transformer PRD

<u>4.14 Transformer CAD Design:</u>

In accordance with the above specifications, our partners at Delta Star Inc. developed a final design for the same as seen in Figures 12.

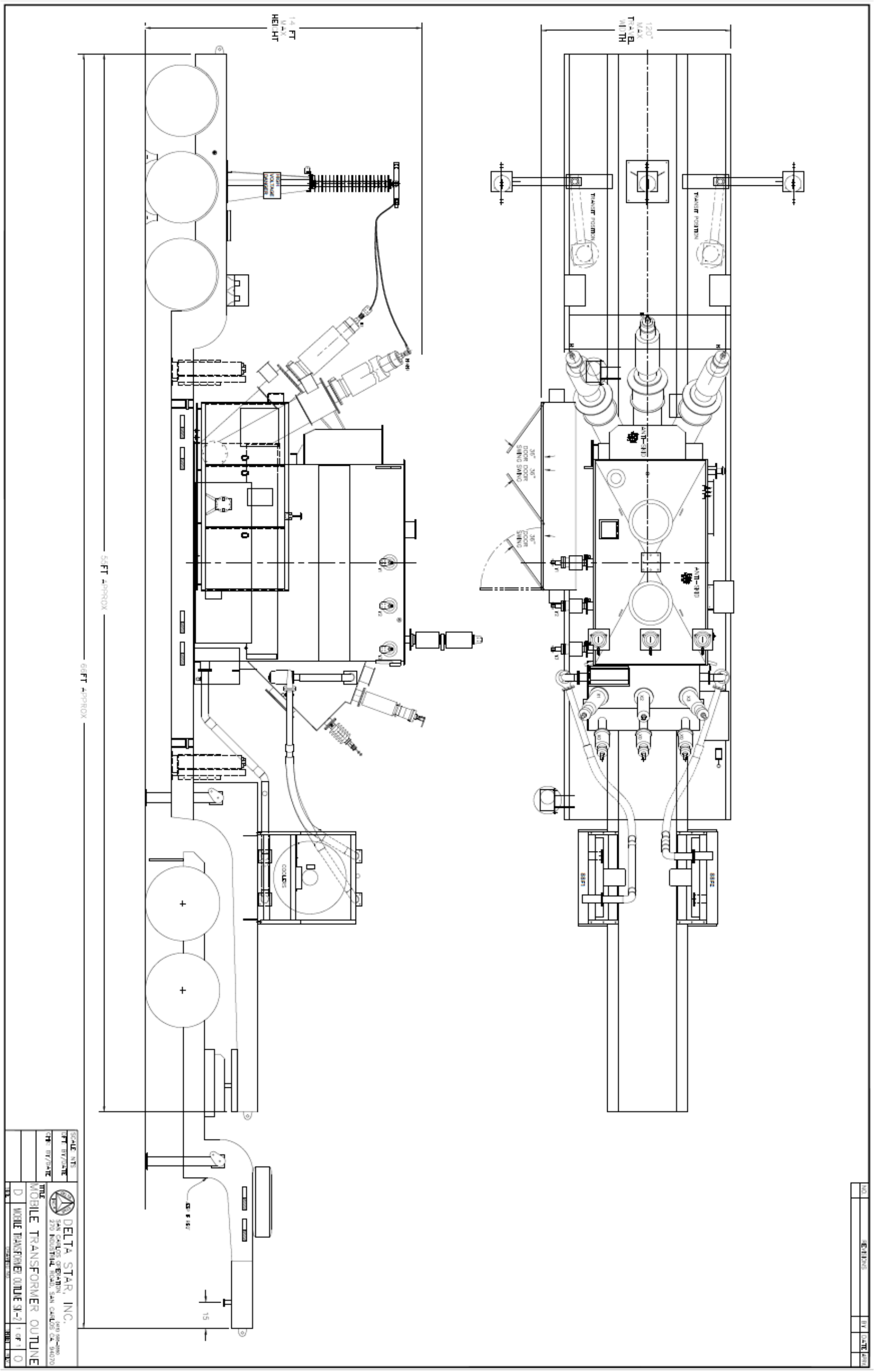


Figure 12: 56 MVA Oil Natural Air Forced Cooling Transformer

4.15 System-Level Analysis

In order to understand the correct injection patterns for the proposed topology, a few scenarios were generated on a standard IEEE 30 bus case. The analysis was conducted in OpenDSS using scripts written in MATLAB. The subsequent section presents the frequency domain model used for the same.

4.15.1 Frequency domain model

In the frequency-domain model, the MCT is modeled as a passive transformer providing voltage step-up/stepdown functionality and as active and reactive power injection at transformer (sending-end)bus and receiving end bus, as shown in Figure 13. In this model, the dynamics of the DC-link voltage are ignored. The active- and reactive-power equations of the model are given by the following equations

$$P_{ser} = \frac{V_{out} * V_2}{X_{line}} * \sin(\delta + \varphi)$$

$$Q_1 = Q_{1,ser} + Q_{1,sh}$$

$$Q_{2,ser} = \frac{V_2}{X_{line}}(V_2 - V_{out} * \cos(\delta + \varphi))$$

where $Q_{1,ser} = \frac{V_{out}}{X_{line}}(V_{out} - V_2 * \cos(\delta + \varphi))$,

$Q_{1,sh} = \frac{2nV_1}{2X_{diff}}(2nV_1 - V_{diff} * \cos(\delta + \emptyset_{diff}))$,

$V_{out} = \sqrt{(V_1^2 + V_{conv}^2)}$,

$\varphi = \tan^{-1}\left(\frac{V_{conv} * \sin\theta}{V_1 + V_{conv} * \cos\theta}\right)$,

P_{ser} is the active power injection at sending-end bus,

Q_1 is the reactive power injection at sending-end bus,

$Q_{2,ser}$ is the reactive power injection at receiving-end bus,

V_1 is the sending-end voltage,

V_2 is the receiving-end voltage,

δ is the phase angle between the two buses,

V_{conv} is the magnitude of PR injected series voltage,

θ is the phase of PR injected series voltage,

X_{line} is the line impedance,

V_{diff} is the magnitude of power router differential voltage,

$\emptyset_{diff}$ is the phase of power router differential voltage,

X_{diff} is the differential impedance,

and n is the tap ratio.

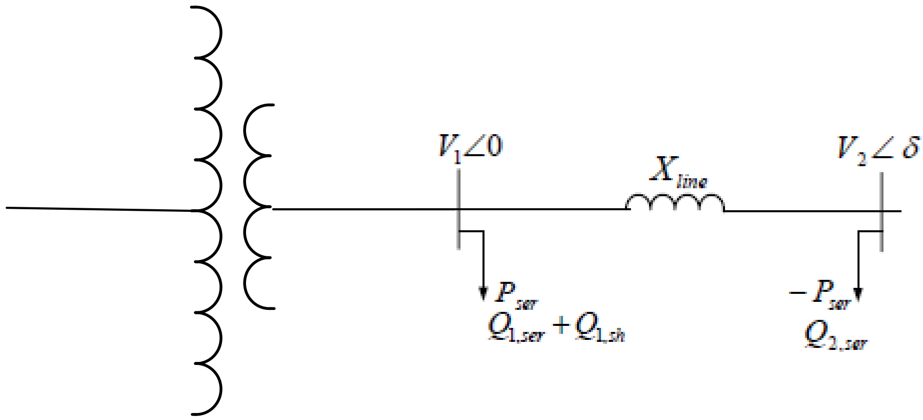


Figure 13: MCT frequency domain model

4.15.2 Base Case Analysis

The system being investigated is a standard IEEE 30 bus system. The system was chosen owing to the meshed downstream nature of the topology which is a characteristic of this application.

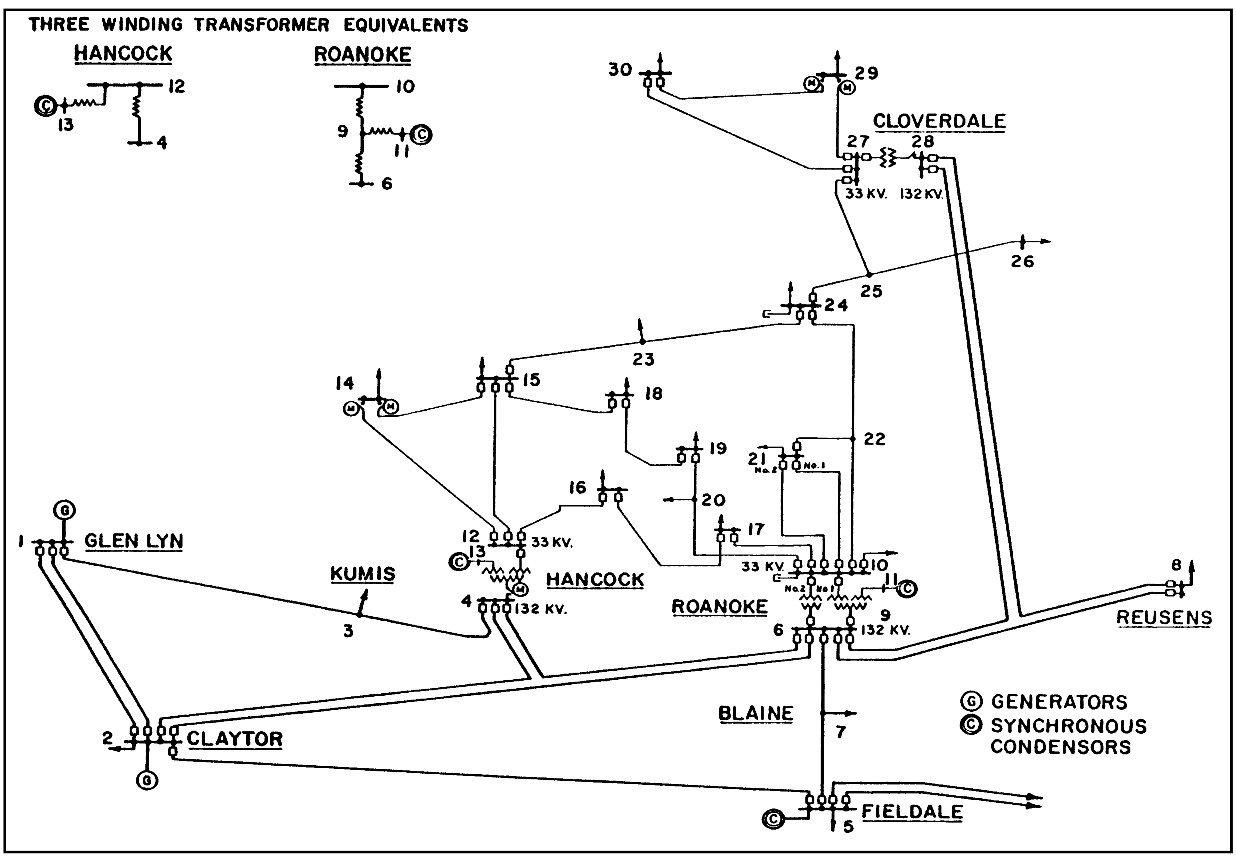


Figure 14: IEEE 30 bus case

A slight modification is presented here where the transformers between bus 4 and 12 and bus 6 and 10 are replaced by one 100 MVA, three winding transformer each. It is seen that owing to the meshed nature of the system, the power flow takes place through these two paths.

For our applications, these transformers are named ‘T4-12’ and ‘T6-10’ corresponding to the buses they lie between. The base case power flows and per unit impedances are summarized in Table 11.

	Impedance (pu)	Rating (MVA)	Ratio	Base Case loading (MVA)
T4-12	15	100	132/33 kV	51.8
T6-10	15	100	132/33 kV	42.2

Table 11: Base Case Transformer Specifications

The system consists of multiple Synchronous Condensers ensuring that the reactive power flows are slightly decoupled.

4.15.3 Range of Power Flow Control

Active injection also allows dynamic power flow control on meshed networks (Figure 15). By changing the phase angle on the bus, active power flow control can be achieved.

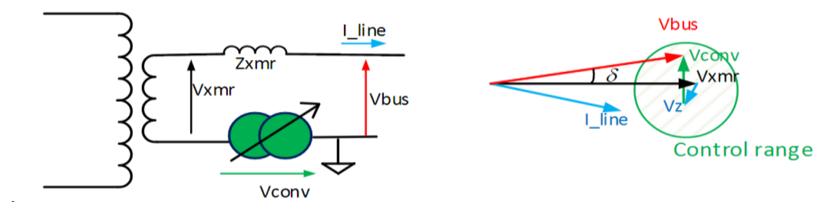


Figure 15: Range of Active Power flow control

An analysis was conducted to observe the full range of power flow achievable through active injection. On the test system, a constant 5% injection magnitude was maintained while varying the phase angle over the full range of 360 degrees.

Figure 16 shows the full range of active power flow variation on all three units. As expected a quadrature injection has the highest impact reducing the loading level on the area of interest to 36.9 MVA. This shows it is possible to achieve a **29% reduction in loading** over the base case.

Figure 17 shows the change in the Apparent power (Transformer loading) in response to voltage injections over the complete 360-degree range.

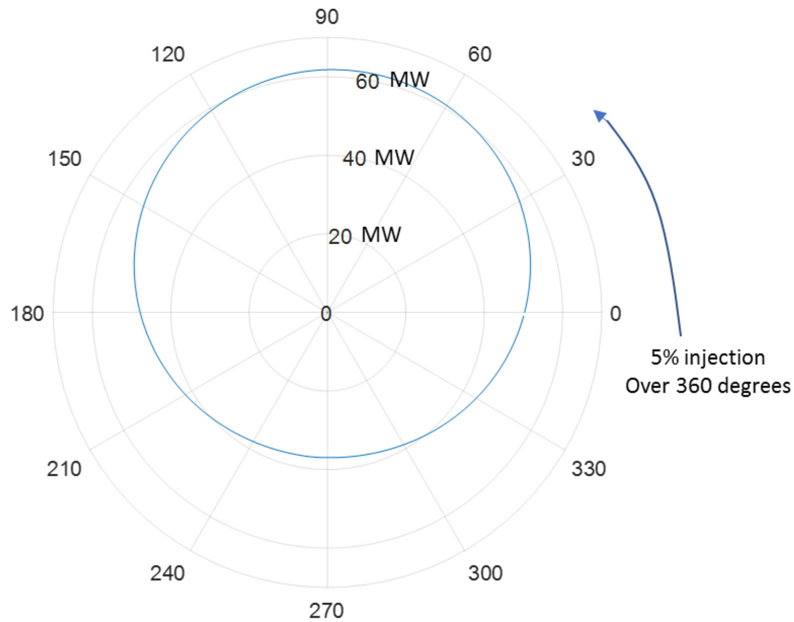


Figure 16: Active Power [MW] Variation (5% injection magnitude, over all 360 degrees)

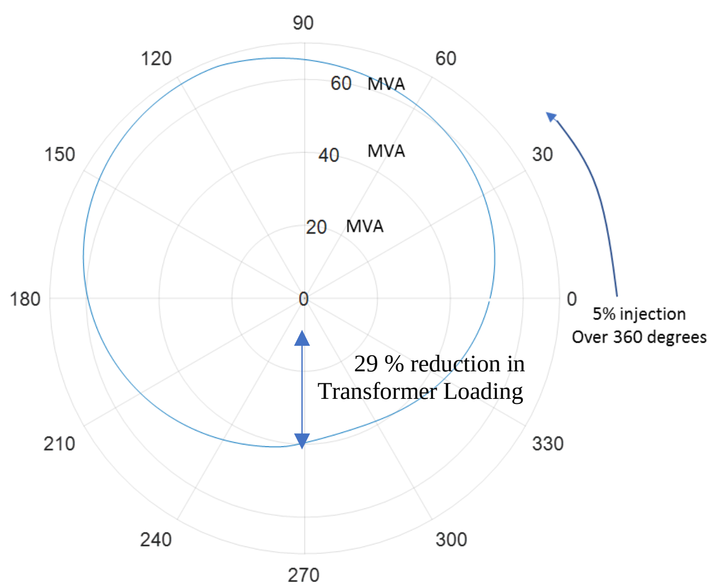


Figure 17: Apparent Power [MVA] Variation (5% injection magnitude, over all 360 degrees)

The analysis proves that a large range of control over apparent power can be achieved using the MCT approach. Almost a 6% loading change is seen per 1% of voltage injection.

4.15.4 System Level Impacts of Two Options for MCT deployment

There are two approaches that could be followed in terms of the MCT implementations:

(a) Retrofit existing LPTs with a fractionally rated converter (Figure 14).
(b) Split the MVA capacity of the LPT into two or more LPTs to achieve modularity while adding flexibility to each unit (Figure 15).

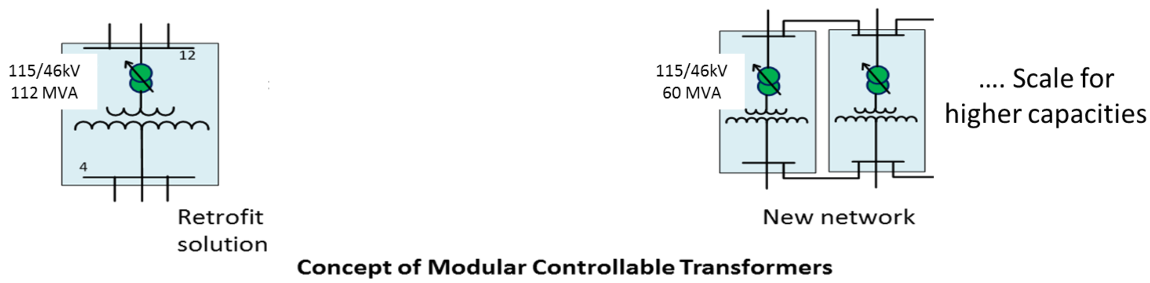


Figure 14: MCT Approach

The retrofitting option does appear appealing in terms of the cost, there are some sunk costs in terms of modifying the transformer unit to add the flexibility in the form of a converter. The costs as presented in a previous subsection reflect that very marginal savings are achieved through a retrofittable approach. The modularity embedded in approach (b) generates additional revenue stream owing the flexibility and provides higher resilience as indicated in the resilience studies performed in the previous quarters. This ensures that the modular approach is the optimal one.

Given the target 112 MVA rating the approach highlighted in approach (b) suggests replacing the LPT with two 66 MVA units. Since, the per unit value of the impedance of the corridor might not remain the same, a deviation in effective power flowing through this corridor might be observed.

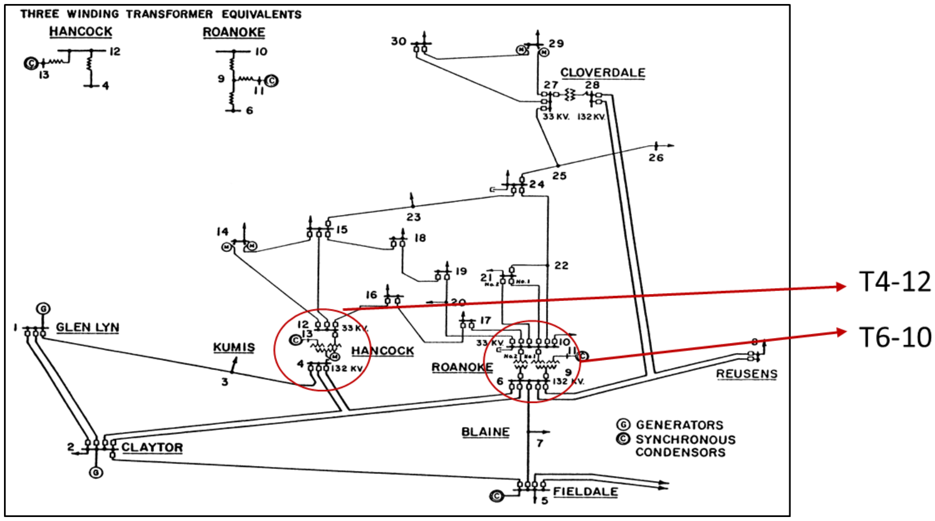


Figure 15: IEEE 30 bus system test case

However, owing to the attached converter, it is possible to drive the apparent impedance of the corridor to the original value. A simulation case was generated to demonstrate the same. The IEEE-30 bus system was used to prove the same. The base case specifications for the two transformer units are highlighted in Table 1212:

	Impedance (pu)	Rating (MVA)	Ratio	Base Case loading (MVA)
T4-12	15	100	132/33 kV	51.8
T6-10	15	100	132/33 kV	42.2

Table 12: Base Case Specifications

The MCT approach is implemented on the LPT between buses 6 and 10.Figure 6 shows how the LPT is replaced with two units; each with fractionally rated converters. Each of these units has an impedance of 9 p.u. to ensure a change in power flows with respect to the base case.

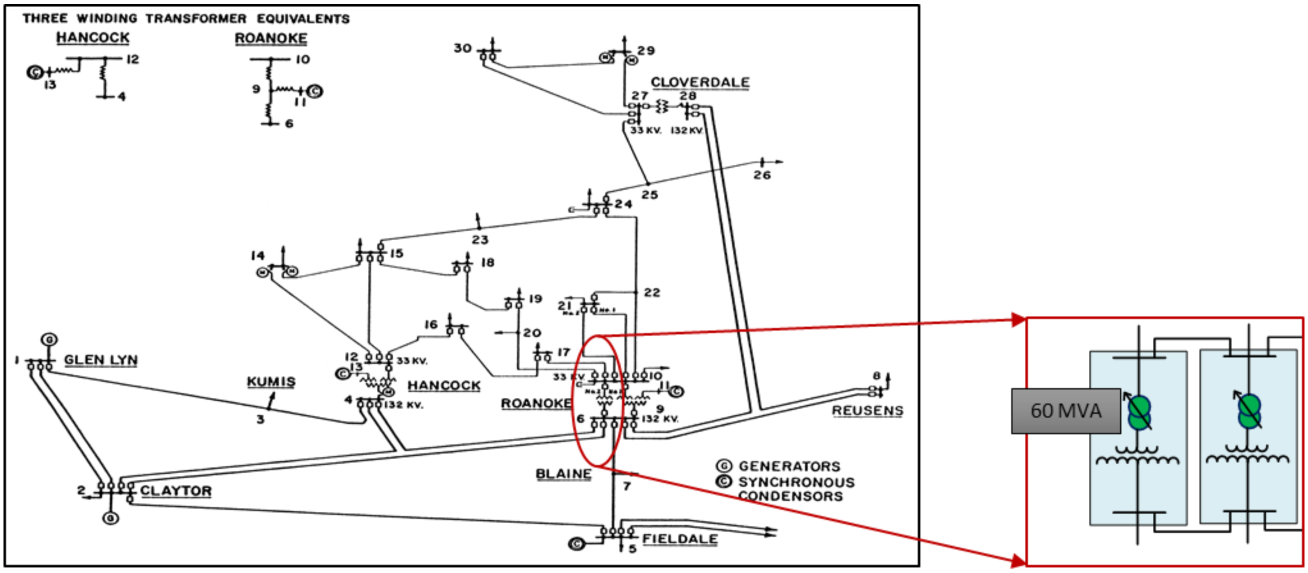


Figure 6: Simulation Case – MCT Approach

It can be shown that through added control it is possible to drive the impedance and consequently the power flowing through the said corridor to its original value. Figure 7 shows the principle of impedance control along with the impedance correction achieved.

Figure 8 shows the ability to revert to the original power flow through the corridor.

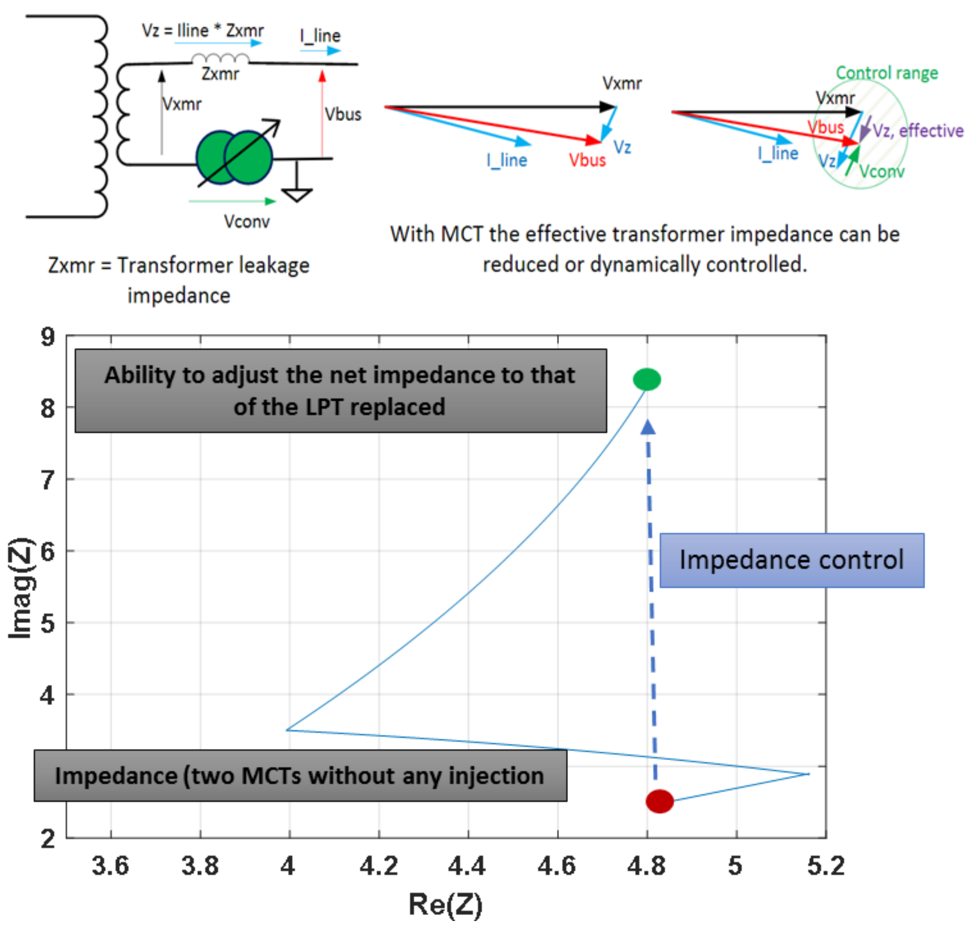


Figure 7: Impedance Control

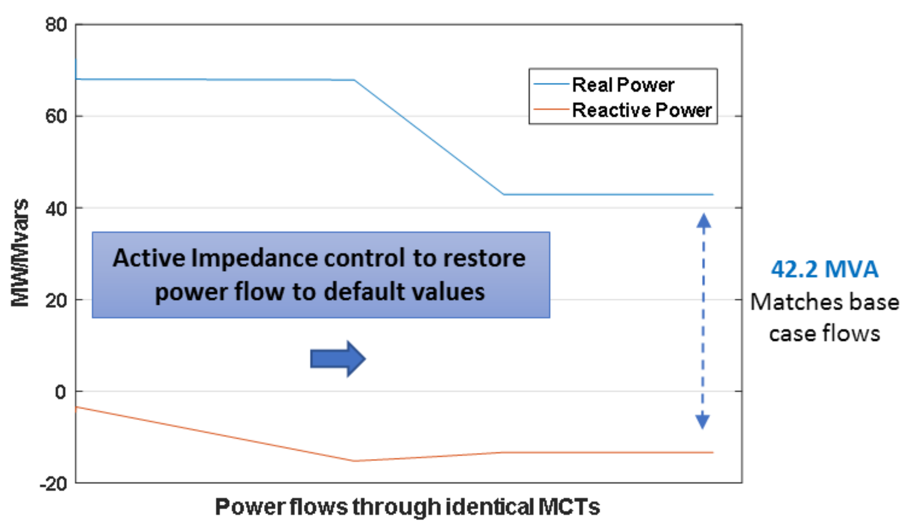


Figure 8: Power flow correction through impedance control

The simulations conducted above showcase the ability of the system to adapt to standardized LPTs ensuring scaling and modularity. In addition to this, the value added in terms of flexibility and increased resiliency owing to smaller, easily transportable units makes approach (b) attractive.

4.15.5 MCTs to handle massive DER penetration

With increasing amounts of DERs like wind and PV on the system, the system gets congested in patterns that are strongly linked to the impedances in the system. Components like transformers and lines could easily be stressed under such circumstances. The first line to get loaded fully usually limits the amount of energy that can be absorbed into the system. The rest of the energy simply has to be spilled. However, the net utilization of the system is usually much lower than the peak capacity. MCTs allow efficient use of multiple transmission corridors while reducing the amount of energy that has to be spilled. Figure 23 shows the schematic of the system with 1.1 MW of PV capacity installed at Bus 16. The PV farm is assumed to follow the output pattern shown in the same figure.

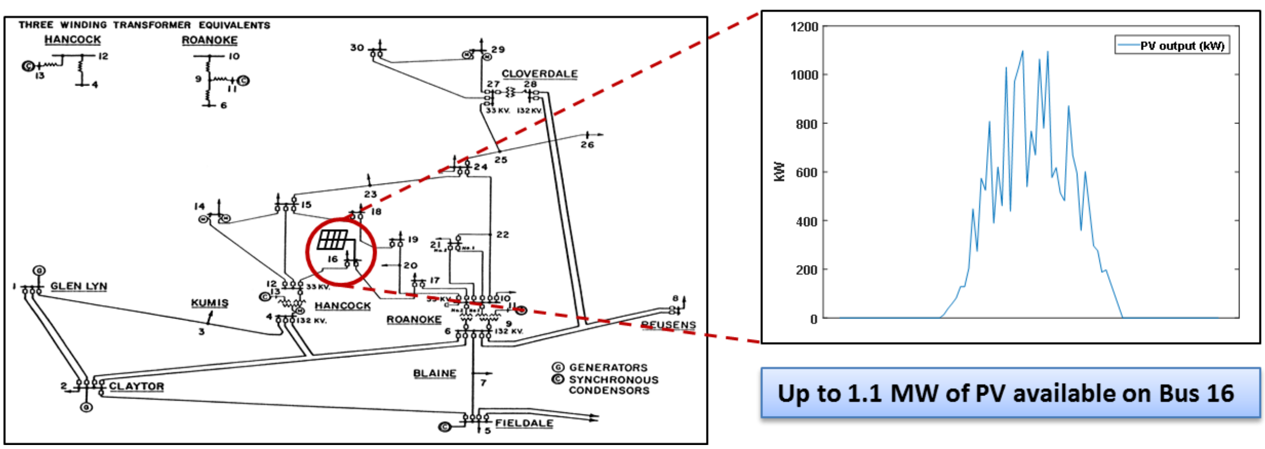


Figure 23: IEEE 30 bus system with PV penetration

It is observed that line 15-18 gets overloaded to 107% of its capacity (Figure 24). In order to solve this about 812 kW of power has to be spilled. MCTs allow dynamic changes in power flows across the said topology. Figure 25 shows that with MCTs between buses 6 and 10, the power flow patterns can be altered to keep line loading under 100% over the course of the day.

Hence, the control added through the MCT approach allows dynamic reconfiguration of system flows enhancing DER penetration. This has implications in avoiding lengthy interconnection studies and increasing the reconfigurability of the system.

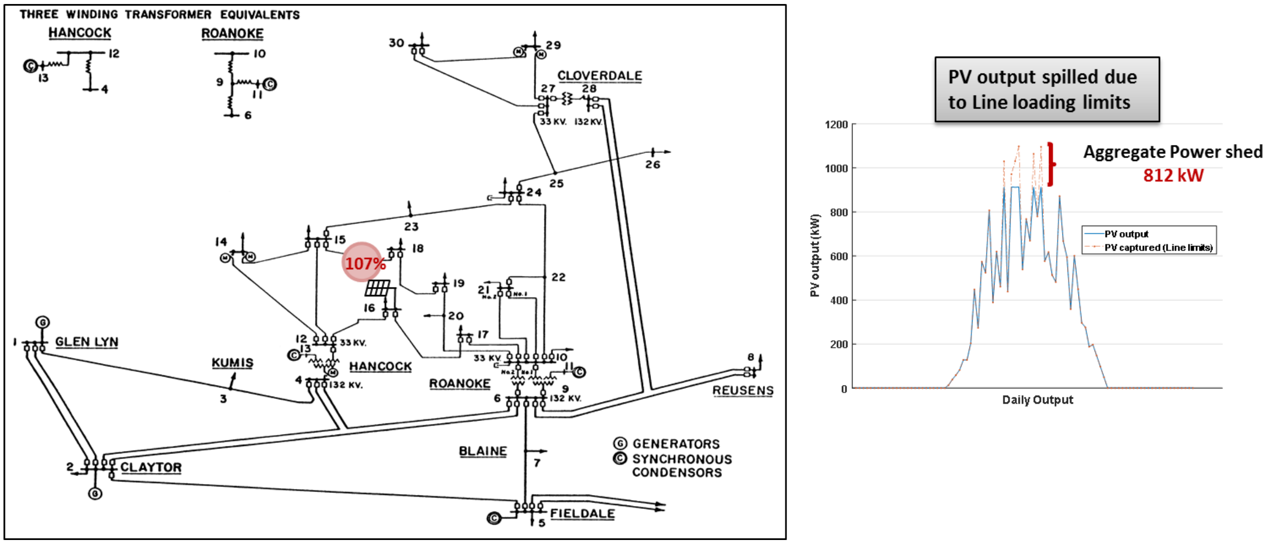


Figure 24: Line 15-18 overloaded / PV spilled

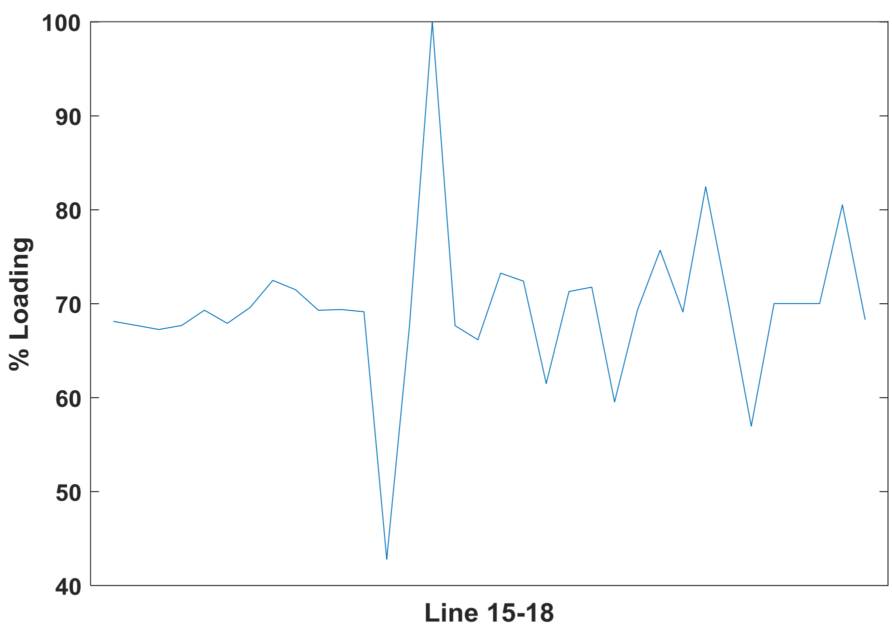


Figure 25: Power Flow over Line 15-18 kept under capacity

4.15.6 Dynamic LTC application

Voltage volatility is the hallmark of systems with large amounts of PV. Typical feeders are equipped with mechanical LTCs that switch to maintain the voltage on said feeders. However, frequent switching of LTCs causes stress on the mechanism and degrades the unit. Moreover, the fixed taps on the LTCs can only correct the voltage in discrete steps. With the ability to control voltage injections through MCTs, dynamic control over voltages can be achieved in a more granular fashion with much faster response times.

Figure 26 shows a 13 bus feeder system that was considered for the same. The PV injection creates voltage changes. The voltage profile at bus 680 is shown in the same figure with and without the use of an LTC. It is seen that LTCs do correct the voltage profile within a certain tolerance range.

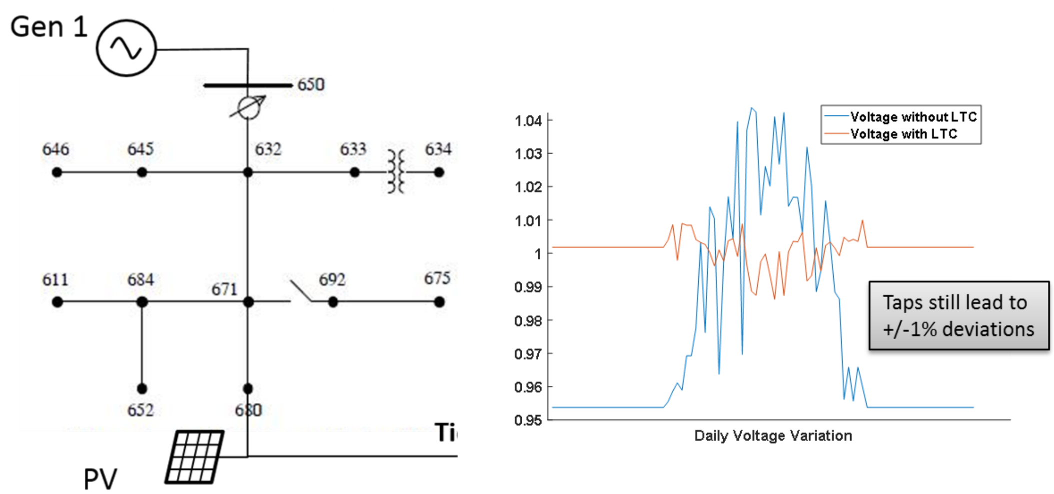


Figure 26: Mechanical LTC performance with PV penetration

By adding an MCT unit at the same transformer the voltage profile can be optimized further. Figure 27 shows that a smooth voltage profile can be achieved with a maximum of 2.6 % voltage injection.

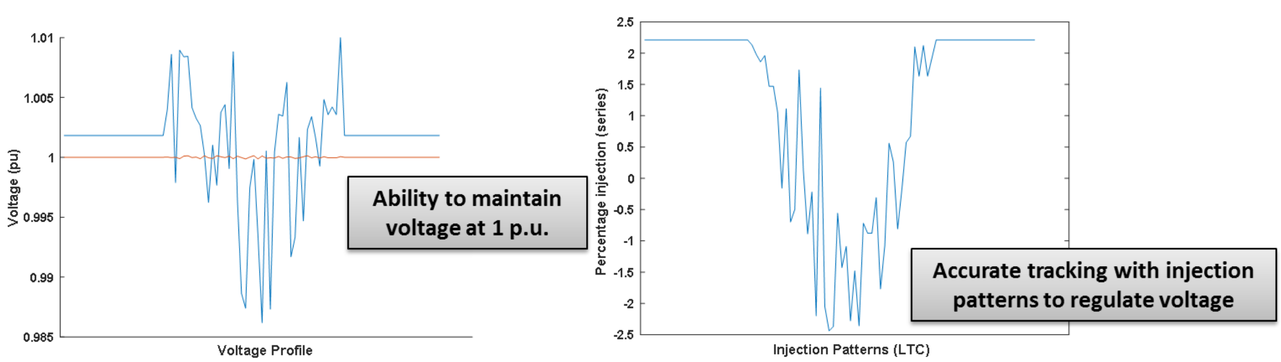


Figure 27: Dynamic Voltage correction using MCTs

4.15.7 Decoupled Power Flow Control over tie lines

A hybrid system constructed with two 13 bus systems is shown in figure 28. Here, the objective is to showcase the MCT's ability to control power flows between different areas. As seen in figure 29 it is possible to achieve completely decoupled active and reactive power flows over the tie line. Up to 200 MVA of power is controlled using three MCT units.

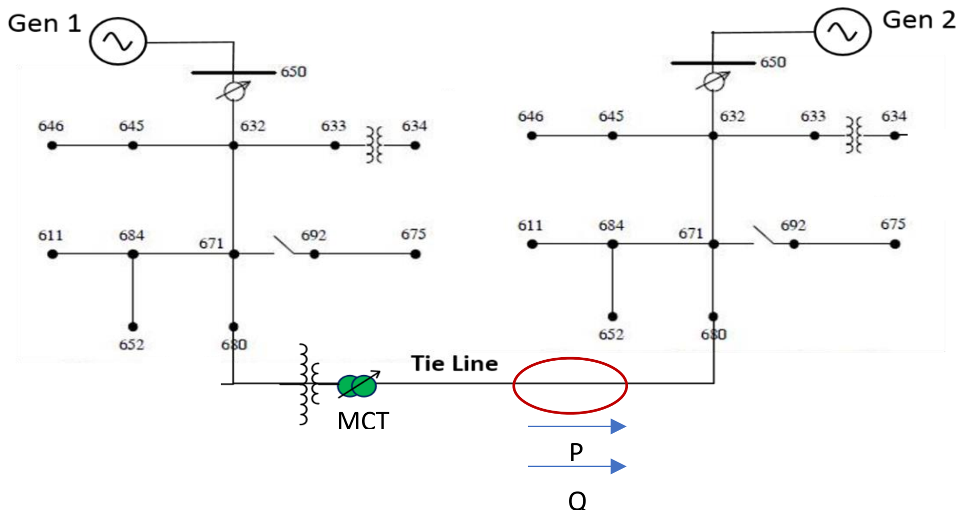


Figure 28: Two area power system

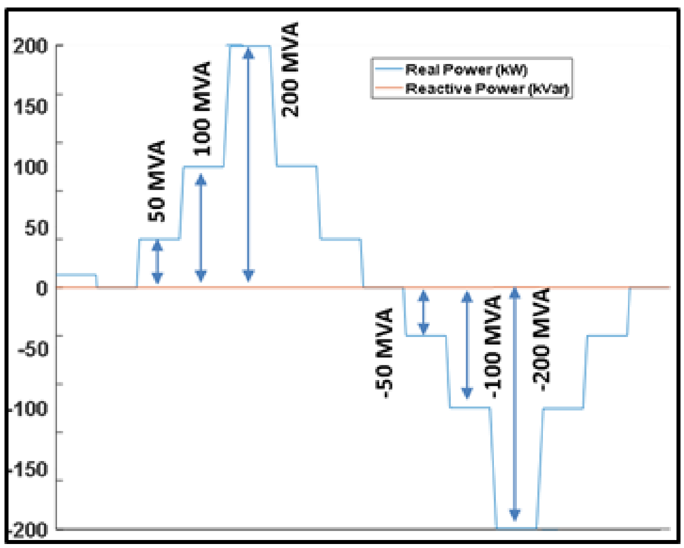


Figure 29: Active Power Flow control over tie lines

The series of system simulations conducted here showcase the system level impact that this approach has. In the subsequent sections, it is shown that this approach is an extremely cheap way of achieving the same. Along with the improvement in resiliency, significant benefits can be obtained even during nominal operation of the system using MCTs.

4.15.8 Reduced Recovery time

The scenarios presented here mimic the actual replacement process followed in the industry. In the face of a contingency, a utility could:

- Wait for a replacement (12 months)
- If a spare is available, ship it to the location (1month)
- Ship a mobile transformer and wait for the replacement to arrive (1+11 months)
- Use the MCT approach.

Figure presents the load lost if each of these approaches is followed. The numbers here are consistent with the analysis presented above.

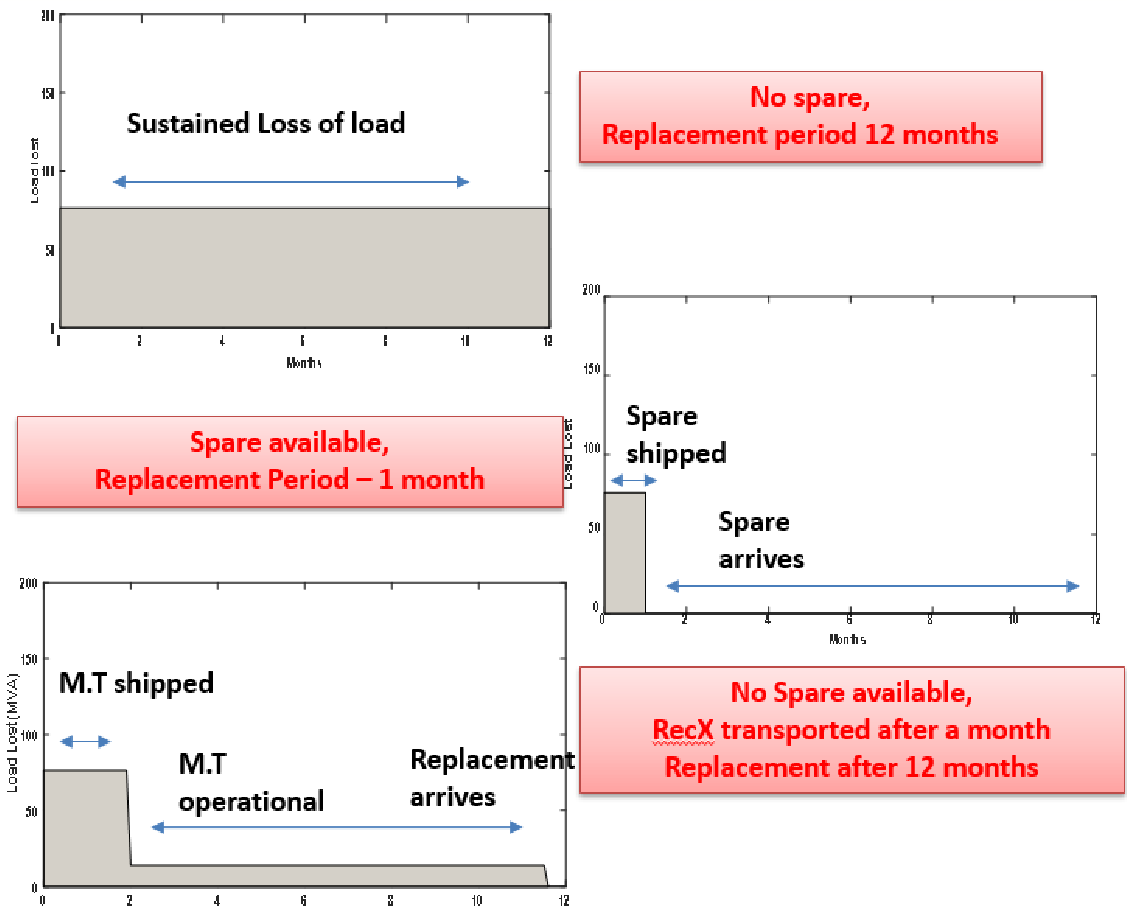


Figure 30: Recovery Time Analysis

With MCT units in the system the load lost due to a contingency can be kept at zero making it a highly resilient approach.

Table 13 presents a cost in terms of MW-months lost.

Table 13: Cost of each option

Response	**Cost**
No Spare, waiting for replacement	915.6 MW-months
Mobile Transformer (M.T) followed by replacement	230 MW-months
Spare Available (Shipped in a month)	76.3 MW-months
MCT	0- Negligible owing to instant dynamic control

Although using a spare seems attractive in this context, the unavailability of a spare for the diverse range of transformers in the system makes this response impractical. The unit used to quantify costs (MW-months) needs to be translated to a monetary value. The relationship between these two needs to be analyzed in order to definitively understand the cost of each approach. Other related costs need to be factored in to refine the resiliency metric further. However, in some sense the data clearly points towards higher resilience using the MCT approach.

4.16 MCT Cost Analysis

Three options were investigated as viable solutions to replace aging LPTs (Figure 31). Option 1 is the traditional approach which consists of replacing the aging LPT with a new one. Option 2 consists of replacing the LPT while retrofitting it with a converter to add flexibility. Option 3 highlights the modular approach which consists of replacing the LPT with smaller modular transformers; each retrofitted with a converter to increase flexibility.

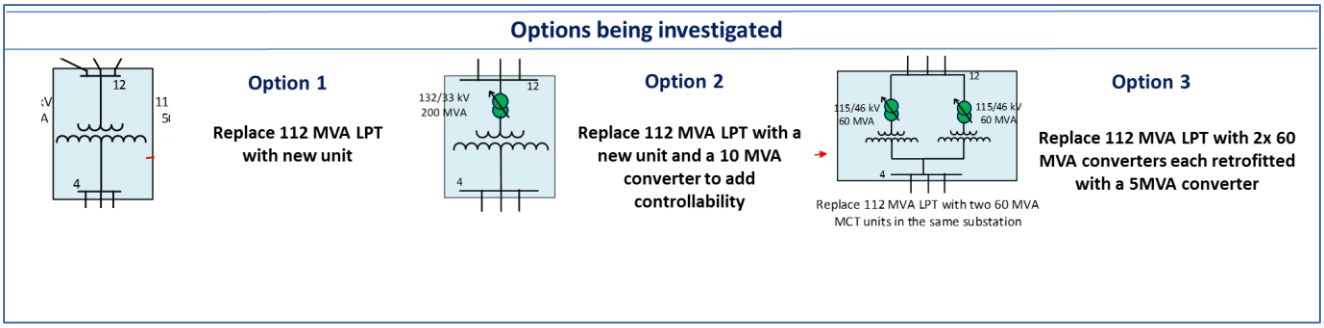


Figure 31: LPT Replacement Options

A list of assumptions is proposed here. These assumptions were used for the cost point analysis. These numbers are being scrutinized further. However, the conclusions of this study would largely remain the same.

Assumptions

- Cost/kVA for the converter is assumed to be $100k/MVA.
- Cost/kVA for the converter drops by 15% as the size goes up 2 times.
- Cost/MVA for transformers is $30k/MVA for a 112 MVA unit and $25k/MVA for smaller units.
- Assumed carrying cost of spare transformers is $100k/year.
- Typical carrying period for a spare is assumed to be 3 years.
- For a 112 MVA option the transportation and commissioning cost is assumed to be 30% of the transformer cost owing to the additional cost of filling oil and mounting the bushings whereas, for the smaller units it stays at 15%.
- Cost of commissioning the converter is assumed to be 15% of the converter cost.
- Cost of the footprint (space requirement) is not considered here.
- Additional cost encountered in the tendering processes are not accounted for.

An initial cost analysis was conducted to understand the value of the MCT approach. The cost number presented below are subject to change depending on the manufacturer and regional specifications. However, the results presented below stay consistent even with slight variations in cost. Table 14 shows the results of the cost point analysis.

Costs	LPT Replacement	LPT Replacement + Converter	Modular Approach (2x 60 MVA Xfmr with converters)
Transformer Cost	$3.36M	$3.36M	$3M
Converter cost	N/A	$850k	$1M
Transportation and Commissioning	$1M	$1M	$450k
Transportation and Commissioning (Converter)	N/A	$127.5k	$150k
Cost of carrying a spare	$300k	$300k	None due to standardization
Total Cost	$ 4.6M	$ 5.63M	$4.6M

Table 14: Initial Cost Analysis

From the calculations, it can be seen that the cost of the Modular Approach is about the same (subject to some changing costs) as that of replacing the entire LPT. Moreover, some revenue streams cannot be monetized and reflected in the analysis here. Added flexibility has far reaching effects in terms of reduced generation costs, extension of transmission and sub transmission system lifetimes due to optimal loading and lower losses achieved due to optimal power flow. Factoring in the revenue made of these services would prove that the modular approach is the most cost effective one. Table 15 shows the value streams that can be achieved through different approaches.

Avoided Cost/ Ancillary Services	LPT Replacement	LPT Replacement + Converter	Modular Approach (2x 66 MVA Xfmr with converters)
Lower Losses due to flexibility	None	Reroute Power to reduce cost of losses	
Ability to mitigate overload to defer upgrades	None	Transformer/ Transmission Line loading maintained at optimal values	
Cost of filling oil/assembling bushings	Fixed cost		Shipped with bushings and oil
Ability to reduce generation costs due to high DER absorption	None	Embedded functionality to absorb DER output without any overloads on the system	
Operation under Contingency	Possible overloads due to uncontrolled flows	Ability to use lesser congested corridors	
Probability of Transformer Failure	If the target LPT fails all control is lost along with uncontrolled power flows		Ability to maintain control even if one MCT fails to restore system to suboptimal operation

Table 15: Revenue Streams

This shows that at roughly the same cost as that of replacing an entire LPT, the MCT approach provides added control, improved resiliency, higher revenue and redundancy across the system.

4.17 Grid Resilience Definitions and Metrics

4.17.1 Resilience Definition

In this work, we will use the following, simple definition of power system resilience:

Power System Resilience: The ability of the power system to recover quickly from events.

Along the lines of the broadly adopted operational states of the system [10-11], and inspired on new developments on system vulnerability, we stipulate the following states of the power system.

State	Description
Normal or Secure	all loads are being served AND all power system quantities are within limits AND a set of plausible events results in all the power system quantities within operational limits
Insecure or Vulnerable	Some power system quantities present violations in the present state OR for a set of plausible events power system quantities exhibit operational violations.
Disturbance	Some loss of load exists and actions are being taken to restore loads.

Power system events are formally defined as related to a power system specific reality. For instance, the disconnection of a transmission line is considered a power system event. We will call power system events as events. Note that this event can result in the system entering a vulnerable or disturbance state (loss of load), or to remain in normal state. The cause of the power system event can be physical, such a weather event or cyber, such as software malfunction or cyber-attack. Corrective actions can bring back the state to normal, preventive actions bring the system from vulnerable to normal. The relationships between states and their transitions are illustrated in following Figure.

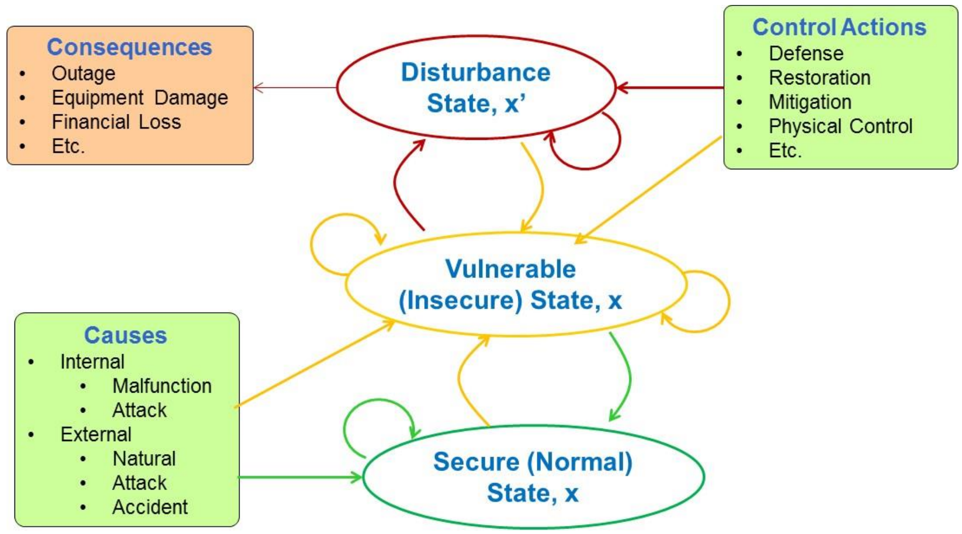


Figure 32: Power System States and Event-Driven Transitions

4.17.2 Resilience Metrics

The relation between events and resilience is therefore as follows. An event can cause a system that is in a normal operating state to enter a vulnerable state (where things can happen), or cause a disturbance, where there is loss of load, rendering the system in a disturbance state. The power system event will have a certain severity or intensity (for instance how much load is lost) and a certain duration. Note that the duration of the power system event can be larger than the duration of the cause of the power system event. For instance, load may be disconnected as a result of a tree falling on a line. While the tree has already fallen, or even if the tree is removed, the load disconnection may persist for a longer time. The power system event duration is from the time the load is disconnected to the time is restored. This is illustrated in the Figure below.

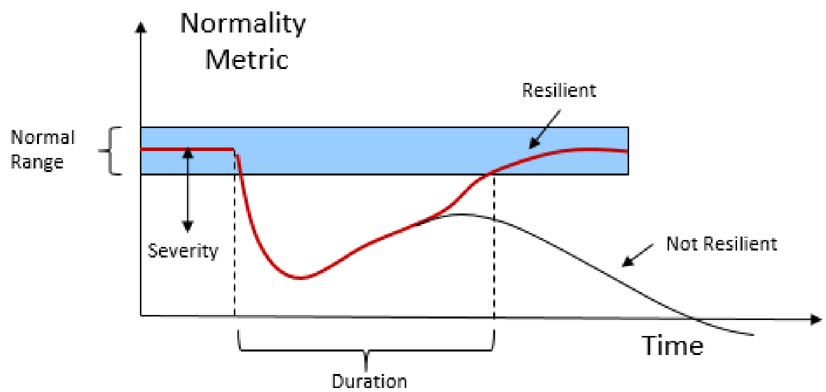


Figure 33 Event Normality and Severity metrics, and Event Duration

Let assume that a metric for the severity or normalcy of the event can be determined, such as percentage of load served. During an event, load may be lost and then the customers may be restored incrementally until everybody has their electricity service restored.

The definition of resilience includes the ability to recover, a binary qualitative feature, and the speed of restoration, e.g. the duration of the event. Various questions are therefore applicable:

a) Can the system recover from a severe event?
b) What is the most severe event that can be absorbed by the system?
c) How fast can the system recover given an event of a certain intensity?

The proposed modular transformer technology tackles these questions simultaneously. Specifically, there are three features that will be beneficial to increase resilience:

a) Due to the partial rating of the transformer to be 1/3 of the regular device, the equally probably event of losing a component (N-1) results in 1/3 of the severity of the event. Because less severe events are easier to recover from, this increases resilience.
b) Second, due to the smaller size of the modular transformer, transporting the replacement transformer and restoration of any loss of load can take place faster.

There are various mathematical definitions of reliability, associated with system stability [12]. However, in this work we are interested in simulating various technology and restoration options using modular transformers and comparing the performance of the system based on those options. The resilience of the system can therefore be associated with the integral under the curve in Figure 33. Specifically, because a system that is perfectly resilient to an event will have immediate recovery of events of any severity, we use the inverse of the integral under the curve.

$$\mathrm{R} = \frac{1}{-\int_{t=0}^{t_{restoration}} S(t)dt}$$

where:

$S(t)$: Event severity, which depents on time

R: Resilience

Example 1: Let us consider a system that experiences the following pattern of loss of load after a weather event. Let us assume the severity of the event $S(t)$ is measured in loss of load in percentage. The load served for a baseline case and an enhanced restoration case are presented.

	Baseline Case				Enhanced Case	
Time (hours)	Load Served (fraction)	Lost Load (fraction)	Duration (hours)	Block (hr x fraction)	Lost Load (fraction)	Block (hr x fraction)
t^-	1.00	0.00	0.0	0.000	0.00	0.000
0	0.50	0.50	1.2	0.600	0.50	0.600
1.2	0.70	0.30	0.4	0.120	0.20	0.080
1.6	0.80	0.20	0.8	0.160	0.10	0.080
2.4	0.88	0.12	0.2	0.024	0.00	0.000
2.6	0.92	0.08	0.4	0.032	0.00	0.000
3.0	1.00	0.00	0.0	0.000	0.00	0.000
Integral				0.930		0.760
Resilience				1.0683		1.3158

4.17.3 Security Requirements

The analysis of resilience hence seems to appear fairly straightforward. There are various considerations in realistic power system analysis that will make the analysis substantially more complex. The first one is security.

The resilience analysis and the study of power system states must consider security. In other words, the final state of the system must be assessed by considering whether additional what-if conditions can affect the state of the system. Usually power system security is evaluated by N-1 contingency analysis. A corresponding security metric is the aggregate megawatt contingency overload (AMWCO) [13,14], with units of MW. The AMWCO is a scalar quantity that can be determine to assess the impact of a contingency, the weakness of a given grid element, or the overall security of the system. AMWCO is determined by running AC power flow N-1 contingency analysis and by processing the overloads of each element under each contingency.

The system AMWCO is calculated as:

$$Sys_{AMWCO}(\mathbf{x}^0(t), S_C, S_E) = \sum_{c \in S_C} \sum_{e \in S_E} \phi_{e,c} \qquad \phi_{e,c} = \begin{cases} P_{e,c} - P_e^{\max} & P_{e,c} > P_e^{\max} \\ 0 & P_{e,c} \le P_e^{\max} \end{cases}$$

$\mathbf{x}^0(t)$: Operating state of the system at time t

$\phi_{e,c}$: overload in element e under contingency c

$P_{e,c}$: post-contingency c flow in element e

$P_e^{\max}$: rating of element e in MW

S_E: set of monitored elements $e : e \in S_E$

S_C: set of contingencies $c : c \in S_C$

The previous definition of system resilience can then be extended to include security as follows:

$$\mathrm{R}(t) = \frac{1}{-\int_{t=0}^{t_{restoration}} \left[\omega_{LL} S_{LL}(t) + \omega_{SEC} Sys_{AMWCO}(\mathbf{x}^0(t), S_C, S_E) \right] dt}$$

$S(t)$: Event severity represented by loss of load

ω_{LL}: weight for the loss of load portion of the event

ω_{SEC}: weight for the security portion of the event

4.17.4 Modular Transformers Use Cases

Motivation

Modular Controllable Transformers (MCTs) are fractionally rated transformers that due to their smaller size, power electronics features, and flexible configuration can:

1. Replace damaged conventional transformers faster than conventional transformers.

2. Reduce the impact of events on the system due to the higher reliability of modular architecture.

3. Increase the flexibility of the grid, by enabling power electronics-based control.

MCTs can prove to be of significant service to the industry by contributing to address one of the major industry concerns, namely, the possible sever impact of attack or events on bulk transformers. Hence the modeling and impact of MCTs on the grid and the industry must be better understood from the point of view of technical operation and economic benefits. It is also necessary to design a roadmap for their integration into the bulk electricity infrastructure, in particular, how MCTs affect power system resilience, and hence planning, operation, and control processes. This section explores the portfolio of potential use cases and applications of MCTs.

As discussed in previous sections, in the case of event or attack, it is difficult to quickly repair or replace bulk power transformers. However, if instead the system contains modular transformers, failure of one element results in the subsystem ability to still provide transforming action, although at a lower MVA rating. In addition, the transformer component can be repaired or replaced much faster. Combined, these two feature results in: a) disruption of less intensity, and b) disruption of shorter duration.

Modular transformers are also equipped with power electronics capabilities, which makes the system more flexible both during normal operation and under disruption. MCTs can both alter the distribution of flows through the transformer by injecting a quadrature voltage (altering the reactance) to modify active power flows, and by injecting a voltage to alter reactive power. Thus, the capability is similar to a 4-quadrant power flow router, or a power flow router in combination with a SVC. This capability is similar capability to a UPFC, but with modular characteristics and potentially less cost. Flexible control of power flows can have a beneficial impact on the system state, and it can open a number of desirable value propositions.

The purpose of this section is to explore various MCT applications to develop a MCT *application portfolio.* This portfolio will provide utilities an overview of the broad range of applications of MCTs to enhance system resilience.

For discussion purposes, we utilize several sample cases. For instance, a sample case is the 5-bus, 4-line, 2-transformer system described in Figure 34. MCTs devices are installed to replace the transformer between buses 1-5.

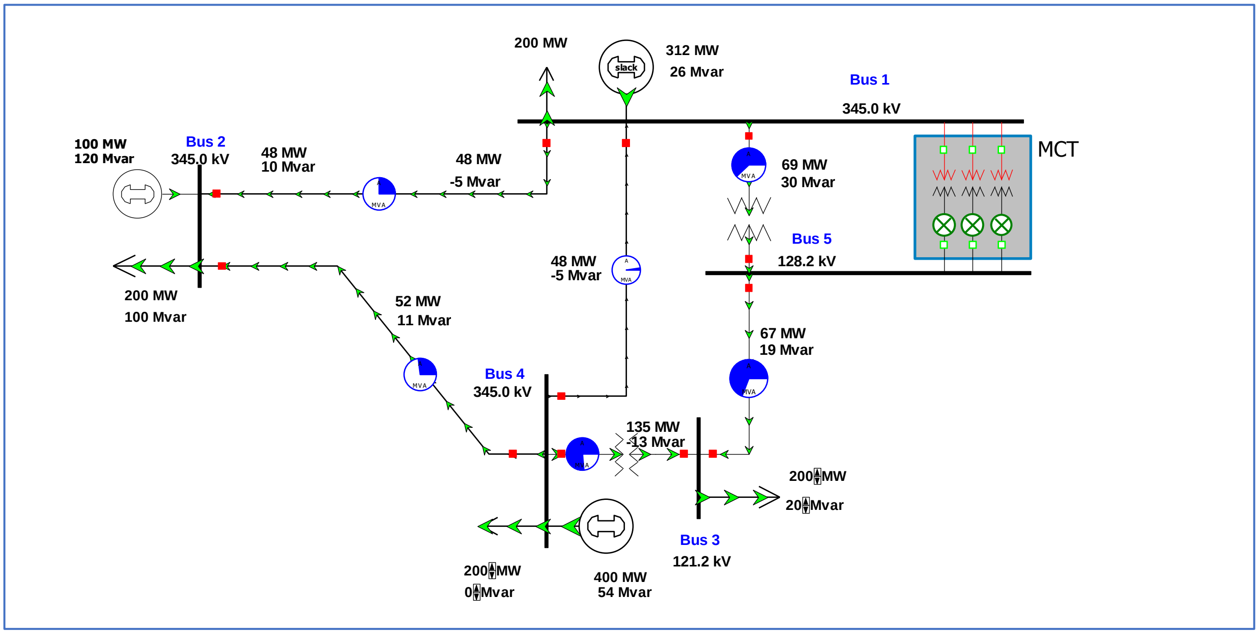


Figure 34: Application Portfolio Development: 5-bus reference system

The reference case has the MCTs disconnected, while the MCT cases open the bulk transformer and connects the MCTs to simulate the appropriate use case. In this document, we classify the MCT applications between *static applications*, in which the controls of the transformers remain fixed, and *control applications*, in which the MCT controls are allowed to operate automatically.

4.17.5 Static Applications

Increased N-1 Security

Electric power systems must operate in a secure manner during normal operation as well as during a set of plausible contingencies (such as outage of transformers). The pre-contingency state is optimized by a set of overlapping decision functions from planning to real-time security-constrained economic dispatch (SCED). When an event occurs, either: a) there are no operating violations in the system, or b) the system controls allow the system to change its post-contingency state to one without violations. In some cases, this requires automatic load shedding.

Figure 35 illustrates the analysis of the N-1 security of the system for the reference case and the case with MCT. Table 16 Provides the corresponding N-1 contingency analysis results.

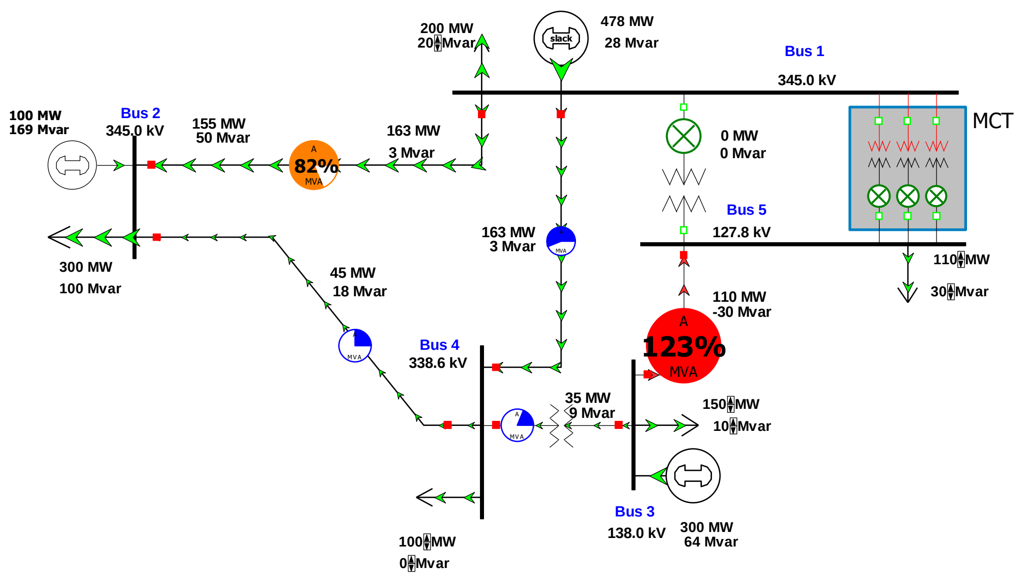


Figure 35: Post-Contingency State. Reference Case with outage of the Conventional Transformer.

Table 16: N-1 Contingency Results for Reference Case

	Label	Skip	Category	Processed	Solved	Violations	Max Branc	Min Volt
1	T_000003Bus3-000004Bus4C1	NO		YES	YES	1	151.702	
2	T_000001Bus1-000005Bus5CX	NO		YES	YES	1	123.129	
3	L_000001Bus1-000002Bus2C1	NO		YES	YES	1	117.047	
4	T_000002Bus2-000004Bus4C1	NO		YES	YES	1	107.149	
5	T_000001Bus1-000005Bus5C1	NO		YES	YES	0		
6	T_000001Bus1-000005Bus5C3	NO		YES	YES	0		
7	L_000005Bus5-000003Bus3C1	NO		YES	YES	1		0.862
8	T_000001Bus1-000005Bus5C2	NO		YES	YES	0		
9	L_000004Bus4-000001Bus1C1	NO		YES	YES	0		

We see that this case has 5 violations, four thermal and one voltage, and that the outage of the transformer is responsible for an overload of one line at 123.12%.

Figure 36 illustrates the system for an outage of one of the modules of the MCT. The full N-1 results are presented in Table 17.

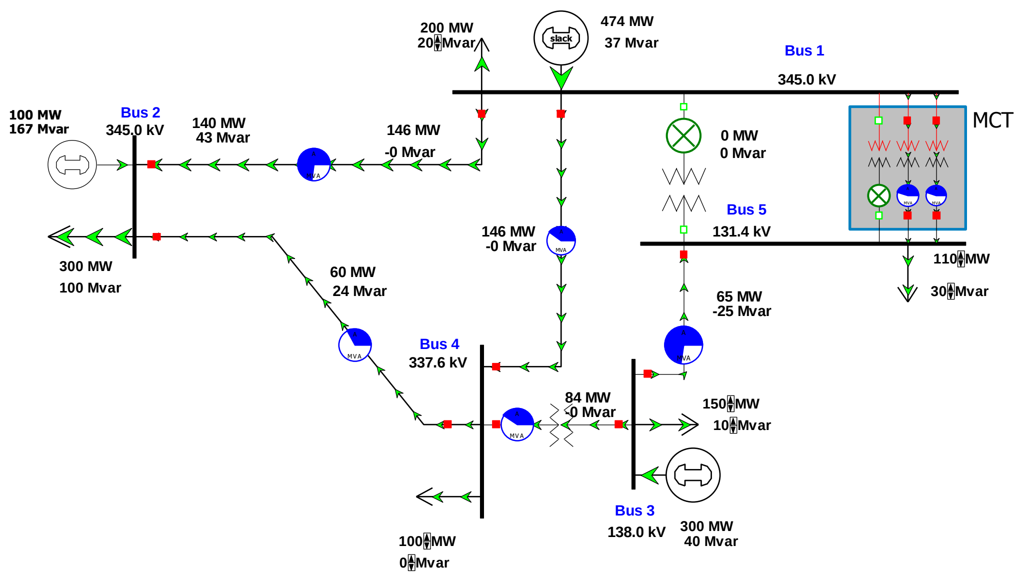


Figure 36: Post-Contingency State. Outage of a module of the MCT.

Table 17: N-1 Contingency Analysis results for the Case with MCTs

	Label	Skip	Category	Processed	Solved	Violations	Max Branc	Min Volt
1	T_000003Bus3-000004Bus4C1	NO		YES	YES	1	151.702	
2	L_000001Bus1-000002Bus2C1	NO		YES	YES	1	117.047	
3	T_000002Bus2-000004Bus4C1	NO		YES	YES	1	107.149	
4	T_000001Bus1-000005Bus5C1	NO		YES	YES	0		
5	T_000001Bus1-000005Bus5CX	NO		YES	YES	0		
6	T_000001Bus1-000005Bus5C3	NO		YES	YES	0		
7	L_000005Bus5-000003Bus3C1	NO		YES	YES	1		0.862
8	T_000001Bus1-000005Bus5C2	NO		YES	YES	0		
9	L_000004Bus4-000001Bus1C1	NO		YES	YES	0		

We note from the results, that the MCT has resulted in no actual contingency violations from the outage of one of the transformer modules. In general, the security of the system will tend to be increased due to the redundant nature of the MCT.

Increased Resilience due to Less Impact of Outage and Faster Replacement

Consider the reference case without line 3-5. In this case the load at bus 5 is served exclusively by the transformer as shown in Figure 37. An outage of the conventional transformer will result in complete disconnection of the load. When the conventional transformer is replaced by the MCT, an outage of the MCT module results in:

a) Only a portion of the load being outaged, and

b) An outage that has less duration, since the modular transformer can be replaced faster.

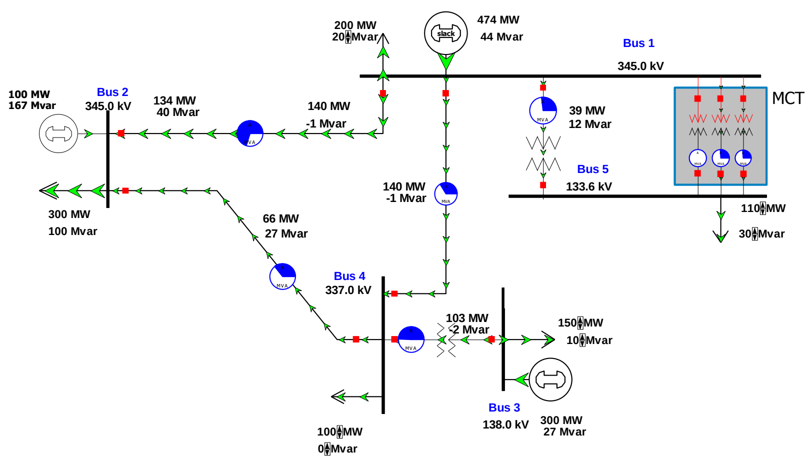


Figure 37: Reference case, assume radial service to the load through the transformer (Either the conventional transformer or the MCT is simulated at a given time)

The load at bus 5 in the case is 110MW. The capacity of the transformer is 150MVA and that of each modular transformer is 50MVA. Therefore, under an outage of a module of the MCT, approximately 10 MW will not be able to be served by the two remaining modular transformers. Let us also assume that the modular transformer can be replaced in half of the time it takes to replace the conventional transformer. The improvement in resilience is illustrated on Figure 38, which shows less impact and less duration of the event (red curve).

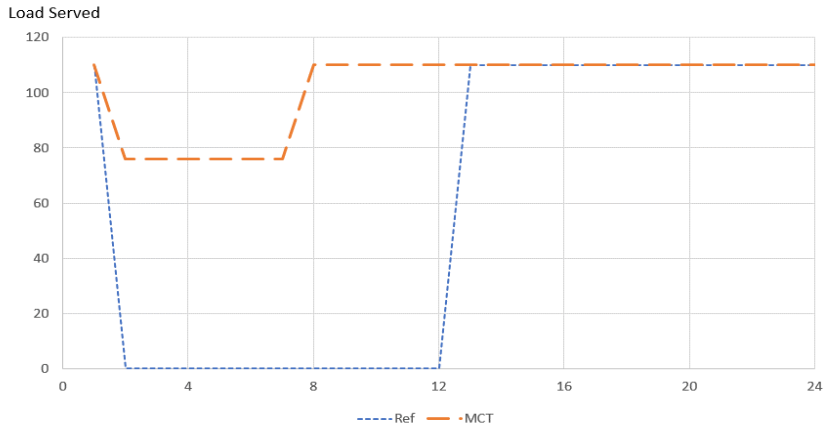


Figure 38: Resilience Levels of Served load without (reference) and with the MCT.

Increased Transfer Capability and Asset Utilization

The increased level of N-1 security obtained with the MCT allows for larger transfer and higher asset utilization. In the reference state, the load at bus 5 was 110MW. An outage of the conventional transformer will result in a violation of the thermal flow on line 3-5 of about 23%. A low shedding of 15MW of the load at bus 5, to 95 MW results on a secure post-contingency state as illustrated on Figure 39, with the flow of line 3-5 at 100%.

This is compared with Figure 40, which illustrates the outage of an MCT. In this case line 3-5 is not overloaded. The load at bus 5 could increase from 95 to 172 before line 3-5 reaches its full loading. This represents an increase in transfer capability of 77 MW (81%) for a transfer from the slack bus to the load at bus 5.

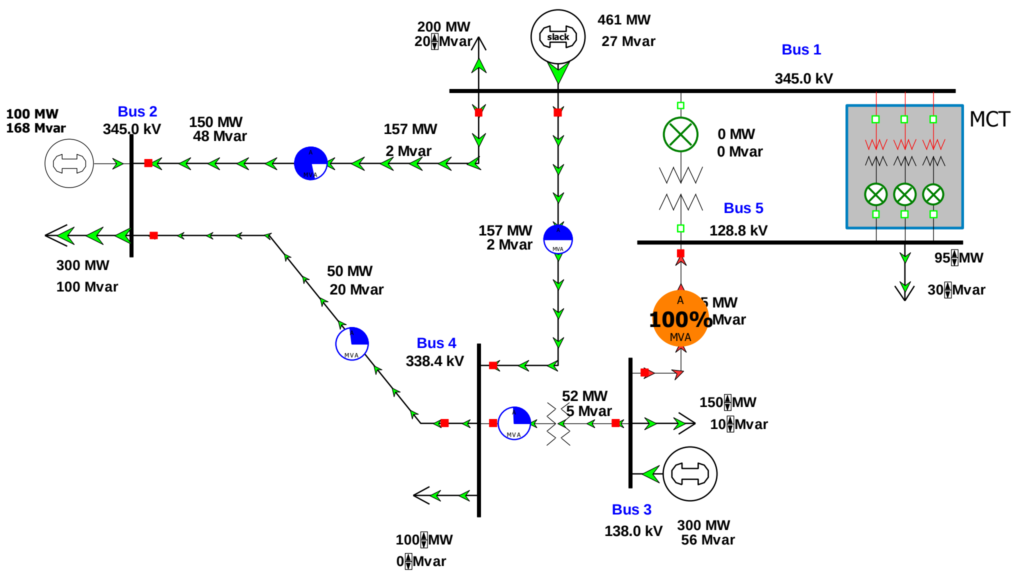
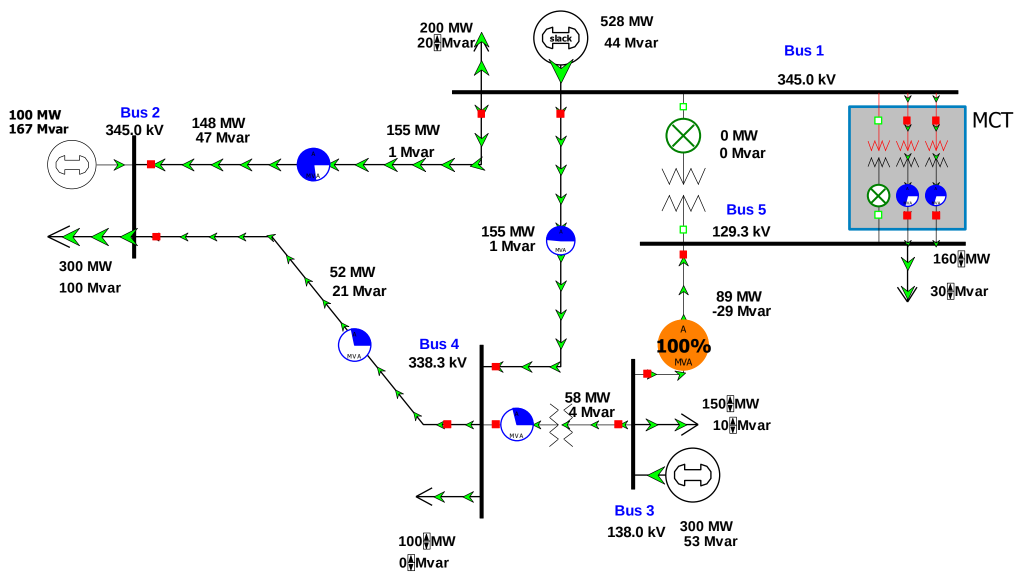


Figure 39: Transformer Outage results in 15 MW of Load Shedding (Total Transfer Capability of 95MW)
Figure 40: Outage of MCT results in a Total Transfer Capability of 172 MW

When one considers the asset utilization, it is clear that the presence of the modular transformer will allow higher utilization of both the transformer and line 3-5 (and possibly other lines in the system). The base case with the MCT can have 160 MW of load at bus 5, with 89 MW flowing on line 3-5, and 71 MW flowing across the MCT, as illustrated in Figure 41. The reference case with the conventional transformer serves 90 MW at load 5, with 42 MW of utilization of line 3-5, and 48 MW of utilization in the transformer. This improvement in asset utilization is summarized in Table 18.



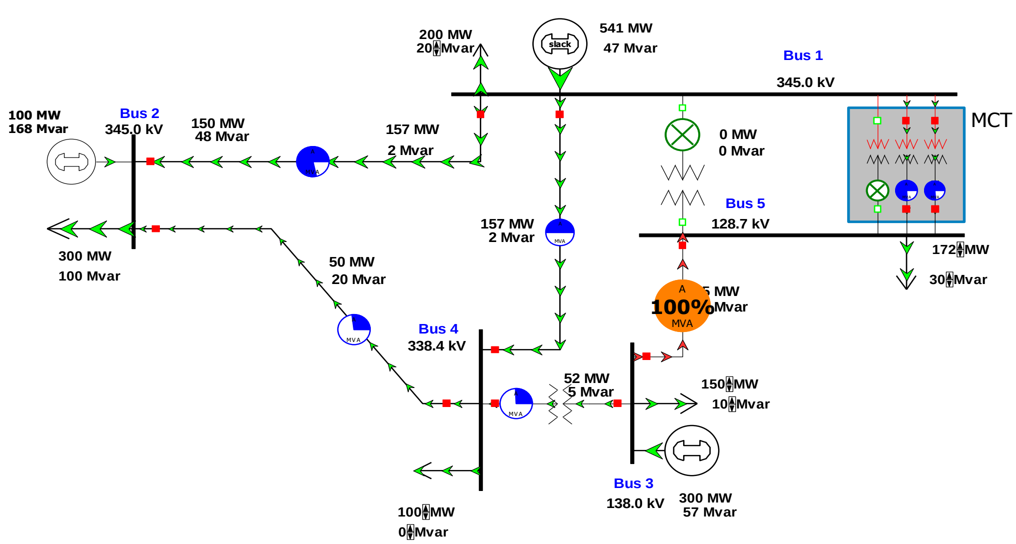


Figure 41: Maximum loading with Outage of the MCT

Table 18: Asset Utilization assuming Maximum Loadability and N-1 Security

Quantity	Reference Case	MCT Case
Load served at Bus 5 (MW)	90	160
Line 3-5 Flow (MW)	42	89
Transformer Flow (MW)	48	71

Reduction or Delay of Required Transmission Investment

As a result of increased asset utilization, a utility would expect to delay or reduce investment in transmission that would otherwise be needed. In Figure 41, we showed how MCT increased the transfer capability by simulating an increase in the load at bus 5 from 90 to 160 MW, where one line became congested. If we assume a 7% increase per year in demand for the load at bus 5, a line expansion will not be needed until 8.5 years in the future.

<u>Reduced Impact of Cyber-Attack</u>

Consider Figure 42, which illustrates the real-time control cyber layer for our sample system. The control center has dedicated lines or channels to the RTUs at each substation. Usually, the transformer instrumentation connects the transformer controls to the RTU ports, e.g., the RTU can control the transformer, including its terminal circuit breakers. In the case of the MCT, it is expected that the each MCT module will be a stand-alone device, with a separate controller for each device. Each MCT controller is connected to the RTU. MCTs also communicate with each other for coordination and consistency. For instance, regulation of voltage must take place in a coordinate manner.

The fact that each MCT has its own controller provides one additional cyber-step or barrier for potential attackers. If an attacker's objective is to control the MCT, it not only has to get to the RTU, but also infiltrate the MCT controller.

In the case the attacker gains access to the MCT controller, the most damage that it can do is disconnect (or in the worst case) one module. This action has, as pointed out, less impact than the outage of a conventional transformer. The attacker would have to gain access to the three MCTs simultaneously in order to effect the same level of disruption impact compared to the conventional transformer. Even if all the MCTs are damaged, their replacement will take place faster compared to conventional transformer. This discussion supports the notion of higher resilience of the system in face of cyber-attack.

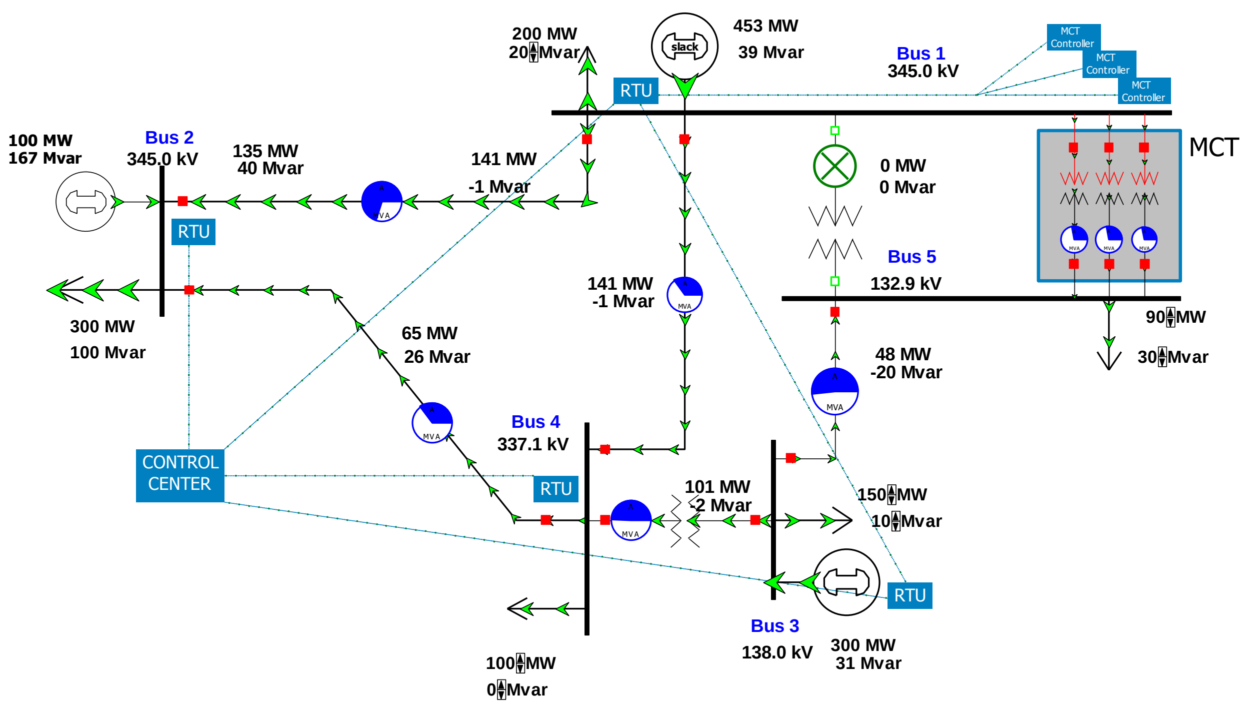


Figure 42: Reference System Cyber-Layer

Reduced Risk in Financial Transmission Rights (FTR) Mechanisms

Given the MCT capability to inject voltages, it can affect the distribution of flows and hence congestion. IN addition, the N-1 enhancement due to the presence of the MCT can further mitigate congestion in the system. Physical bilateral contracts play an important role in the efficient functioning of re-structured power markets and utility interconnection contracts in regulated environments. Generators and load-serving entities voluntary self-select into a negotiation process to mitigate price volatility. Because physical bilateral contracts obligate self-generation and self-consumption of the contract amount, participants must weigh the benefits and costs of trading off between the bilateral and pool markets. Additionally, the delivery of power through the transmission network during periods of congestion results in volatile congestion charges that diminish the value of a forward contract.

The value of a contract is assumed to be a function of the contract amount of electricity, the contract's constant dollar per megawatt-hour price, and uncertain nodal prices and congestion charges. However, the optimal expected contract value depends on only its ability to hedge against volatile pool market prices. This has important implications for power market operators when technologies that can reduce congestion such as MCT are available.

Consider the case in Figure 43 below where the Load at bus 3 wants to purchase 100MW of power from Generator at bus 4 at 10$/MWh (at the incremental cost of the generator at bus 4). In order to hedge against high LMPs, it also purchases 100MW worth of Financial Transmission Rights (FTR). The market clearing condition is shown in the figure below on the left, where the LMP at bus 3 is $13.2/MWh. Settlement requires Load 3 to pay 100 x 13.2 = $1,320 to the market. The market pays 100 x 10 = $1,000 to Generator 4. Due to the purchased FTR, Load 3 receives 100 x (13.2-10) = $320. In this manner, Load 3 has effectively traded 100MW at $10/MWh. The FTR cost is usually sunk and determined through an auction. Let us assume that the auction valuation was at 20% of the expected $320 FTR revenue. This means that having the FTR hedging costs the Load 3 $64.

Let us now consider an injection of 0.22pu reactance with the MCT in lines 1-3, which results in the LMP at bus 3 being equal to $12.4/MWh. While the contract settlement would result in effective trading of 100MW at $10/MWh, Load 3 has valuated the FTR too high: it has paid $64 for the FTR, while the actual valuation would have been 20% x 100 x (12.4-10) = $48. This example illustrates that:

a) Market participants should incorporate the effect of MCT in risk management strategies.

b) That the transmission providers can obtain addition revenues by strategically operating MCT.

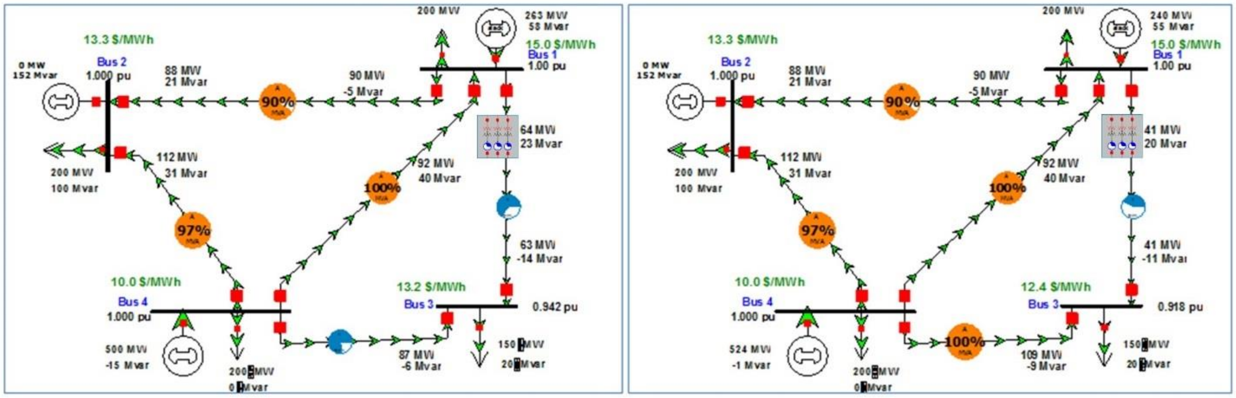


Figure 43: Reduction of Risk in FTR. Left: System LMPs and settlement without MCT. Right: Change on LMP prices with MCT and reduced price in FTR valuation.

4.17.6 Control Applications

Enhanced Voltage Regulation

The voltage injection capability of the MCT provides a flexible and powerful mechanism to regulate voltage, with the following advantages.

a) Increased range for voltage control

b) Continuous, power-electronics based control, as opposed to mechanical element control.

c) Possibility to add voltage injection to mechanical tap actions.

d) Enhanced control for post-contingency events.

3.3.2: Phase Balancing

Because MCT devices allow each phase to be controlled independently, there is an opportunity to correct for inherent imbalances in the power system. Such imbalances have been reported to be as large as 10% in transmission systems. A number of anomalies, such as increased power losses, inaccurate state estimation results, and ill-tripping of protective relays, have been traced to the existence of power flow imbalances. Furthermore, if the imbalanced line appears as congested in applications such as SCED, an error in the congested line can significantly affect the magnitude of transfers. The MCT could contribute to balancing the phase by slightly adjusting the voltage injections in each phase.

Enhanced Control of Loop Flows

Loop flows are a significant problem in bulk transmission systems. Two control areas that implement power transactions can inadvertently introduce loop flows in several of the neighboring areas. Due to the spatial nature of injections and extractions of power in meshed systems, loops flows may appear even when all control areas have zero net exports. MCT devices would provide a mechanism to limit and control loop flows. This is illustrated in the figure below, which shows a 7-bus, 3-area reference system. The figures on the left correspond to the bus diagram, and the figures on the right to the area diagram, where the loop flow is easier to visualize. Figure 44 shows the normal operation of the system with a MCT bypassed device. We note that there is a 40MW loop flow in the counter-clockwise direction Top->Left->Right. Figure 45 shows a MCT applied in line 5-7 with +0.2 pu reactance change. The control of the MCT results in a reduction of the loop flows to about 16MW.

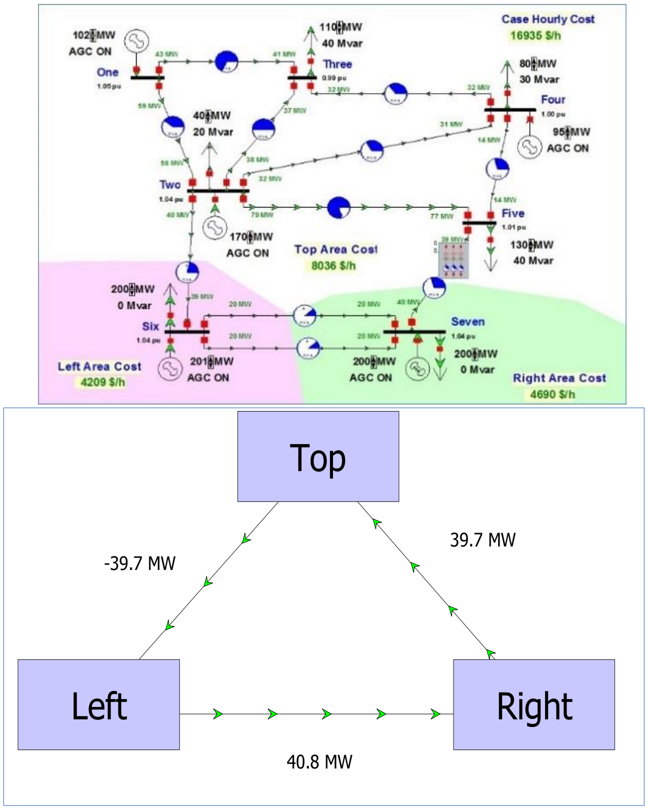


Figure 44: Loop flow control. 40MW loop flow without MCT

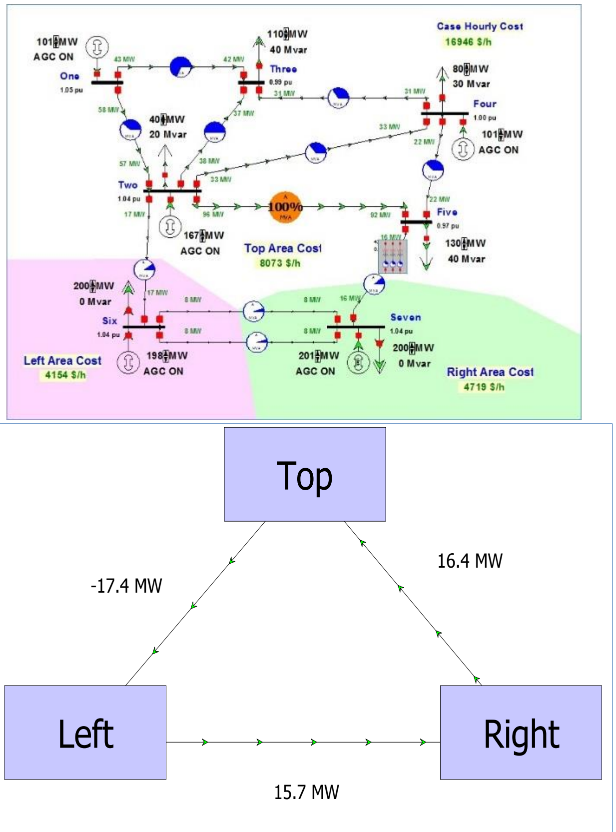


Figure 45: Loop flow reduced to 16MW by controlling a MCT.

<u>Increased Margin to Voltage Collapse</u>

Voltage collapse is a system-wide phenomenon, which arises when power transfers encounter a saddle node bifurcation or limit-induced bifurcation. Highly loaded systems, in particular while under severe contingency conditions, tend to exhibit a decreased margin to voltage collapse. The margin to voltage collapse is determined by running a continuation power flow or by sequentially increasing the transfer parameter in the transfer direction until no AC power flow solution can be obtained. The value of transmission component reactances as well as voltage regulation play a big role in the margin to voltage collapse. In particular, altering the voltage phasor injection of a MCT module could impact voltage collapse.

As an example, consider the 5-bus reference case. If the load at bus 5 is increased starting from 110MW, with the corresponding increase of generation at the slack bus 1, there will be a point where the power system reaches voltage collapse (the power flow Jacobian encounters a saddle node bifurcation). For the reference under an outage of the conventional transformer, this occurs when the load at bus 5 is equal to 348MW. With the MCTs, for an outage of a single MCT, the point of voltage collapse increases to 382 MW of load at bus 5.

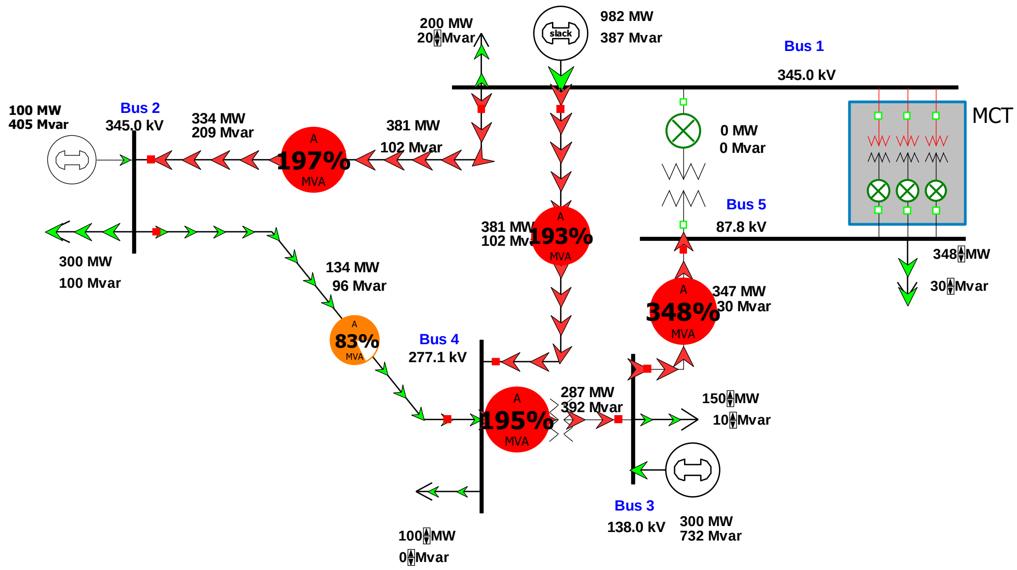


Figure 46: Margin to Voltage Collapse for the Reference Case during an outage of the conventional transformer. Collapse occurs when the Load at bus 5 is equal to 348MW.

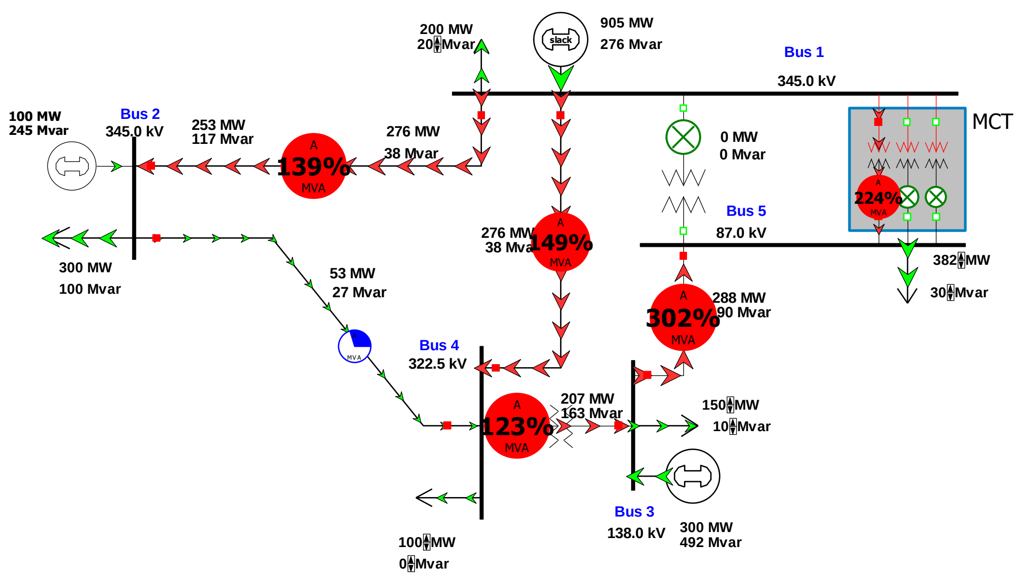


Figure 47: Margin to Voltage Collapse for the MCT case under an outage of one MCT module. Voltage collapse occurs when the Load at bus 5 is 382MW.

4.17.7 Enhanced Transient Stability Response

Power transfers are limited by thermal limits of transmission lines, low or high bus voltages, margin to voltage collapse, and transient stability limits. Transient stability is the ability of the system generators to remain in synchronism following a fault and corresponding fault clearing actions. Given a constant fault clearing time, the system is more likely to lose synchronism for more loaded transmission lines. Hence changing the reactances and the flows of power can enhance transient stability. This means that either the system has more loaded transmission elements with comparable transient behavior, or it has enhanced transient behavior (remain in synchronism for longer fault-clearing times) at the same level of loading. This is illustrated in Figure 48. The simulation uses the 5-bus reference case. The generators are modeled using round rotor generator models with standard parameter values. The figure on the left corresponds to the case without MCT. The figure shows loss of synchronism after a solid 3-phase balanced fault at bus 1 under an outage of the conventional transformer. The response of the system shows that the generators remain in synchronism for the same fault under an outage of a single MCT.

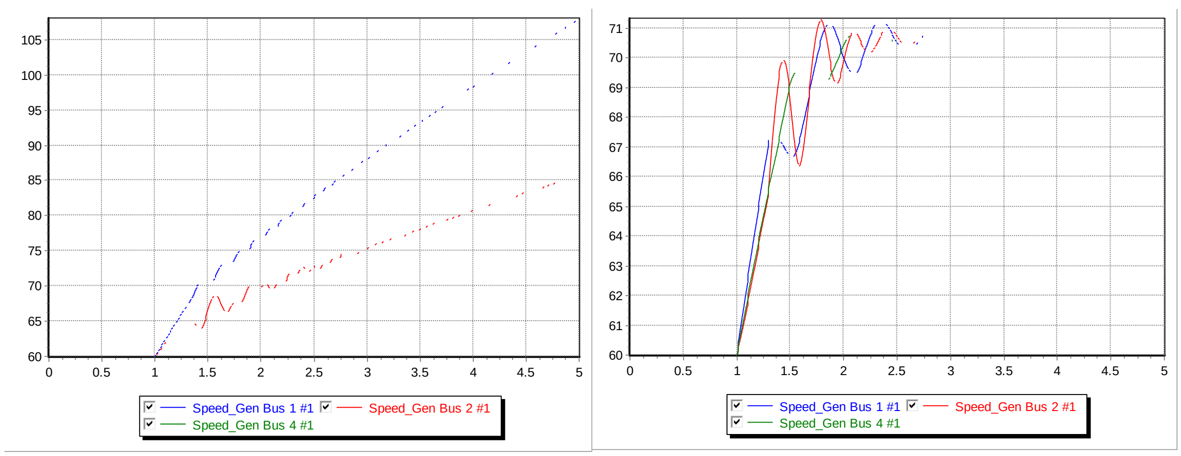


Figure 48: Enhanced Transient Stability Response with MCT

4.17.8 Locational Marginal Price (LMP) De-Localization

Nodal pricing is the standard electricity pricing method in power systems operating under market discipline (about half of wholesale systems in the United States). When there is a flow constrained transmission element, LMPs become localized with the higher price appearing at the receiving end of the constraint. If MCT are installed in the system, a significant portion of grid congested paths could be removed hence de-localizing the prices. Or, higher levels of power transfer could be allowed at the same price differential. Reduced congestion prices or higher transfers for a given congestion price represent significant surplus benefits and increased market efficiency. In particular, since MCT has better N-1 security, it is expected that the SCOPF or SCED will provide better results (more levelized prices, lower congestion prices, and lower over system operating cost). With less congestion the gradient of energy prices reduces and energy prices become less a function of physical location in the power system. This has multiple economic advantages such as reducing overall system operation cost, improving market efficiency, reducing market power, and promoting fair competition. This is illustrated in the Figure below using the reference case, which shows an LMP contouring visualization.

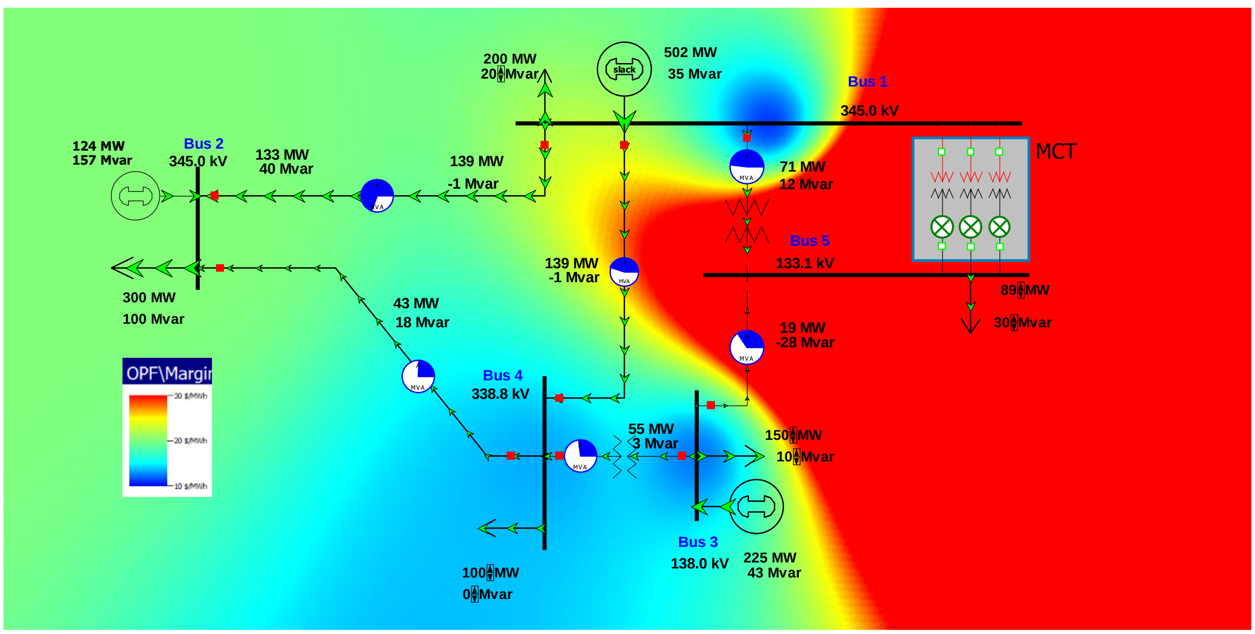


Figure 49: Case without MCT: LMPs and high LMP and contouring gradient

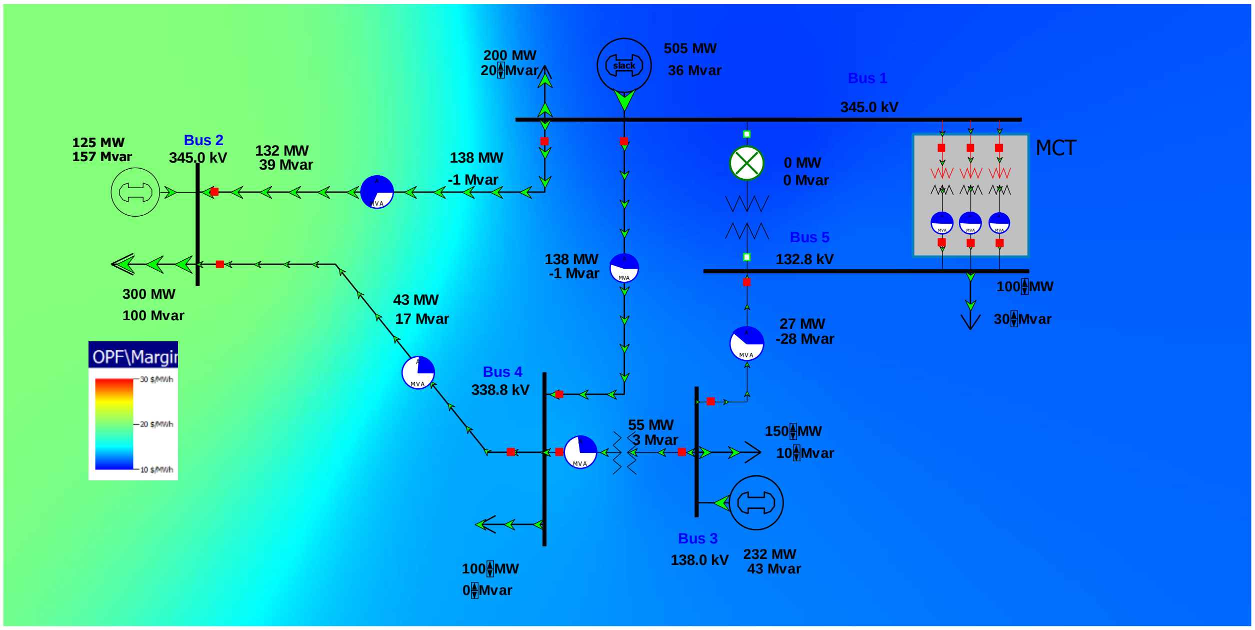


Figure 50: Smoother SCOPF LMP contouring due the presence of the MCT.

4.18 Small Case Proof of Concept

4.18.1 Small Case Selection

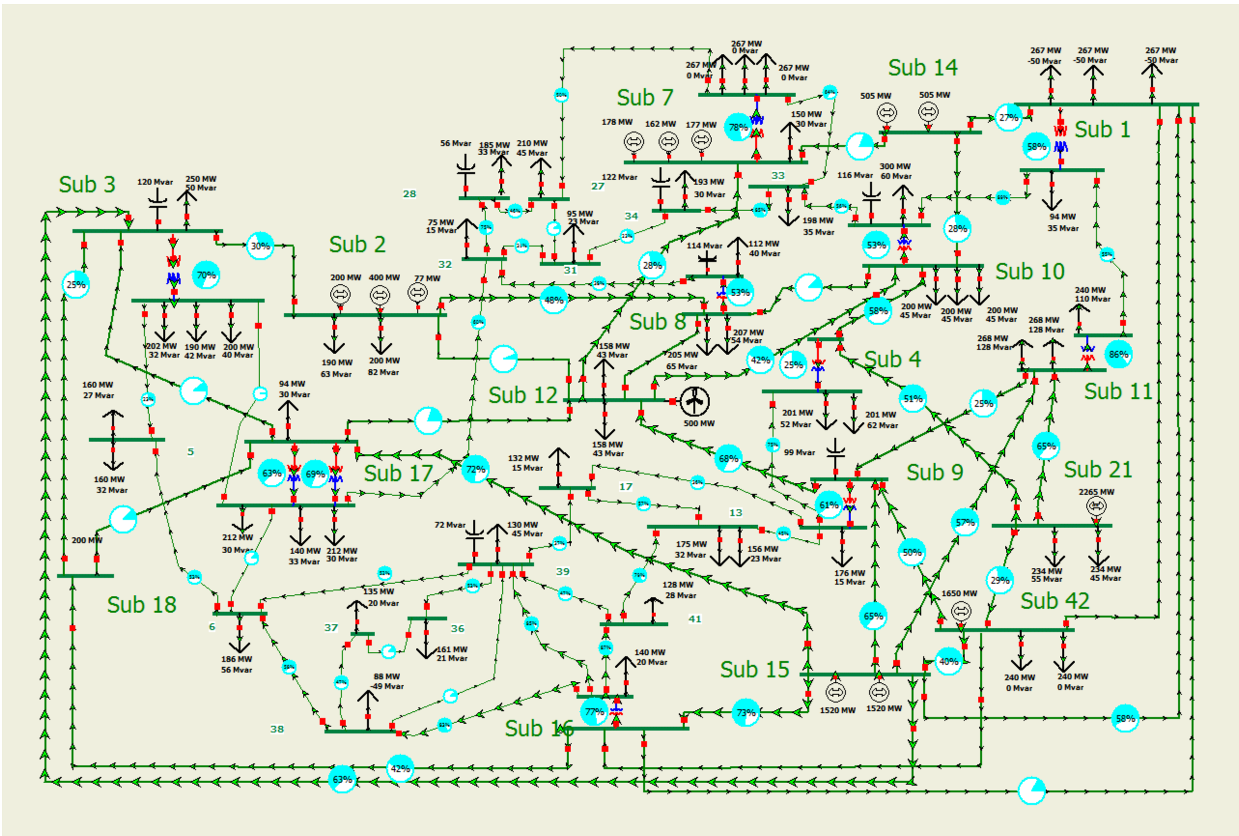


Figure 51 Small Case Baseline Operation

4.18.2 Baseline Contingency Simulation

Transformer Outage	Violations	Max %	AMWCO Baseline
T_000019-000026C1	9	255.2	1680.645
T_000008-000011C1	6	285.4	742.082
T_000035-000040C1	6	146	378.535
T_000021-000030C1	2	163.9	157.414
T_000020-000029C1	2	133.3	92.284
T_000009-000012C1	1	115	52.468
T_000003-000014C1	2	110.6	26.781
T_000004-000016C1	2	101.9	12.907
T_000024-000010C1	1	106.7	8.688

T_000004-000016C2	1	101.9	2.441
T_000007-000025C1	0	0	0
System AMWCO			3154.24

4.18.3 Impact of Modular Transformers

N-1 contingency of transformer 19-26 (worst contingency).

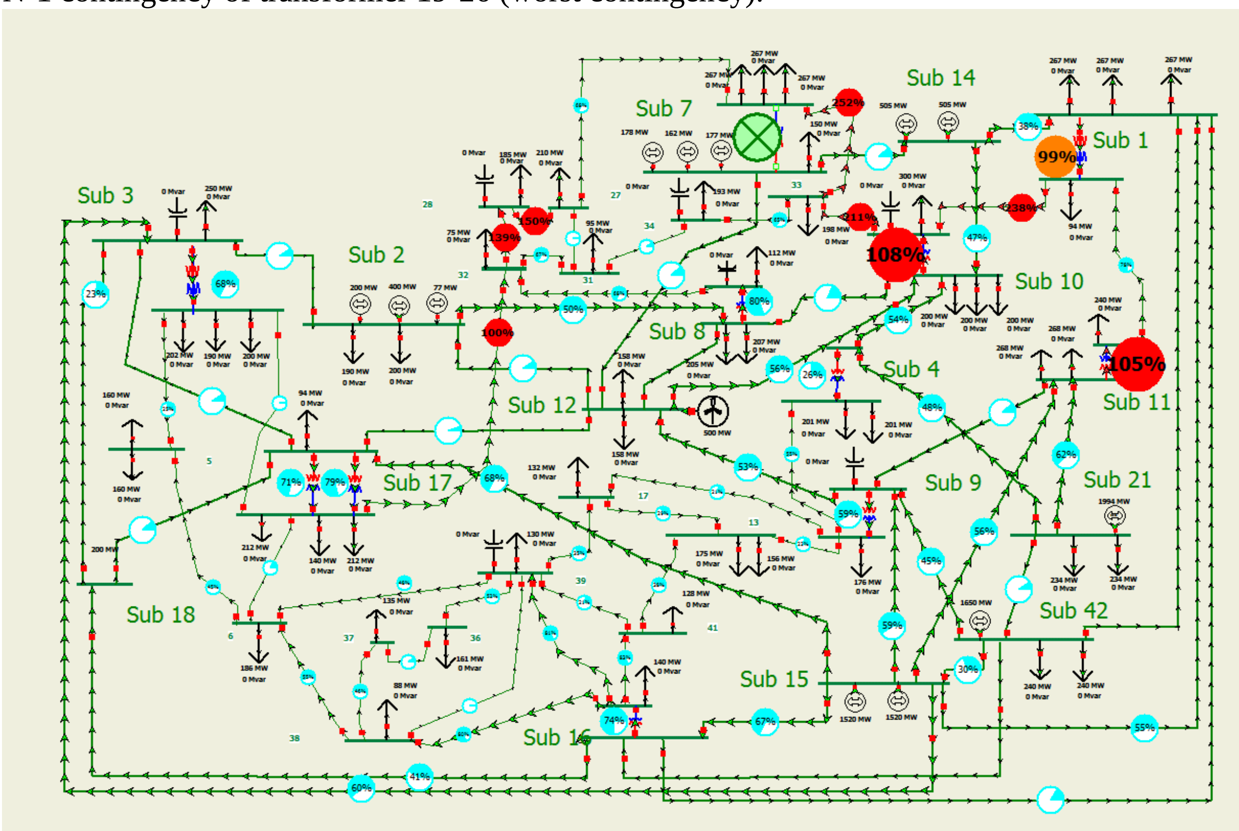


Figure 52 Contingency Analysis for the worst-contingency.

Contingency Label	Viols.	Max %	AMWCO Post worst CTG	Viols.	Max %	AMWCO N-1/3
T_000019-000026C1	9	251.9	1598.177	0		0
T_000008-000011C1	14	284.4	2327.796	4	283.8	677.293
T_000035-000040C1	14	255.7	1989.514	5	138.6	252.979
T_000021-000030C1	11	454.2	2834.681	2	152.7	150.668

T_000020-000029C1	8	278.6	2242.141	1	129.8	74.604
T_000009-000012C1	10	252.1	1635.163	1	114.9	52.16
T_000003-000014C1	8	252.1	1633.002	1	102.9	3.79
T_000004-000016C1	10	254.1	1755.979	1	102.5	15.274
T_000024-000010C1	9	244.1	1832.296	0		0
T_000004-000016C2	10	254.5	1731.955	0		0
T_000007-000025C1	10	246.8	1718.082	0		0
Sys			21298.786			1226.768

4.19 Resilience Analysis

4.19.1 Methodology

We have previously described the definitions and metrics associated with system resilience and determined the loss of load and the AMWCO as metrics for the intensity of the disruption. This, combined with the duration of the disruption provide the means to evaluate resilience given the evolution of the state of the power system.

Simulations are required in order to determine the loss of load or the AMWCO. The simulation has various considerations that must be addressed:

a) Disturbance modeling
b) System dispatch and operation
c) Characteristics of the modular transformer
d) Control devices in the system
e) Modular transformer controls, and
f) Optimal replacement and restoration decisions

We discuss these aspects below.

Disturbance Modeling

According to IEEE, any examination of emergency spare transformer strategies must include an assessment of the possible threats to the transformers. It is important to recognize that although some *High Impact Low Frequency* (HILF) events have never occurred in a given system or in any system, their probability cannot be assumed to be zero. Hence, a broad spectrum of potential scenarios is important to consider as possible causes and mechanism for the disturbance. Some of the mechanism may include:

- Long-term or permanent equipment failure
- Direct kinetic attack
- Cyber-physical attack
- Weather-related event

We simulate the disturbance for two cases: the baseline involving the conventional transformer, and the MCT case, involving the modular transformer. We will call these the *baseline simulation*, and the *MCT simulation*, respectively. The disturbance and occurs at a given instant (no duration), after which we would assume that the transformer becomes immediately inoperable. Both the baseline and the MCT simulations will consider a time range $[t_0, t_f]$. The disturbance occurs at time t_d s.t. $t_0 \le t_d < t_f$.

In the baseline simulation, it is assumed that the original transformer subject to the disturbance can be replaced in at time t_r. The original transformer is operable in the intervals $[t_0, t_d]$, and $[t_r, t_f]$ of the simulation, and it is not operable in the interval $[t_d, t_r]$.

In the MCT simulation, the original transformer is operable in the interval $[t_0, t_d]$, and is replaced by the MCT in a time $t_{MT} > t_d$. The MCT is operable in the interval $[t_{MT}, t_f]$

Dispatch and Operation

The second important consideration for both baseline and MCT simulations are the assumptions regarding the dispatch of the power system as time progresses. We will assume that the system is dispatched in real-time according to the established security constrained optimal power flow (SCOPF) policies. The SCOPF dispatch minimizes operational cost subject to what-if security constraints, which involves a large number of simulated outages, e.g. N-1 contingencies. This SCOPF optimization requires solving the following problem for each time period (e.g. one hour), where **S** is the vector of complex active power injections $S_i = P_i + jQ_i$ to the system buses.

$$
\begin{aligned}
&\min_{\mathbf{P}_G} \mathbf{c}^T \mathbf{P}_G \\
&\text{s.t.} \qquad \mathbf{S} - diag(\mathbf{V})\mathbf{Y}^* \mathbf{V}^* = 0 \\
&\qquad |S_e| \le S_e^{\max}, \quad \forall e \in Lines \\
&\qquad |S_{e,c}| \le S_e^{\max}, \quad \forall e \in Lines, \forall c \in CTGs \\
&\qquad P_g^{\min} \le P_g \le P_g^{\max}, \quad \forall g \in Gens \\
&\qquad \varphi_f^{\min} \le \varphi_f \le \varphi_f^{\max}, \quad \forall f \in Routers
\end{aligned}
$$

However, most of the US systems are not N-1 compliant, and in most cases of realistic operation, some contingencies are not considered, or are modeled together with post-contingency corrective actions. If such actions are not taken into account, the SCOPF can result in infeasible solutions where some contingency violations cannot be mitigated. Another option is to run the simulation as a series of power flows on participation factor control. We adopt this approach and calculate at each time point the level of security using N-1 contingencies without assumed post-contingency corrective actions. This allows determining an overall system security metric such as the AMWCO.

Characteristics of the Modular Transformer

We model the modular transformer replacing a transformer of a given MVA rating as 3 modular transformers identical to each other, with the same total equivalent resistance and reactance, connected in parallel between the terminals of the original transformer. When testing the modular transformer set, the AC power flow with the original transformer and that with the three modular transformers provides exactly the same solution.

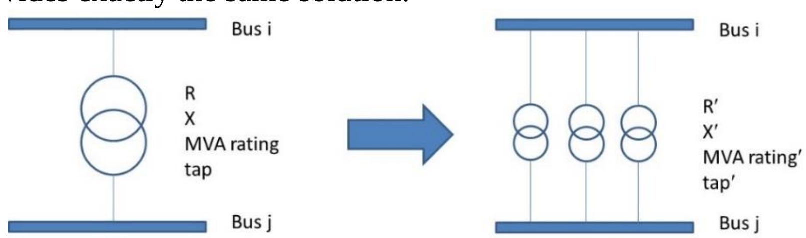


Figure 53: Original and Modular Transformer Topology for Large-Scale Simulations

Control Devices

The realistic operation of the system involves control actions by various devices including conventional (e.g. non-modular) LTC, generation exciters to regulate reactive power, capacitors and power electronic devices in automatic control. All these controls will be assumed to be on automatic control as determined by the development of the original system case (e.g. how the system is operated in reality).

Modular Transformer Controls

Two types of scenarios related to the modular transformer will be tested in the simulation:

a) Modular transformer with controls fixed.
b) Modular transformer in automatic control mode. The automatic control mode will assume a four-quadrant converter, and hence it models both active and reactive power voltage injections. For a large-case simulation, this is achieved by modeling the device as a power flow router in combination of a SVC in automatic regulation mode located at the regulating voltage bus of the original transformer. This is illustrated in the following table:

Table 19: Simple Conversion Between Original and MCT Parameters

Quantity	Original Transformer	Modular Transformer
Rating (MVA)	S	S/3
R (p.u)	R	3R
X (p.u)	X	3X
Voltage Control	LTC = ± 10% Nominal Volt	SVC = ± 3.33% Nominal Volt
Flow Control	None	Router: ± 0.033 S

Optimal Replacement and Restoration Decision-Making

During the power system event, the utility will make a set of decisions for the transformer considered part of the disruption. These decisions may include the following:

a) Repair of the transformer on site.
b) Replacement of the transformer by a conventional transformer
c) Replacement by a modular transformer
d) Construction and adaptation of infrastructure for new transformer

These set of decisions will involve considerations such as availability of spare transformers (conventional or modular), location of the warehouse and transportation route, cost of repair or replacement, and lead times. In the proposed resilience simulation, these will be inputs to the time step simulation. The various options and paths to restoration will be considered without using an integrated scheduling simulation option, but rather by analyzing the impact of various options proposed [15-18], and by assuming a given time where for a replacement with a conventional transformer (baseline simulation) and for the replacement with a modular transformer (MCT simulation).

4.19.2 Large Case Development

Synthetic Case

We will use large-scale, realistic, synthetic datasets for the analysis. This case represents the Texas bulk power system, at 69kV-and-above nodes as illustrated in Figure 54. The system involves 2007 buses and 2481 transmission lines and transformers. The total load is close to 50GW. The detailed parameters of this case developed in [19-21] are shows in Figure 55.

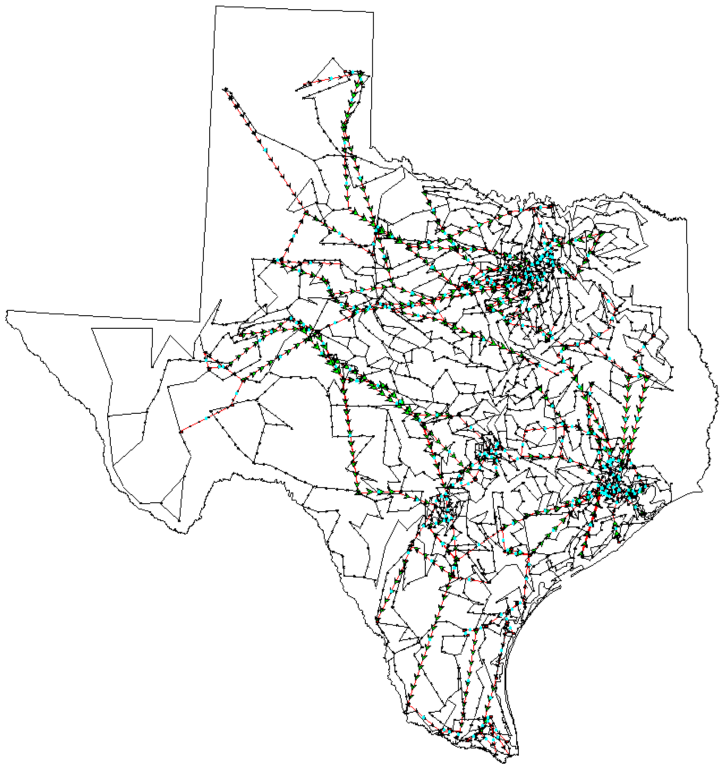
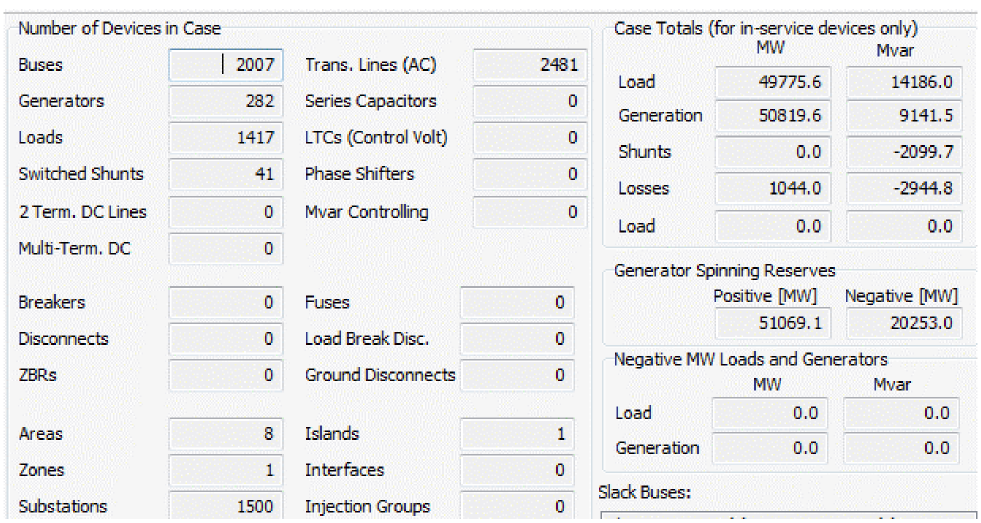


Figure 54: Large Scale Synthetic Test System



Number of Devices in Case

Buses	2007	Trans. Lines (AC)	2481
Generators	282	Series Capacitors	0
Loads	1417	LTCs (Control Volt)	0
Switched Shunts	41	Phase Shifters	0
2 Term. DC Lines	0	Mvar Controlling	0
Multi-Term. DC	0		
Breakers	0	Fuses	0
Disconnects	0	Load Break Disc.	0
ZBRs	0	Ground Disconnects	0
Areas	8	Islands	1
Zones	1	Interfaces	0
Substations	1500	Injection Groups	0

Case Totals (for in-service devices only)

	MW	Mvar
Load	49775.6	14186.0
Generation	50819.6	9141.5
Shunts	0.0	-2099.7
Losses	1044.0	-2944.8
Load	0.0	0.0

Generator Spinning Reserves

Positive [MW]	Negative [MW]
51069.1	20253.0

Negative MW Loads and Generators

	MW	Mvar
Load	0.0	0.0
Generation	0.0	0.0

Slack Buses:

Figure 55: Summary Parameters of Texas Synthetic Case

Base Case Analysis

Prior to conducting simulations with the synthetic case, it is necessary to explore several relevant quantities and metrics of the system. These include:

a) Voltage Profile: it was determined that the voltage magnitude levels for the system are adequate and provide the necessary heterogeneity for the system of this size.

b) Branch Limits: once a base case power flow solution is obtained, the limit monitoring settings of the various elements are explored and compared with the obtained AC power flows. For this system, the maximum normal overload was about 83%, and the loading in the set of branches had the appropriate distribution for peak summer condition.

c) Severe Outages: A N-1 contingency analysis was developed on the case to determine the structure of the contingency violations (what types of elements present violations) as well as the initial number of violations. As a byproduct of the contingency analysis, the base case AMWCO was determined for each element and for each contingency. In this manner week elements and several outages were identified and ranked. Figure 56 presents the ordered severe contingencies in the system as measured by the individual contingency AMWCO. The Figure shows a typical trend for bulk power system or severe contingencies rapidly decreasing in the value of AMWCO and then a long distribution tail. The top severe contingencies corresponded to line outages, while some transformer records appeared in the 10-20 most severe outages range.

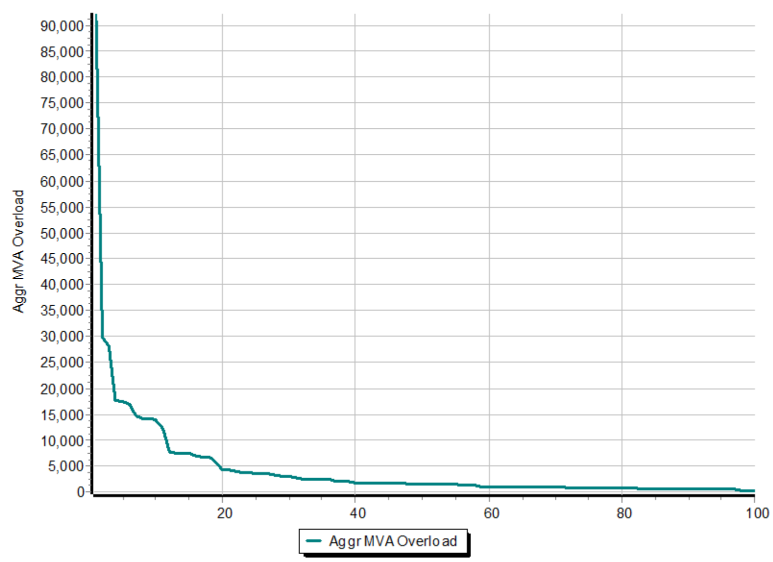


Figure 56: AMWCO of Top 100 most severe contingencies

d) Week Elements: In the same manner, the week elements are identified as those that exhibited the highest number and intensity of contingency thermal limit violations. The week elements are presented on Figure 57.

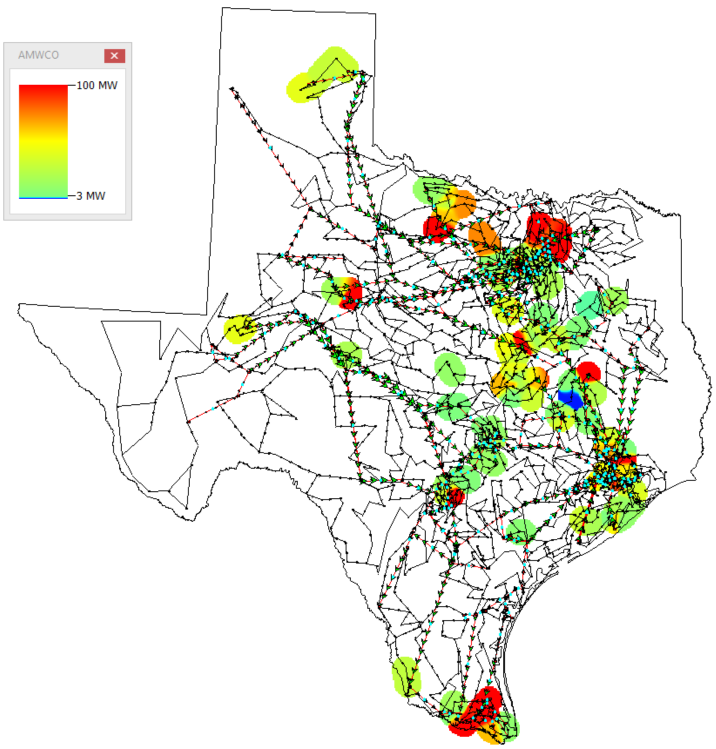


Figure 57: Contouring Visualization of Weak Elements in the System

e) Transformer Outages: We are interested in the performance of transformer outages and their impact in the system considering transformer replacement. Table 20 presents the most severe transformer outages in the system with the corresponding AMWCO metric. These are elements that if outaged, they would cause a significant amount of thermal overload in all the other elements in the system (lines and transformers).

Table 20 Most Severe Transformer Overloads

Label	Violations	AMWCO	Max Branch %
T_000688-001927C1	1	5296.3	153
T_000552-001937C1	3	4811.9	132.4

T_000277-001916C1	1	4800.4	148
T_000982-001961C1	2	4436.8	130.4
T_000627-001988C1	1	1291.7	112.9
T_001676-001788C1	2	1095	110.9
T_000035-001920C1	1	903.6	109
T_000990-001979C1	1	250.8	102.5

f) Demand Modeling: A bulk level demand modeling was obtained from ERCOT [21] and applied to the eight control areas modeled in the system. The area MW levels for one day are illustrated in Figure 58, and the geographic structure of the control areas in the system is illustrated in Figure 59.

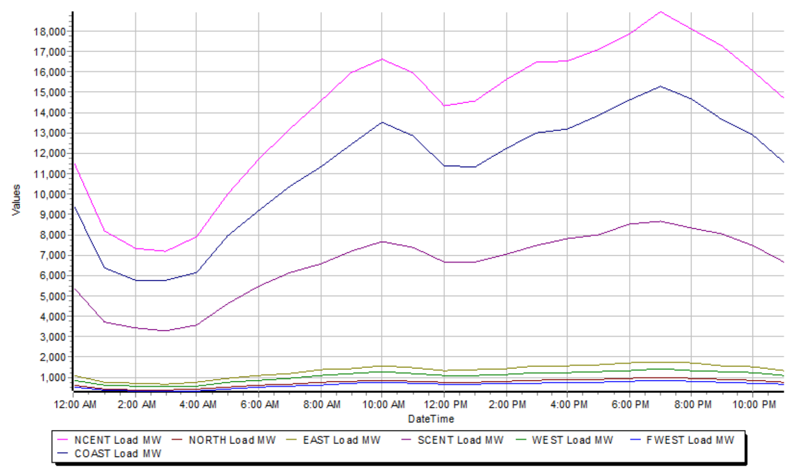


Figure 58: Area Total Demand in MW.

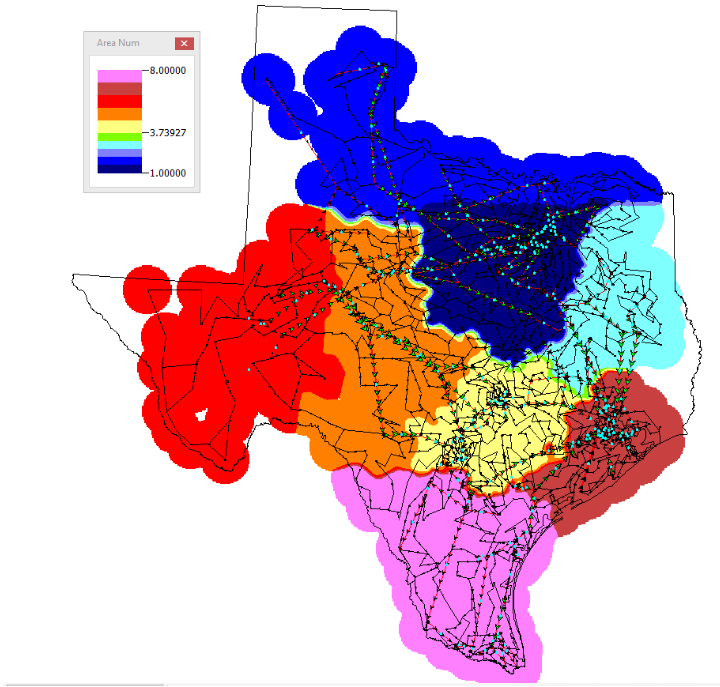


Figure 59: Geographic Distribution of Control Areas

4.19.3 Time Simulation with MCT Controls Fixed

Simulation Settings

The previous consideration and assumptions were utilized to set up the baseline and MCT simulations with controls fixed, as follows:

Base Case Definition:
Texas 2016 Summer Peak Case
2007 buses
3043 branches
3043 contingencies
8 areas

Time Step Simulation
Area interchange enforced

Generator participation factors proportional to maximum capacity
Participation factor power flow
24 hours Simulation
547 N-1 transformer contingencies
Demands according to ERCOT model

<u>AMWCO Evolution in Base Case</u>

Figure 60 presents the AMWCO by control area for the 24 hours simulation. The Figure illustrates the expected behavior that the insecurity metric becomes amplified during the peak hours of the day, e.g. the variance of the AMWCO values in time is increased to that of the demand curves in Figure 58.

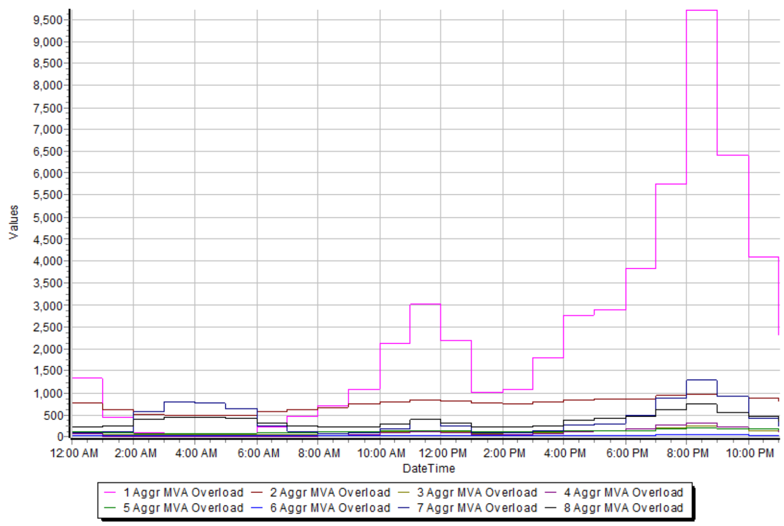


Figure 60: Control Area baseline AMWCO

<u>MCT Simulation</u>

The most severe AMWCO outage occurred for transformer T_000688-001927C1 with an AMWCO = 5296 MW overload. An outage of this transformer was assumed and replaced with modular transformers. Figure 61 illustrates the modeling of the original transformer as well as the configuration of the replacing MCTs. The connected buses are also presented to illustrate the topology of the region around the transformer.

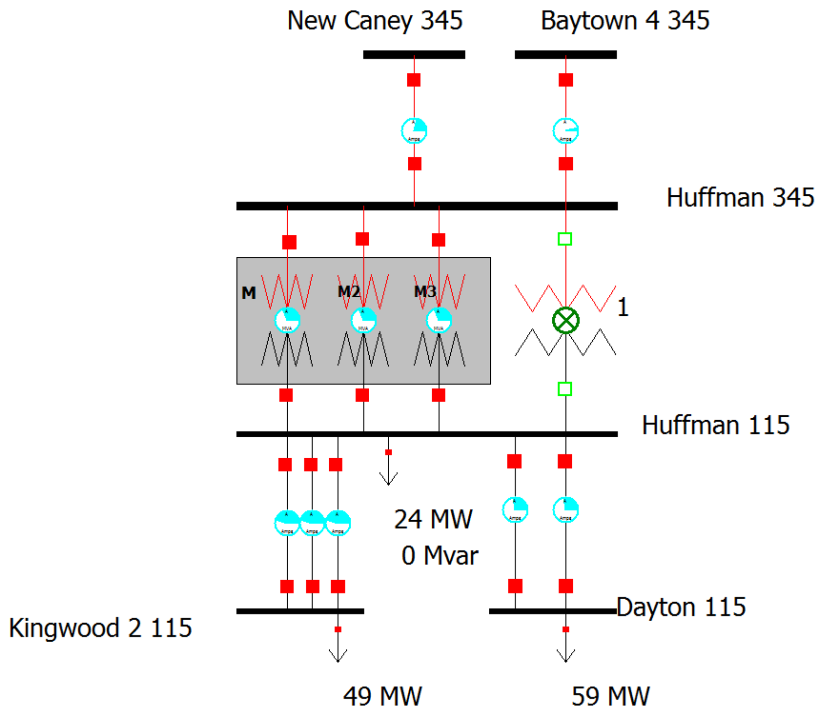


Figure 61: Bus View of Original Transformer

For the baseline simulation, the MCT transformers are disconnected while the original transformer is shown. For the MCT simulation, the MCT transformers are connected, while the original transformer is disconnected. The AC power flow solutions for these two configurations area identical.

Regarding the contingency modeling, the N-1 contingency analysis in the baseline involves simulating the outage of the original transformer. In the MCT simulation 3 contingencies of each of the modular transformers are simulated. During each of the contingencies involving one MCT, the other 2 MCTs remain connected and operational, e.g. there is flow across these two MCTs.

Figures 62 and 63 present AMWCO for the baseline and for the MCT simulations based on 24 hours N-1 operation. The Figures shows a significant reduction in the area level AMWCO by the introduction of the MCTs to replace the transformer that caused the most severe outage.

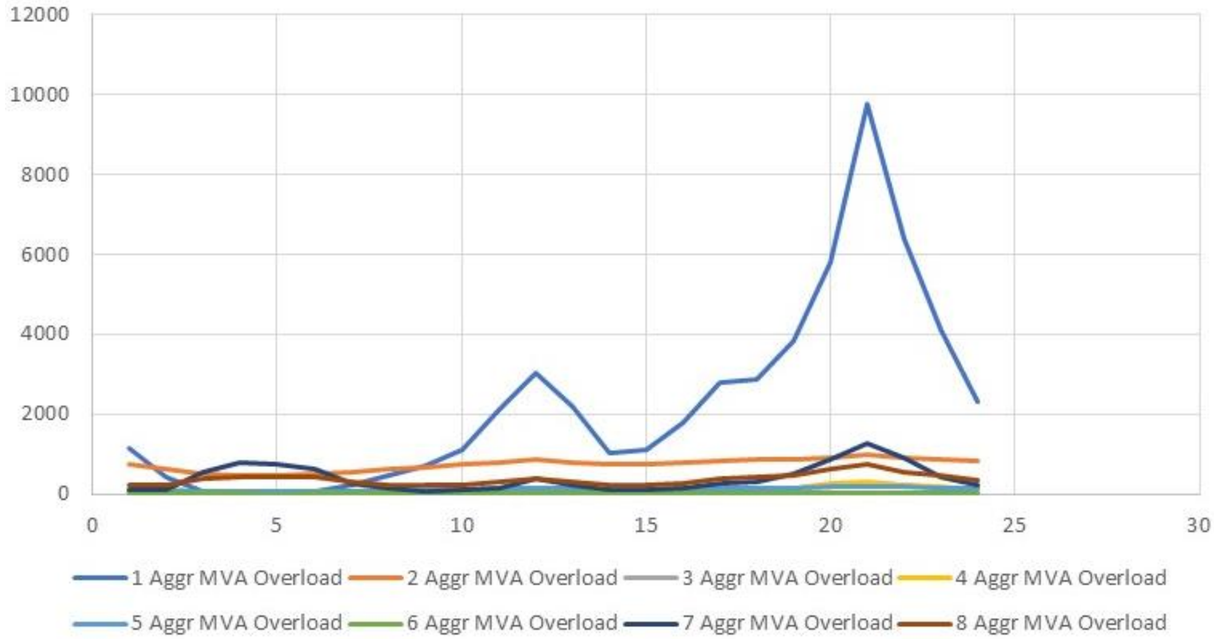


Figure 62: Control Area AMWCO for Baseline Simulation

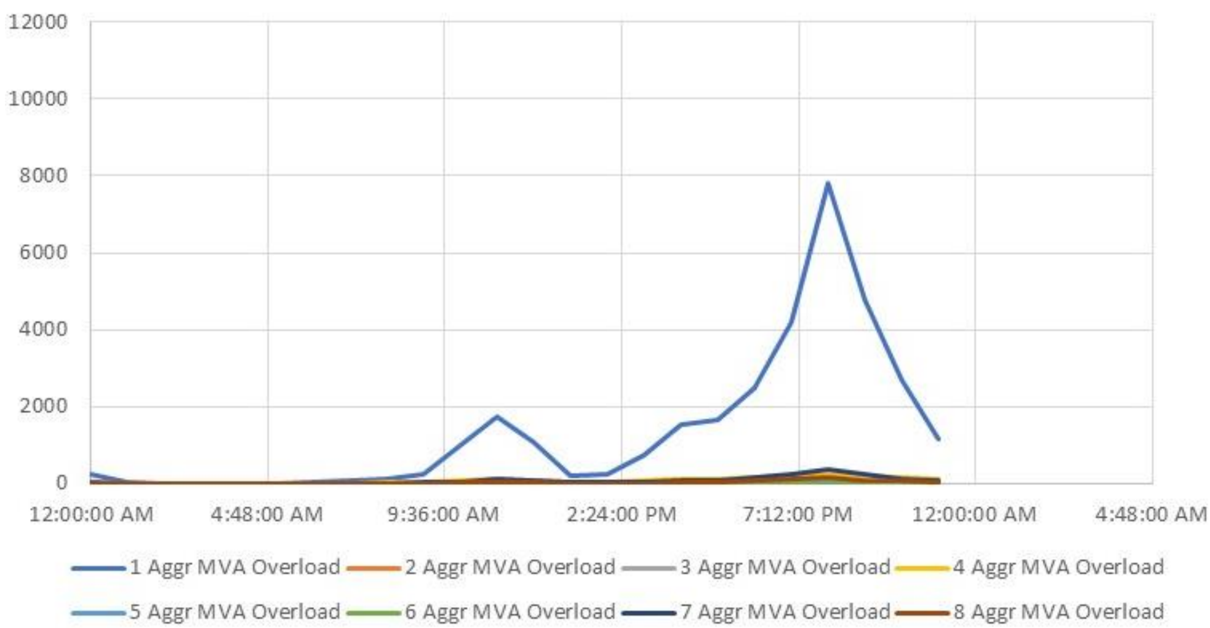


Figure 63: Control Area AMWCO for MCT Simulation

Figure 64 presents the system level AMWCO (the sum of all the control area AMWCO) for the baseline and MCT simulations, again presenting a significant reduction.

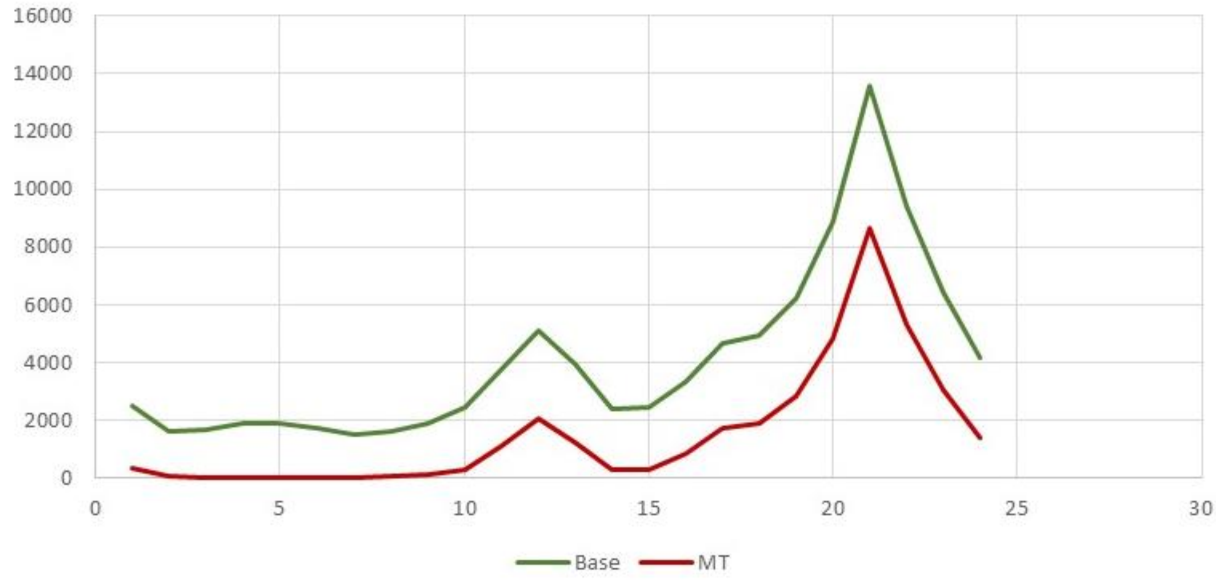


Figure 64: System Area AMWCO for Baseline and MCT Simulation

We see from Figures 62 and 63, that the AMWCO reduction is not necessarily uniform across the various control areas. Figure 65 illustrates the percentage reduction of AMWCO as a function of the control area and of time. A value of 100 means that the AMWCO was reduced to zero during the MCT simulation compared to baseline for a given hour and control area.

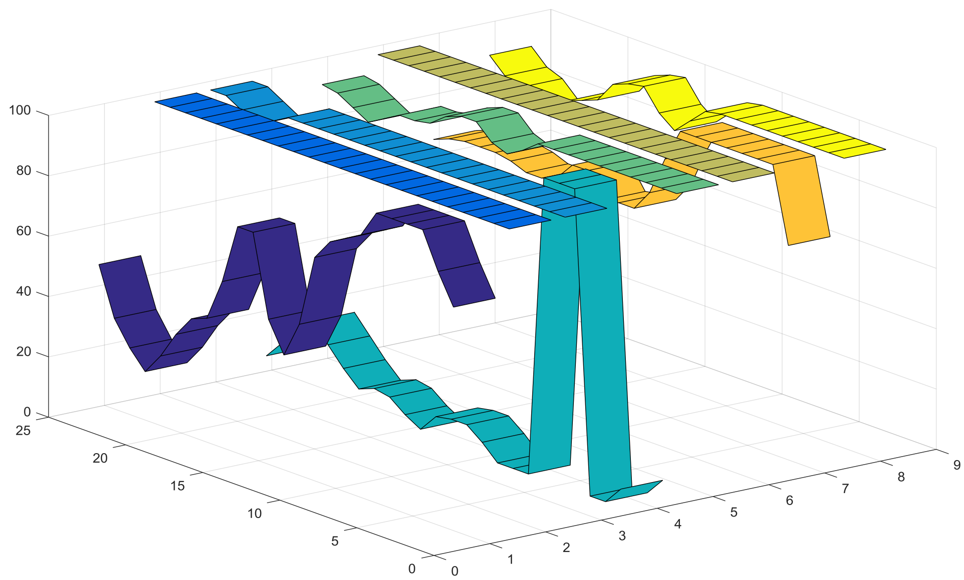


Figure 65: Percent Reduction of AMWCO for each hour and for each control area.

Finally, the total AMWCO for the day was determined by adding the AMWCO for the system for each hour, and for each area. The baseline and MW results are presented in Table 21. We see that the AMWCO reduction was of about 63%, considering N-1 transformer contingencies.

Table 21 Daily System AMWCO for Baseline and MCT Simulations

Case	Base	MCT
System AMWCO	98,417.94	36,600.13 (37.2%)

Resilience Improvement

The reduction in insecurity as measured by AMWCO has been studied for one day in the realistic synthetic Texas system. It shows about a 63% reduction. During contingency analysis, the thermal overloads in the various elements of the system are identified and tabulated. Contingency analysis though does not provide a measure of the ultimate impact of the overloads. For instance, an overloaded transmission line cannot remain in that condition for a long time. Either corrective action would take place in the order or seconds or minutes (depending on the overload level), or the line would be disconnected by protection relays. This disconnection of the line represents a second outage (N-2), which in turn can cause further problems ultimately leading to the loss of load. In meshed systems (such as most bulk power system), the N-1 contingency simulation does not result in explicit disconnection of load, unless the outages element is radial to the load. This happens more at the sub-transmission level. In the Texas case, the full N-1 contingency created just a few explicit loss of load. In conclusion, the AMWCO is able to capture the aggregate effect of thermal overload and loss of load, since the thermal violations imply a probability of losing load. Given that a simulation with explicit probabilities of loss of load will entail detailed modeling of the protection systems, we alter our resilience equation to include only the AWMCO metric:

$$\mathrm{R}(t) = \frac{1}{\int_{t=t_d}^{t_{restoration}} Sys_{AMWCO}(\mathbf{x}^0(t), S_C, S_E)dt}$$

where $t_{restoration} = t_r$ for the baseline simulation, and $t_{restoration} = t_{MT}$ for the MCT simulation.

The sum of the system AMWCO for the various hours effectively computes the integral in the previous equation. As an example, let us assume that the MCTs can be replaced in 0.25 of the time that the replacement of the original transformer, e.g.

$$\frac{t_d - t_{MT}}{t_d - t_r} = 0.25$$

Thus, with the assumption, if the value of the integral for the baseline simulation is I_{base}, the value of the integral for the MCT case is $I_{MT} = 0.25 \times 0.372 \times I_{base} = 0.093 I_{base}$, e.g. less than 10% of insecurity. The resilience will improve as the inverse of that factor, e.g. an improvement in resilience close to one order of magnitude.

4.20 Economic Analysis

4.20.1 Methodology

For economic analysis, a procedure needs to be developed for justifying the MCT transformer. In the case of the MCT there are benefits that can be quantified and monetized, and others that are more difficult such as voltage. Not only the ability to control voltage depends on a variety of factors such the location, type of exiting LTCs, proximity to generators with voltage regulating capability, settings of devices on automatic voltage regulation, etc., but also voltage is more difficult to monetize since most existing tools do not consider voltage as an optimization variable, but rather a constraint. There are also indirect benefits for services and applications such as those described in the portfolio of applications, which included: additional grid flexibility to incorporate variable renewables, enhanced response to transients, reduced congestions, etc.

In this analysis we are interested in monetization of the benefits. A way to do that is to base the methodology on comparison of the system operational cost under various scenarios. If the deployment of the MCT results in a better operation of the grid, this must be reflected in its operating cost. Fr this purpose, we compare the scenarios listed in Table 6.1:

Table 22 Scenarios Considered

Scenario Name	Description
BASELINE	System Baseline Considers the system in normal operation, dispatched according to an Optimal Power Flow (OPF). This dispatch does not consider contingencies (security), outages of any kind, or replacement of the transformer.
X-OUT	Conventional Transformer Out of Service Considers the operation of the system with the conventional transformer out of service, and the system under OPF dispatch.
MCT	Modular Controllable Transformer in Service Considers the operation of the system where a modular controllable transformer has replaced the conventional transformer, and the system is being dispatch using the OPF.
SEC_BASE	Secure System Baseline

	In this scenario, N-1 contingencies are considered in the dispatch. The system is operated under a Security-Constrained Optimal Power Flow (SCOPF).
SEC_XOUT	<u>Secure with Conventional Transformer Out</u> In this scenario the conventional transformer is out of service, and the system is operated observing N-1 contingencies in SCOPF
SEC_MCT	<u>Secure with Modular Controllable Transformer in Service</u> In this case the modular controllable transformer has replaced the conventional transformer, and the system is dispatched observing N-1 contingencies according to the SCOPF.

We interpolate the results on the operational cost for the various scenarios to determine a value per MVA of installed MCT capacity. We then compare this with expected cost installing an MCT. We further apply a simulated disturbance and replacement scenario in order to evaluate the benefits associated with speed of replacement enabled by the MCT.

4.20.2 <u>Large Case Development for Economic Simulation</u>

<u>Synthetic Case</u>

We use large-scale, realistic, synthetic datasets for the analysis. This case represents the Texas bulk power system, at 69kV-and-above nodes. The system involves 2000 buses and 2481 transmission lines and transformers. The total peak load of this case is close to 67GW. The detailed parameters of this case are developed in. This system has been populated with cost data suitable for the types of generators present in the Texas system. Figure 66 shows the results of the Optimal Power Flow (OPF) and contouring of the corresponding bus locational marginal prices.

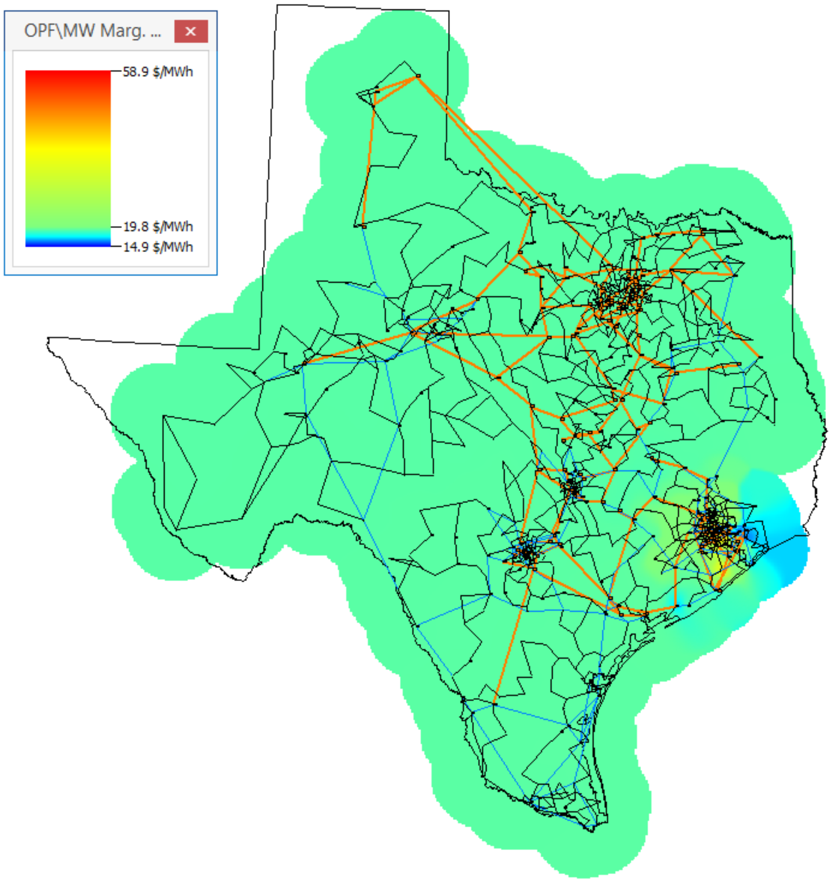


Figure 66: Large Scale Synthetic Test System for Economic Analysis

Contingency analysis was developed for this case and a set of transformers candidate for replacement was determined. We selected a 200MVA the transformer with the characteristics shown in Figure 6.2.

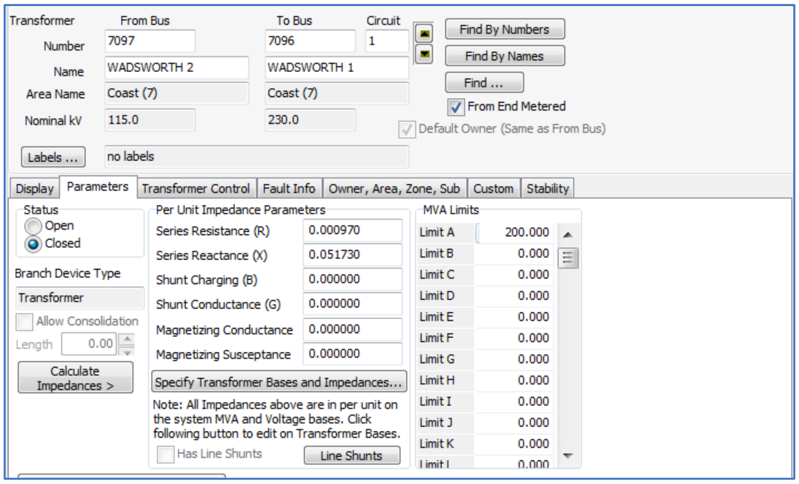


Figure 67: Summary Parameters of Texas Synthetic Case

The corresponding MCT is set up in parallel to the conventional transformer. During the simulation only one of the two transformers (or none) are used at a time in order to realize the scenarios listed on Table 6.1. The reactance, resistance, and limits of the MCT are derived from this transformer.

<u>Case Settings</u>

The N-1 contingency analysis for this system results in a significant number of contingency violations under both line and transformer outages. In other words, this case, as many US realistic cases is not N-1 compliant for summer peak conditions. This occurred for both the based power flow solution, and the base OPF solution. While a feasible OPF solution can be found for the system, the solution for the SCOPF is non-feasible.

Analysis of the contingency violations shows several lines beyond their thermal limits. The SCOPF was not able to identify controls that could mitigate those overloads under contingency conditions, resulting in unenforceable contingency violations. In those cases, the limits of the elements involved (about 8 branches) were increased in the range from 1 to 15% until the SCOPF can be solved under N-1 for the peak condition. This procedure is consistent with the specification of emergency limits on those lines.

The SCOPF algorithm finds the minimum cost of operating the system, subject to N-1 contingency violation constraints. When the SCOPF Linear Programming step is completed, the system is re-dispatched to a new operating state. The new operating state may result in new contingency violations being created. Thus, more than one outer loop is required. A maximum of 5 outer loop iterations was specified. This was sufficient to converge all the SCOPF runs while processing all the contingency violations.

4.20.3 Simulation Results

Impact on System Operating Costs

Simulations were conducted for each one of the scenarios, for 24 hours for a typical load curve at the system level using ERCOT data. This simulation allows determining various effects of loading of the system under normal operation and contingency violation constraints, as well as determining the total operating costs under OPF and SCOPF dispatch. The total operating cost per hour is presented on Table 23 and Table 24 presents the differences in operating cost with respect to the BASELINE scenario.

Table 23: Texas Hourly Load and Total Operating Costs

	Load MW	Cost $/Hr	Cost $/Hr	Cost $/Hr	Cost $/hr	Cost $/hr	Cost $/hr
Time	**MW**	**BASELINE**	**XOUT**	**MCT**	**SEC_BASE**	**SEC_XOUT**	**SEC_MCT**
12:00:00 AM	43621.00	824590.50	833982.75	827940.88	852172.72	867188.10	855441.97
1:00:00 AM	30199.16	648244.38	648244.38	648244.38	649117.92	649406.54	649117.92
2:00:00 AM	26843.69	626224.94	626224.94	626224.94	626966.83	627211.95	626966.83
3:00:00 AM	26843.70	626224.94	626224.94	626224.94	626966.83	627211.95	626966.83
4:00:00 AM	28856.97	639005.81	639005.81	639005.81	639826.60	640097.79	639826.60
5:00:00 AM	36910.09	714321.13	723341.69	717746.88	761497.52	784999.89	764840.45
6:00:00 AM	43621.00	824588.38	833989.75	827944.00	852172.84	867192.77	855291.99
7:00:00 AM	48318.66	899199.31	909320.00	902805.56	930335.73	940714.36	933695.44
8:00:00 AM	53687.38	989409.69	1001054.19	993383.81	993236.10	1000959.66	996844.42
9:00:00 AM	58385.06	1072456.00	1084779.38	1076820.13	1076291.49	1086767.49	1080587.71
10:00:00 AM	61740.49	1132921.88	1145632.00	1137409.50	1143165.10	1155051.10	1147318.25
11:00:00 AM	59056.12	1084483.63	1096868.38	1088870.00	1088464.01	1098049.13	1092740.04
12:00:00 PM	53687.39	989408.19	1001050.69	993382.06	993236.87	1000959.31	997201.08
1:00:00 PM	53687.39	989409.94	1001050.69	993382.19	993236.53	1000959.72	996998.74
2:00:00 PM	57042.85	1048503.88	1060694.50	1052826.63	1052396.12	1064384.99	1056490.06
3:00:00 PM	60398.33	1108634.63	1121151.13	1113059.25	1114201.35	1123940.35	1118201.18
4:00:00 PM	61740.50	1132922.00	1145630.13	1137409.63	1143165.25	1155051.25	1147440.98
5:00:00 PM	63753.78	1170275.75	1183473.38	1174922.50	1192523.36	1205461.49	1196759.52

6:00:00 PM	67109.24	1236680.75	1250882.00	1241646.75	1262205.80	1271088.55	1266990.42
7:00:00 PM	70464.70	1307167.13	1325036.88	1312837.50	1315077.97	1317724.47	1320746.15
8:00:00 PM	67109.25	1236678.50	1250882.13	1241645.63	1262210.76	1270657.39	1266762.42
9:00:00 PM	63753.77	1170275.63	1183473.25	1174922.38	1192429.78	1205160.15	1196816.32
10:00:00 PM	60398.32	1108634.25	1121150.63	1113059.00	1114201.37	1123940.50	1118344.22
11:00:00 PM	53687.38	989398.88	1001029.56	993372.94	993246.27	1000982.02	997112.41

Table 24: Texas Difference in Total Operating Costs with Respect to Baseline

	Load MW	**Cost $/Hr**	**Cost $/Hr**	**Cost $/Hr**	**Cost $/hr**	**Cost $/hr**	**Cost $/hr**
Time	**MW**	**BASELINE**	**XOUT**	**MCT**	**SEC_BASE**	**SEC_XOUT**	**SEC_MCT**
12:00:00 AM	43621.00	0.00	9392.25	3350.38	27582.22	42597.60	30851.47
1:00:00 AM	30199.16	0.00	0.00	0.00	873.54	1162.16	873.54
2:00:00 AM	26843.69	0.00	0.00	0.00	741.89	987.01	741.89
3:00:00 AM	26843.70	0.00	0.00	0.00	741.89	987.01	741.89
4:00:00 AM	28856.97	0.00	0.00	0.00	820.79	1091.98	820.79
5:00:00 AM	36910.09	0.00	9020.56	3425.75	47176.39	70678.76	50519.32
6:00:00 AM	43621.00	0.00	9401.37	3355.62	27584.46	42604.39	30703.61
7:00:00 AM	48318.66	0.00	10120.69	3606.25	31136.42	41515.05	34496.13
8:00:00 AM	53687.38	0.00	11644.50	3974.12	3826.41	11549.97	7434.73
9:00:00 AM	58385.06	0.00	12323.38	4364.13	3835.49	14311.49	8131.71
10:00:00 AM	61740.49	0.00	12710.12	4487.62	10243.22	22129.22	14396.37
11:00:00 AM	59056.12	0.00	12384.75	4386.37	3980.38	13565.50	8256.41
12:00:00 PM	53687.39	0.00	11642.50	3973.87	3828.68	11551.12	7792.89
1:00:00 PM	53687.39	0.00	11640.75	3972.25	3826.59	11549.78	7588.80
2:00:00 PM	57042.85	0.00	12190.62	4322.75	3892.24	15881.11	7986.18
3:00:00 PM	60398.33	0.00	12516.50	4424.62	5566.72	15305.72	9566.55
4:00:00 PM	61740.50	0.00	12708.13	4487.63	10243.25	22129.25	14518.98

5:00:00 PM	63753.78	0.00	13197.63	4646.75	22247.61	35185.74	26483.77
6:00:00 PM	67109.24	0.00	14201.25	4966.00	25525.05	34407.80	30309.67
7:00:00 PM	70464.70	0.00	17869.75	5670.37	7910.84	10557.34	13579.02
8:00:00 PM	67109.25	0.00	14203.63	4967.13	25532.26	33978.89	30083.92
9:00:00 PM	63753.77	0.00	13197.62	4646.75	22154.15	34884.52	26540.69
10:00:00 PM	60398.32	0.00	12516.38	4424.75	5567.12	15306.25	9709.97
11:00:00 PM	53687.38	0.00	11630.68	3974.06	3847.39	11583.14	7713.53
Total			**$244,513**	**$85,427**	**$298,685**	**$515,500**	**$379,841**

We note that the differences in operating costs are relatively consistent:

1. The N-1 SCOPF dispatch is more expensive compared to the OPF dispatch.

2. Outage of the conventional transformer increases the operating cost both with respect to baseline and with respect to secure baseline.

3. The cost with the MCT is lower compared to the cost under an outage of the conventional transformer.

With respect to total daily operating cost, Figure 68 presents the total cost for the various scenarios considered (last row on Table 24). The performance of the MCT compared to the conventional transformer under outage conditions is notorious. Furthermore, we note that the difference in operating costs between MCT and XOUT under OPF ($159k per day) is comparable but a little bit larger than the corresponding difference between SEC_MCT and SEC_XOUT under SCOPF ($135k per day).

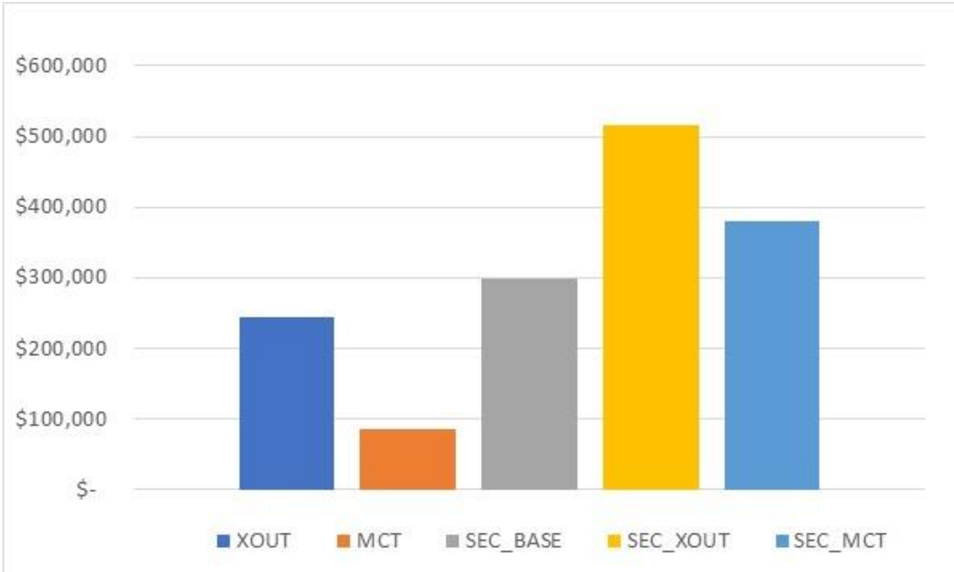


Figure 68: Comparison of daily cost difference with respect to baseline.

Cost of Insecurity and Monetization of Resilience

The disturbance modeling definitions can also be applied to a model of resilience monetization. The disturbance occurs at a given instant (no duration), after which we would assume that the conventional transformer becomes immediately inoperable. Both the baseline and the MCT economic simulations will consider a time range $[t_0, t_f]$. The disturbance occurs at time t_d s.t. $t_0 \le t_d < t_f$.

For the case of economic simulation, we can alter our equation of resilience to include as a metric of insecurity the difference in total system operating between a conventional transformer outage and the baseline, or the MCT transformer outage and the baseline:

$$\mathrm{R}(t) = \frac{1}{\int_{t=t_d}^{t_{restoration}} INS(\mathbf{x}^0(t), S_C, S_E)\,dt}$$

Where:

$$INS^{XOUT} = \frac{\left(SCOPF_{DAILY\_COST}^{XOUT} - SCOPF_{DAILY\_COST}^{SEC-BASE}\right)}{MVArating} = \$1,084.08 \,/\, \text{day-MVA}$$

$$INS^{MCT} = \frac{\left(SCOPF_{DAILY\_COST}^{MCT} - SCOPF_{DAILY\_COST}^{SEC-BASE}\right)}{MVArating} = \$405.78 \,/\, \text{day-MVA} = 0.374 INS^{XOUT}$$

We note that the insecurity with the MCT transformer is about 0.374 of the insecurity with the conventional transformer under SCOPF dispatch. In the simulation example, the reduction in total operating cost was achieved by replacing the conventional 200 MVA transformer with the MCTs.

Let us assume as in 5.3.4 that the MCTs can be replaced in 0.25 of the time that it would take to replace the conventional transformer, e.g.

$$\frac{t_d - t_{MT}}{t_d - t_r} = 0.25$$

With the assumption, if the value of the integral for the conventional transformer simulation is I_{base}, the value of the integral for the MCT case is:

$$I_{MCT} = 0.25 \times 0.374 \times I_{base} = 0.0935 I_{base} ,$$

e.g. the MCT case results in less than 10% of the insecurity of the conventional transformer. The resilience will improve as the inverse of that factor, e.g. an improvement in resilience close to one order of magnitude. We recall from Chapter 5, that we obtained a 10% relationship of MCT AMWCO compared to conventional transformer AMWCO.

It is surprising that this result of resilience analysis involving a cost metric is very similar compared to the improvement result we obtained using the AMWCO metric. This may be due to the fairly linear relation between loading and total operating cost as presented in Figure 69.

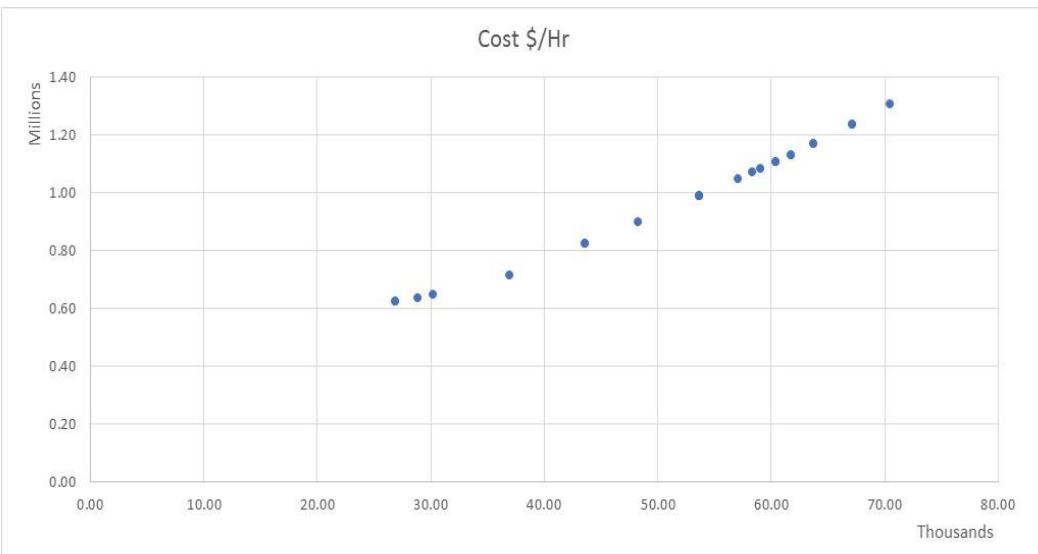


Figure 69: Total Operating Cost as a Function of System Load (MW)

Basic Cost Benefit Analysis

Let us consider the Texas case and a practical example of a transformer replacement where the conventional transformer takes 20 days to replace and the MCT 5 days. Let us also assume for simplicity that the transformer rating is 200MVA. The benefit with the MCT is the difference between the integrals I_{MCT} and I_{base} above, or 0.9065 of the difference if operational cost $SCOPF^{XOUT}_{DAILY\_COST}$ with respect to SEC_BASE multiplied by 20 days. This is equal to $3,930,584.

Opt.	Description	HV (KV)	LV (KV)	Cost ($/MVA)	Rating (MVA)	XFRM Cost ($)
1	112 MVA top rating (+10MVA converter)	115	46	$12,410.71	112	$1,390,000
2	60 MVA mobile with trailer (+two 5MVA converters)	115	46	$20,833.33	60	$1,250,000
3	60 MVA mobile w/o trailer (+two 5MVA converters)	115	46	$18,833.33	60	$1,130,000
4	66 MVA top rating (+two 5MVA converters)	115	46	$14,848.48	66	$980,000

Table 25: Estimated Costs of MCT Transformers

Table 25 presents estimated costs of MCT transformers. Expanding from this Table, one can estimate the cost of a 230-115KV transformer plus converter to be between $2 and $2.5 million. If the example disturbance occurs once in the 30-year lifetime of the equipment, the replacement is justified based only on the improvement in resilience as determined by decreased operational cost under secure dispatch.

We note that the 25% of replacement time for the MCT compared to the conventional transformer is conservative. We also note that MCT has several other benefits due to applications as listed earlier. Hence, more detailed analysis is required in order to fully capture all the potential value streams of the MCT.

In this work, MCTs were shown to be able to increase grid resiliency for a large-scale synthetic Texas test case over traditional bulk power transformers. We showed that a single MCT has a significant impact in reducing the AMWCO by continuing to provide transformer action during the event. Reasonable assumptions regarding the MCT transportation logistics and replacement logistics results in shorter duration disruption, which also increases system resilience. Future work includes simulating MCTs with enabled controls.

4.21 Modular Controllable Transformers: Regulatory and Economics Aspects Related to Grid Resiliency, Operations, and Planning

The deployment of Modular Controllable Transformers to replace conventional large power transformers in transmission lines is considered from regulatory and economic perspectives, and the advantages for both grid resiliency and improvement for grid operations are outlined.

LPTs (and transmission assets in general) at 100 kV or higher are considered part of the Bulk Electric System, along with its reliability constraints. MCTs utilization for the same nominal voltage range should then still be compliant the BES requirements, regardless on the power capacity of the single modules. In summary, the introduction of MCTs modules with smaller power doesn't change the BES classifications, that remains as that of the original LPT, and thus requires the same Reliability Standards compliance.

The NERC perspective on Critical Infrastructure protection is reviewed, in order to facilitate proper planning of MCTs deployment, thus avoiding the introduction of a novel technology in a highly critical environment.

Once the technology is mature, one advantage of the MCT utilization in the critical infrastructure is the possibility of reducing the number of required spares, if the control and modular features can be shown to be able to prevent instabilities, uncontrolled islanding, or cascading, even with less than 100% of functional units.

From a power electronics control perspective, the advantage of the MCT technology stems from the introduction of properly designed tertiary that may not be present (with the same required features) in conventional transformer units already installed.

The risks due to the increased MCTs complexity, as compared to conventional large power transformer can be mitigated in the design phase. This allows to assume that, for a given time interval, the probability of one failure of an LPT is close to that of one failure of one of the modules of an MCT, while all the other modules are fully operational. As it is shown, an important consequence of this assumption is the impact on improvement of the grid resilience.

In the context of grid operations, the relevance of MCTs in relation to expansion planning for transmission infrastructure, is also outlined, as it represents a potentially wide area of applications for MCTs beyond replacement of failed/aging units, and is in line with the grid modernization needs.

Scope

This section discusses the regulatory and economic aspects of the Modular Controllable Transformers (MCTs) implementation, in the context of improved grid resiliency and operations for near-future grid expansion.

It is acknowledged that the regulatory landscape presently provides relatively minor attention to newer technologies that can significantly impact the large power flows in the grid. A successful implementation, on a sufficiently large scale, of the MCT technology, may change this as new policies may be considered or developed.

Purpose

This analysis aims to establish a straightforward path towards testing and deployment of MCTs, so that design features and testing documentation can be set in place to minimize the effort from a regulatory compliance perspective.

An issue that is being considered is the relevance of MCTs in relation to expansion planning for transmission infrastructure, that represent a potentially much wider market for MCTs beyond replacement of failed/aging units.

MCTs Role in the Context of Grid Modernization

With the target of addressing resiliency improvement and more robust grid operations (in the context of expansion planning of the infrastructure) some specific modeling efforts are required to show the value of MCTs as an advantageous alternative to conventional transformers.

The proposed approach goes beyond the simple addition of Unified Power Flow Controllers (UPFCs) on the line: the justification of an integrated magnetics/power electronics design stems from the advantage of a properly designed tertiary that may not be present (with the same required features) in conventional transformer units already installed. Options are available also for sub-transmission and distribution applications: for smaller units the cost analysis will determine the minimal size where the MCTs still provide an advantage.

The risks due to the increased complexity of MCTs compared to conventional large power transformer can be mitigated, so that the MCTs will not be significantly more vulnerable than conventional units. This will consider MCTs protection against failure modes and threats (e.g. flood, lightning, EMP, cyber-physical) related the power electronics section, to ensure MCTs full functionality.

4.22 Regulatory Issues

4.22.1 Regulatory Analysis for Rollout of MCTs

Overview

With the legal authority granted by the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC) develops and enforces Reliability Standards for U.S. Bulk Power System[1] (BPS). For all users, owners, and operators of U.S. BPS, compliance with Reliability Standards developed by NERC is mandatory and enforceable.

Adoption of new technologies in the BPS may introduce changes to the system's status of reliability compliance and result in unexpected consequences. Therefore, before the rollout of a new power grid technology, such as the MCT, it is important to conduct an analysis to review the relevant regulatory compliance issues related to the adoption of the specific technology.

This section is intended to provide such a regulatory study for the rollout of MCTs. The modular design and flexible control features of MCTs allow for the application of replacing a large power transformer by multiple MCTs with smaller ratings. This type of replacement changes system configurations, and thus may affect the system of compliance to certain reliability requirements.

This analysis requires the knowledge of how the compliance system is structured under the NERC Reliability Standards framework. Therefore, the NERC Bulk Electric System[2] (BES) definition is selected as the starting point of the regulatory study because it is the foundation of the other reliability compliance requirements.

Besides reliability, the cyber-physical security compliance is another important aspect worth in-depth analysis. The most relevant set of standards regarding this aspect is the NERC Critical Infrastructure Protection (CIP), and it will be discussed in the following sections.

[1] By Federal Power Act (FPA). Section 215 – Bulk-Power System: (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability.
[2] Discussions on the relationship between BPS and BES can be found in FERC Order #693, March 2007

The NERC Bulk Electric System

The BES definition is developed by NERC to identify the BES Elements[3] in an accurate and consistent manner. Elements included in the BES should be compliant to the corresponding reliability standards[4]. BES definition consists of a core definition, five Inclusions, and four Exclusions. The structure of BES definition is illustrated in Fig. 70.

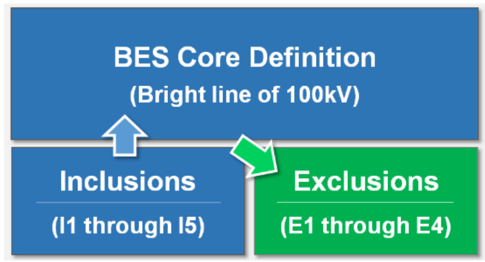


Figure 70. Illustration of BES definition structure

The core definition establishes a threshold of 100 kV as the overall demarcation point between BES and non-BES Elements, with Inclusions and Exclusions as summarized in Table 1.

Table 26 - Summary of NERC BES Inclusions and Exclusions

Inclusion	Exclusion
I1 – Transformers ○ **Primary and at least one secondary terminal at ≥100kV, unless excluded by E1 or E3** **I2 – Generating resources + step-up transformers (high side at ≥100kV)** ○ **Single unit rating ≥20MVA** ○ **Multiple units aggregated rating ≥75MVA** **I3 – Blackstart resources** ○ **Identified in Operator's restoration plan** **I4 – Dispersed generating resources with aggregated capacity ≥75MVA, both:** ○ **The individual resources** ○ **The system designed for delivering the capacity to a common point of connection at ≥100kV** **I5 – Static VAR sources/sinks** ○ **Connected at ≥100kV** ○ **Connected through a dedicated transformer with high side at ≥100kV, or included by I1** ○ **Unless excluded by E4**	**E1 – Radial systems (transmission Elements emanating from a single point of connection ≥100kV)** ○ Only serves loads ○ Only includes generating units not identified in I2, I3, or I4 and aggregated capacity ≤75MVA ○ Severe loads and includes generating units not identified in I2, I3, and I4 and aggregated non-retail generation ≤75MVA **E2 – Behind-meter generating units** ○ Net capacity provided to BES ≤75MVA **E3 – Local networks (LN)** ○ No generating resources identified by I2, I3, or I4, and aggregated non-retail generation ≤75MVA ○ With real power only flows into the network, not for transferring power originated outside through the LN ○ Not part of a Flowgate or transfer path **E4 – Dedicated VAR devices** ○ Installed for the sole benefit of a retail customer(s)

[3] By NERC Glossary of Terms: Elements are any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.
[4] For a complete list of the Mandatory Reliability Standards, see FERC Order #693, March 2007

According to the definition, "all transmission Elements operated at 100 kV or higher and real power and reactive power resources connected to 100 kV or higher" are in the BES, unless identified as one of the Exclusions. The Inclusions specify several categories of facilities and configurations that should be included in the BES.

Among the BES Inclusions and Exclusions, I1 is directly regarding transformers i.e., MCTs, and I2, E1, and E3 are also related. Four cases of applying I1 to transformers and operating configurations typically used in utility industry are depicted in Fig. 71. Based on the voltages on the primary and secondary windings, transformer A and B in Fig. 71 are included in BES, while C and D are not.

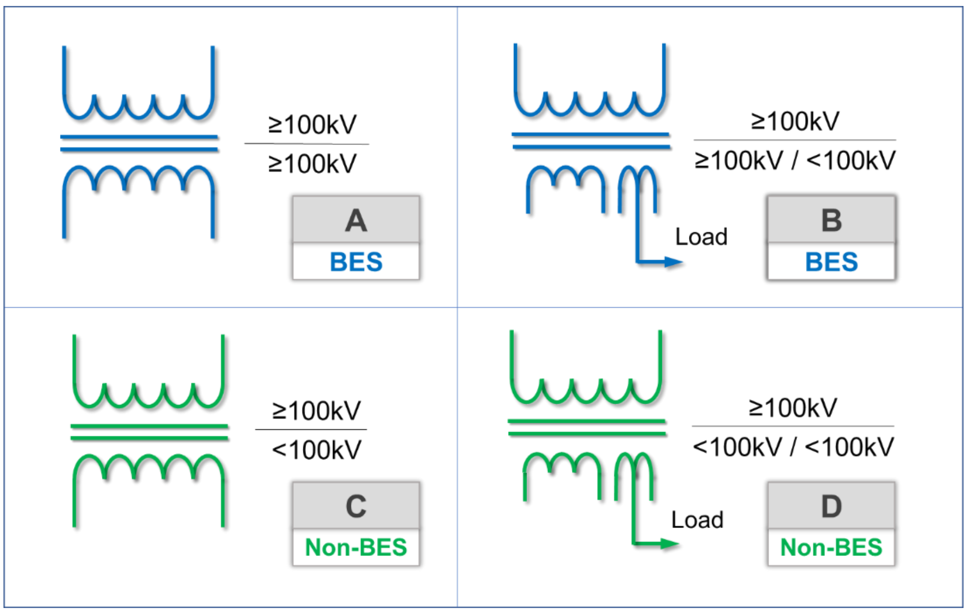


Figure 71 Application of I1 to four typical utility transformer configurations

The line voltages the transformer is connected to represent the key to determine whether or not it should be considered as part of the. The capacity of the transformer doesn't affect its BES classification.

For generator step-up (GSU) transformers, their BES classifications are determined based on the rating capacity of the generator (generator group) and the voltage level the high side of the transformers are connected to. Again, the capacity of the transformer is not a factor to its BES classification.

Radial systems and local networks, commonly used configurations in distribution grid, may be excluded from BES if they meet requirements of BES Exclusion E1 or E3. Transformers in those radial systems or local networks are thus non-BES Elements, even if their voltage connections meet the BES requirements.

When the BES classification of an Element changes (e.g. due to equipment upgrading/replacement, system re-configuration, etc.), the responsible entity is obligated to file a Self-determined Notification of BES inclusion or exclusion through the BES Notification and Exceptions Tool (BESNet). The Notifications are then reviewed by NERC.

Impact of Bulk Electric System Definition on MCT Rollouts

As discussed in the previous section, the BES classification of a transformer is determined solely by the voltage levels the transformer windings are connected to, the capacity does not play any role.

Thus, replacing a transformer originally identified as a BES Element by multiple small-rating MCTs does not exempt the replacement MCTs from the BES inclusion, i.e., the corresponding Reliability Standards compliance still apply, because the windings of the MCTs have to be connected to the same voltages as the replaced transformer.

The replacement MCTs should still be compliant with the same applicable Reliability Standards. If the replaced transformer is not included in the BES, then the MCTs won't be either. In summary, **the replacement of transformers with MCTs doesn't change the existing BES classifications, nor does it affect the Reliability Standards compliance.**

On the other hand, the BES definition does not require any additional regulatory steps to be taken if the purpose of the MCT deployment is to replace existing transformers. This is because the replacement process does not include changes of the existing BES classification.

If the purpose of the MCT deployment is not the replacement of an existing transformer, but to provide MCTs as new transformer installations, the responsible entities need to go through the BES analysis and notification process to identify the BES classification of the MCTs. However, this requirement is not related to the specific MCT technology, but applies for any type of transformers.

The radial systems and local networks identified by BES Exclusion E1 and E3 are not included in the BES, and thus MCT applications for those systems would also not be considered part of the BES, and not subjected to BES reliability compliance requirements. These two categories of configurations are usually seen in distribution grids. For these cases, an MCT rollout would then encounter reduced regulatory complexity and risks.

4.22.2 NERC Critical Infrastructure Protection and MCTs

General Guidelines

NERC Critical Infrastructure Protection (CIP) is a suite of standards designed to ensure the cyber and physical security of the assets required to reliably and securely operate North America's BES. Eleven of the twelve CIP standards concern themselves with cyber security (CIP-002 through 011, CIP-013); one concerns itself with physical security (CIP-014).

MCT features a power electronics based controller to enable various flexible control functions. How the control systems (controller, algorithm, communication, etc.) of MCTs are connected and used in the grid operation systems may vary between applications, but they all subject to cyber and physical security considerations and need to comply with relevant standards, such as NERC CIP. This subsection is to analyze the CIP standards that might be regarding MCT rollout and their potential impacts.

There is an economic driver for the industry to develop technologies that are less subject to regulatory constraints, on the other hand it is recognized that a placement in service of items in the grid that control a significant amount of power can affect large geographical areas and population segment, thus warranting energy security becoming the primary concern.

According to the NERC Glossary [NERC, 2018], "Critical Assets" [5] were defined as "Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System"[6].

While the NERC standards have changed some definitions, in general, the terminology "critical infrastructure" still refers to in which an asset is deployed in situations that can be summarized as follows:

- Large[7] control centers or backup control centers
- Transmission stations or substations that, if damaged, would cause instability, uncontrolled islanding, or cascading
- Single locations with active power resources of 1,500 MW or more.
- Single locations with reactive power resources of 1,000 MVAR or more.
- Any location or facility involved with automatic load shedding, Interconnection Reliability Operating Limits (IROLs), Special Protection Scheme (SPS) or Remedial Action Scheme (RAS).

[5] With the implementation of new CIP standards, the definition of "critical asset" was deemed "inactive" as of June 30, 2016.

[6] Bulk Electric System (BES): unless otherwise specified, all transmission elements operated at 100 kV or higher, and active and reactive power resources connected at 100 kV or higher.

[7] "Large" here summarizes a more specific definition given in the standard, Attachment 1

- Any other situation[8] where failure of the new technology puts an interconnection at risk.

This last item intends to include situations where engineering judgment and the principles of conservative design apply, i.e., the system planners will not put the interconnection at risk even if someone finds a “loophole” in the verbiage.

For assets considered part of the critical infrastructure, there is a requirement of have spares at hand, in order to be able to restore power quickly.

Even if the eventual goal is to use the MCT for critical infrastructure settings, from a new technology adoption perspective, deploying the early production units in non-critical settings will allow them to develop an empirical body of evidence of their effectiveness, reliability, and maintainability.

In regard to the identifications of substations that fall into the critical infrastructure category according to the CIP-014 criteria, it is important to observe that with an MCT implementation, it would be possible to show that a single module failure would not cause “instability, uncontrolled islanding, or cascading”, because the ability of utilizing the remaining modules and leveraging on the power control features.

This would then provide an advantage from the point of view of the required spares: in these conditions, in fact, only as many module spare elements per MCT would be required as needed to prevent the instability, uncontrolled islanding, or cascading (thus a smaller unit than would be necessary for an equivalent LPT). Of course, this is after sufficient empirical data exists to establish a basis for calculating the MCT’s reliability, availability, and maintainability.

Cyber Security

This section describes the NERC approach to categorize system relevance in term of to cyber security issues. This facilitates the planning of MCTs deployment, allowing for informed choices that would avoid testing a novel technology in a highly critical environment.

Eleven out of the twelve NERC Critical Infrastructure Protection (CIP) standards [NERC, CIP] deals with cyber security issues (CIP-002 through 011, and CIP-013), while one (CIP-014) concerns itself with physical security.

CIP-002-5.1a establishes the criteria “to categorize their BES Cyber Systems based on the impact of their associated facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System.”

[8] This last item intends to include situations where engineering judgment and the principles of conservative design apply.

The NERC standard provides guidance on the interpretation of the "affect the reliable operation of the BES" verbiage, with a definitive guidance on the definition of the impact rating criteria. These can be summarized as follows:

- High Impact Rating includes cyber systems used by control centers or backup control centers[9] for
  - Reliability Coordinators
  - Balancing Authorities (3,000 NW and above)
  - Transmission Operators
  - Generation assets
- Medium Impact Rating includes cyber systems not listed above and associated with
  - Single generator or group of generators at one site with aggregate capacity of 1,500 MW
  - Single resource or group of resources at one location (excluding generation facilities) providing 1,000 MVAR or more of reactive power.
  - Generation facilities necessary to avoid an "Adverse Reliability Impact."
  - Transmission facilities operated at 500 kV or higher.
  - Transmission facilities operated between 200 and 499 kV with interconnected lines meeting "Weight Value" requirements.
  - Generation or Transmission facilities critical to the derivation of Interconnection Reliability Operating Limits (IROLs)
  - Transmission facilities essential to meeting nuclear plant interface requirements.
  - Special Protection Scheme (SPS) or Remedial Action Scheme (RAS), or automated switching of BES elements.
  - Automatic load shedding schemes.
  - Control centers or backup control centers not identified above (in High Impact Rating) for
    - Generation assets of 1,500 MW or more
    - Transmission assets
    - Balancing authorities of 1,500 MW or more

- Low Impact Rating. Generally, BES systems that do not fall in either High nor Medium Impact Rating, as listed above

Physical Security

The CIP-014-2 deals with the physical security and is designed to identify and protect assets that, if rendered inoperable, would have serious consequences to the operation of the interconnection.

[9] Minimum criteria are specified in the standard, e.g., 3,000 MW and above for BAs, reactive resources of 1,000 MVAR or greater, assets involved in special protection schemes, etc.

Specifically, the purpose, as stated in the standard, is to "identify and protect transmission stations and transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or cascading within an interconnection."

Ideally, an interconnection will not contain any substations or control centers that, if lost, would cause any of the conditions listed above, as the focus of the CIP-014-2. However, a specific analysis for the presence of these conditions should be performed for transmission facilities that are characterized by any of the following:
- are operated at 500 kV or above (except generator collector buses)
- are essential to meeting nuclear plant interface requirements
- are critical to the derivation of IROLs
- are interconnecting transmission lines meeting the minimum aggregate metric[10] specified in the CIP-014-2 standard.

[10] Weight of line operated at 200 to 299 kV is 700, weight of line operated at 300 to 499 kV is 1300. 3,000 is the aggregated limit for consideration. Lines operated at <200 kV are not considered in this evaluation.

4.23 Value propositions for MCT

The main technical aspects that characterize the MCT concept are first summarized in Sect. 2.1. It will be then shown how these features lead to advantages in terms of both increased system resilience, and improved performance for grid operations, as discussed in the following sections 2.2 and 2.3, respectively.

4.23.1 Summary of the Defining MCT Features

Active and Reactive Power Regulation

The ability of achieving power flow regulation (both active and reactive) on the grid through the insertion of power electronics controllers has been previously demonstrated (e.g. Unified Power Flow Controllers, UPFCs [Gyqyi, 1995]). The proposed MCT approach builds on this established know-how, with a completely integrated system that includes both the high-voltage transformer and the electronic regulator, designed for a given range of power flow control needs.

More specifically, as compared to a conventional UPFC-based retrofit of a large power transformer (LPT), the MCT integrated magnetics/power electronics technology takes advantage of a properly designed tertiary winding, that may not be present (or at least not with the same required features) in transformer units already installed.

The tertiary feeds the MCTs power stage (IGBT[11] based) that is inserted, one per phase, in series to the secondary winding, as an independent a/c voltage source that can be fully controlled both in magnitude and phase, thus providing a four-quadrant power regulation (up to the power level available on the tertiary).

Lower than Nominal Line Voltage Rating

The fractionally-rated converter approach requires components that are working at a nominal voltage that is only a fraction of the line voltage.

For example, with a 5% power control capability, the power electronics will be required to carry the full line current but only at 5% of the voltage. Thus, a 69 kV line would require only 3.45 kV nominal value for the voltage regulation. This represents an advantage in terms of cost and availability of components, and simplifies the design to higher voltage transmission lines (*e.g.* could be applied for a step-down transformer from 500 kV to 230 kV).

[11] IGBT: insulated gate bipolar transistor

Continuous Voltage Control

The MCT electronically controlled voltage injection provides an advantage over a conventional reactive compensation bank: the Pulse Width Modulation (PWM) of the IGBTs, and the passive filtering for harmonics suppression, ensure the ability to control the injected voltage waveform smoothly and precisely in a continuous fashion, while reactive compensation units can only provide a discrete type of corrective actions, and can be inserted or removed only when the reactive power flow is within a given VAR range.

Fast Control

The power electronics controller is the key element for the MCT ability to operate with a variable range: at its core, the IGBTs are driven at a 1 kHz switching frequency, thus providing the ability of fast control within a fraction of a power cycle (in principle, 1/16, or 1 ms).

The power stage can be driven via fast electronics interfaced with any digital type of control and communication; thus, the only significant latency in the system is effectively due to the limitations of the switching frequency.

Modularity

The MCT approach considers multiple (or as low as two) units operating in parallel, instead of a single transformer. In general, the larger the required MVA node capacity, the more advantageous the MCT approach. The matching requirements for the placement of modules in parallel is guaranteed by the ability of adjusting the single impedances of each module.

This can be accomplished while also ensuring in an optimized operating mode, with respect to the overall grid impedance (as seen by the grid to which the node is connected), and to the need on limiting the reactive power flow. With a relatively simple sensing electronics and processing in place, the regulation can be done automatically, on a continuous basis, as the load characteristic change.

4.23.2 Impact on Resiliency

Addressing Concerns about Large Power Transformer Damages

From a resiliency[12] perspective, the MCT approach provides an answer to an important concern in the industry, related to the possible need of replacing LPT units on an emergency, or unforeseen basis. Especially for nodes with large capacity, a suitable replacement should be made available with minimal impact on the ability of serving the load.

The term "suitable" in this context refers to:
- A permanent solution that provides the same operational capabilities that were present with the previous unit

or
- A temporary replacement (possibly from a spare pool) that "keeps the lights on" to minimize the impact on the population and local economy

The former solution is obviously preferred, but a tradeoff may need to be considered for situations where the procurement time delay is unacceptable, and interim solutions are available.

In this context, the MCT approach, due to its ability of impedance regulation, can provide the optimal (that is permanent) solution, with replacement times that are the same or less as for the installation of a suboptimal component, that will be in service only on a temporary basis.

High-Impact, Low-Frequency Events

The need of replacing a LPT on an emergency basis is, fortunately, a rare event. While spares can in some cases, provide a solution (as also discussed in Sect. 2.2.1), however, just because these events are rare, there is also a limited set of options for providing multiple replacement units without a significant delay. These situations that are considered are unexpected and, thus, outside the typical planned replacement schedule of the transmission owner.

The resilience issues are considered in the context of an emergency response situation due unforeseen contingencies, such as:
- Failed units due to impact of natural events: e.g. more commonly, flooding, earthquakes, and, less commonly, impact of space weather events (Geomagnetic Disturbances).
- Failed units due to damage caused by equipment mis-operations, design flaws, including at the substation system level, e.g. misplacement/misoperation of arrester that would cause LPTs aging faster than predicted, due to switching or lightning strikes over-voltages
- Intentional damages, e.g., physical attacks, including Electromagnetic Pulse (EMP)

[12] Here adopting [NERC, 2012, p. 11] definition: "Infrastructure resilience is the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event."

Events of this type are typically labeled as High Impact, Low Frequency (HILF, [NERC, 2010], [Veeramany, 2015]). They are then, by definition, not suitable to a statistical analysis, because the data sets are very small or non-existent. For the same reason, while to estimate the probability of failures a proper risk analysis would be in order, the very definition of probability may be questionable unless an extremely long interval of time is being considered (*e.g.* centuries).

As partial solution, for the specific case of Geomagnetic Disturbances (GMD) impact, in the context of space weather events, a methodology for the development of a statistical analysis has been devised [Pulkkinen, 2012]. This technique is based on an extrapolation of the probability distribution built over a collection of more frequent events, similar in nature, but with much lesser impact (that is smaller amplitude GMD, in the case under consideration). In principle, this approach could also be considered for the analysis of other types of HILF events.

Another type of statistical analysis was developed by [Geneder, 2014], in reference to the risk evaluation for intentional, local attacks to critical infrastructures. These refer to physical, or small "Tactical" EMP or Intentional EMI attacks, and the analysis is based on the evaluation of the type of accessibility of, and mobility within the target facility, that would be required to create a significant damage.

These methods could be instrumental for quantifying, with some statistical rigor, the potential economic impact of low-probability events, and the justification for investments towards damage prevention using technologies that lead to an increased level of security.

In the same context, another approach that could be useful is a sensitivity study. Rather than identifying a probability of an event, the analysis would consider that the occurrence of an event, however unlikely, and look for what consequent damages are possible. From there one can then identify how much electric load would be impacted, and how that scales with the extent of the postulated impact (e.g. a single transformer, a substation, or an entire area). In absence of any further information about the event probability, the priority from a grid security and resiliency retrofit perspective will be given to those assets that carry the highest sensitivity to the loss of load (possibly weighted in terms of load criticality).

Damage Cost Analysis

The resiliency can be characterized by a figure of merit defined as the product of two factors: the loss of capability of serving the load (e.g. in MVA), and the time during which the loss of load occurs, measured from the time of the contingency occurrence, to the time the replacement unit is back in service. This quantity is therefore energy that has not been delivered.

It can be observed that, in general, a large LPT requires more time to be built, delivered and installed. It will also, obviously, impact more load. Therefore, the LPT capacity (in MVA) will impact both factors that yield the resilience figure of merit. For this reason, the resilience will have a higher-than-linear dependence on the size of the asset loss. In other words, the impact on resiliency grows faster than the capacity of the loss.

The economics of the required technology investment is an important factor in the evaluation of strategies to improve the grid resilience. From the LPT replacement perspective, this would require estimating the probability of losing a given number of LPT's over the course of a specified time interval (in years).

As an example, it is considered the case of an average loss of one transmission-class transformer every 10 years. For a 100 MVA unit (for example), the replacement cost, including installation is estimated at of 5 M$, thus leading to an average yearly cost of 0.5 M$/yr.

Assuming a lead time for procurement and replacement of 0.5 years, then the impact on resiliency is represented by the energy that is not delivered, that is 100 MVA for 0.5 years, or 50 MVA·yr.

If a cost of electricity (COE) of 0.1 $/kWh is assumed [EIA, 2018], or 100 $/MWh=876000 $/(MW-yr] (here MW~MVA), then COE=876,000 $/(MVA·yr) ~ 1 M$/(MVA·yr).

The economic impact of the loss is then:

$$50 \text{ MVA·yr} \cdot 1 \text{ M\$/(MVA·yr)} = 50 \text{ M\$}$$

over a 10 year period, that is the yearly average cost is 5 M$/yr

In summary, the assumed event costs an average 5.5 M$/yr: this amount is almost entirely due to the loss of service. This type of figure could be used as a basis for estimating the advantage of MCT's, following a similar cost analysis, and reflecting the reduced cost of the loss of service, that is the improved resiliency with MCTs, due to both the availability of some fraction of the power (due to the modular design) and to the shorter time required to procure the replacement module (due to the smaller size, as compared to the reference LPT).

Reduced Impact of Probability of Failure

An inherent advantage of the MCT approach is the impact of the modular design on the contingency level to be considered. Typically, grid operators plan to up to N-1 contingencies, i.e. the "system" (e.g. ISO/RTO, or smaller) shall still serve the load (up to peak values) even if a generation or transmission node becomes inoperable.

One can assume that the probability of an "event" that leads to a node to go off-line is uniformly distributed over time, thus if this probability is of *n* event per year, these events, on average, will be uniformly spaced over 12/*n* months (in other words, it is not very likely that two of such events occur at the same time, or very close in time).

This leads to the assumption, that, for a given time interval, the probability of one failure of an LPT is the same as that of one failure of one of the modules of an MCT, while all the other modules are fully operational.

One can then consider two scenarios: a "reference", LPT-based grid, and its upgrade with MCTs. Let M_{MCT} be the number of modules that are considered to replace a single unit LPT.

With the MCT approach, from the perspective of the impact on the load, one contingency in the reference grid becomes then equivalent to a N-1/M_{MCT}. For example, for three MCTs replacing a single LPT, a N-1 contingency in the "MCT grid", becomes equivalent, from load impact, to N-1/3 in the reference grid. Again, as it was discussed, the (reasonable) assumption that was made here is that the loss of one LPT or the loss of one of the three modules of an MCT, have the same probability.

The MCT brings then the benefit of leading to a higher level of resiliency, since now an N-3 contingency is required to cause the same consequences that an N-1 contingency would have in the reference grid.

Furthermore, even for this N-1/3 equivalent impact, the cost and time required to replace a 1/3 size transformer is also reduced (albeit not necessarily by a factor of 3 as compared to the original size, three times larger).

An additional, implied, assumption is that the failure mode is such that the remaining M_{MCT} -1 modules can continue to function, even though one is failed. With MCTs there are more units, thus more possible failures, however this is accounted for in the assumption that the failure are statistically uniformly distributed in time.

This argument would no longer apply (or not entirely) when the number of unit increases to the point that the average time between two failures (of two separate modules) is comparable with the time that it takes to replace a unit. In this case there is time interval where two (or possibly more) failures have occurred. It is easy to see that the overall resiliency is still improved for a "realistic" transformer size and a limited number of modules, e.g. $M_{MCT} \approx 5$. In other words, there is no advantage in choosing a very large number of modules, even if economics was not an issue).

In summary, the modularity that comes with the MCT approach provides the ability of a substation to serving the same load, even with reduced MVA capacity.

As an example, a case with two LPTs, each with nominal power level of 100 MVA is considered. The LPTs are serving a 150 MVA load (thus, realistically, not working up to their capacity limit). If one LPT goes out of service the operator, while fully loading the remaining transformer, must dispatch at least 50 MVA from another route, with potential increase in losses, price, reduced service reliability, and possibility of loop flows.

In a similar situation, but with MCTs, with M_{MCT}=3, one-unit failure will lead to a loss of 33 MVA capacity, and the two MCT nodes can still serve the load without need of any re-dispatch.

<u>Advantage for replacement: smaller units easier to procure and transport</u>

The estimate of the cost impact for transportation of large, out of ordinary (i.e., not the typical loads carriers are accustomed to moving) units is required when planning replacement of LPTs.

Clear advantages exist if the MCTs are instead considered. For example, in estimating transportation costs, issues such as over-the-road vs rail/barge, typical bridge load bearing capacity and clearance, should be considered. A meaningful cost evaluation of the difference cannot be done without considering a specific case, including local grid topology, geography, and accessibility.

This evaluation should also include issues (that offset in some smaller amount the advantage of MCTs) related to the larger substation real estate required to install M_{MCT}>1 units (3 smaller units take more than just 1/3 of the space of the original one), and possibly the limits due to logistics of concurrent installation of units in near proximity and crew size required.

<u>Replacement with Optimal Impedance Matching</u>

With MCTs, the power electronics controller allows regulation of the impedance, for each module. Thus a few standard choices for MCT unit sizes can meet the requirements of many more different situations, obviating the need for replacements that are custom-designed to tight specifications related for a particular location in the system. Standardization in the industry offering leads to a reduced procurement time, and also enhances the possibility of obtaining a replacement unit from a nearby installation that is, too, equipped with MCTs, where redundant unit may be present.

If choices are available, it is recommended to select the MCT characteristics such that, during typical operations, the need of the power injection from the electronic regulator is close to zero or at minimum level. This will provide increased flexibility to follow daily load variations, meet power regulation needs, and prevent conditions where the power electronics units are required to work constantly at their maximum rated power.

MCT Design Vulnerability

A key assumption to support the proposed approach, is that the probability of failure of a single module of an MCT is the same as that of the larger LPT considered for replacement (as discussed in Section 2.2.4). This would imply that the same quality control standards are applied to the modular units and that the power electronics section does not pose additional vulnerabilities. While the former is certainly a good assumption, the latter is not.

An increased complexity necessarily leads to an increased vulnerability. Therefore, proper risk management process needs to be embedded in the design.

Risk data related specifically related to the vulnerability of the power electronics controller (even if a fail-safe switch is included) need to be considered for a reliable evaluation of the resilience improvement resulting from the adoption of the MCT approach.

Along these lines, a risk analysis should include the following:

- Discussion on the impact on resiliency related to a variety of threats or failure modes that can impact the power electronics and related enhanced protections (e.g. shielding, surge suppressors) to ensure MCT's full functionality
- Design strategies for protecting the power electronics due to failure modes and specific threat impact

4.23.3 Impact of MCTs on Improved Grid Operations

Existing vs. Planned Installations

This section discusses the relevance of the MCT approach beyond the aspect of grid resilience. This provides an important link to the grid modernization effort, as MCTs have the potential of becoming the key assets that control and ensure optimal grid operations at all times

There is a value in considering MCTs deployment in the existing infrastructure, however the case of the replacement of existing, functional LPTs with an equivalent MCT should be made on a case by case basis. Typically, that would be the situation where the economic valuation of the benefit in terms of operations (especially for a node that serves congested areas and/or critical loads), the age of the LPT, and possibly an expected growth that would require new power lines or substations, would suggest that replacing an operational LPT with a new MCT could be advantageous (or with a short-term cost recovery).

However, in general, there is a clear advantage that comes from considering MCTs in the context of new installations, following a grid expansion plan. The grid expansion provides a increased market opportunity for MCTs, arguably quite larger than just the replacement for contingencies due to damaged LPTs.

The advantages of the introduction of MCT in terms of grid operations are listed below. The economics of the value-added can be estimated based on specific data for any given service territory. The overall picture, however, is that of MCTs providing a much-needed flexibility for a continuous, real-time control and optimization of the grid performance. This advantage will be even more important in a highly meshed grid structure, and fits within the general trend of moving towards a highly integrated, "smart-grid" approach.

Loop flow control

The MCT technology, especially if developed at the high-end of transmission line voltages, can alleviate loop flow concerns, in particular as related to sudden load changes or fault events.

For instance, the MCT power electronics controller can automatically respond to the need of rapid impedance changes, and allow for grid operation setups that counter congestion conditions at their onset. A meshed grid environment relying on MCT will be able to modify in real time the impedances of the different routes available for avoiding congestion.

In this context, a regulatory environment that favors the installation of MCTs on adjacent, independent RTO/ISO areas would be particularly beneficial for assuring the most efficient operations on an entire interconnect.

Reduction of Tap-Changing and Reactive Compensation Switching

With MCT units inserted in some of the grid nodes that are subject to large load variations, the need of tap changing operations may either eliminated or greatly reduced (for example, considering a large ISO service area).

Transient power flow simulations can be developed to identify and prioritize the nodes where the MCT insertion would be more effective as a substitute of tap changing, and to provide a quantitative estimate of the overall economic value resulting from smooth, continuous voltage regulation (vs. discrete and time-constrained).

From a grid operator perspective, the ability to avoid tap-changing and on/off -line switching of reactive compensation units provides a great simplification, and a risk reduction for normal day-to-day operations.

An economic quantification of these advantages (without even including the reduced impact on grid operator personnel monitoring, and reduced maintenance or failures related to tap changing operations) can be derived by comparing the reactive power flow before tap-changing and/or reactive compensation switching, vs. the same case where MCT control is utilized.

It is then assumed that the MCTs provide a real time compensation, while for the conventional case, on average, a given reactive power flow is accepted for a given time interval Δt.

This corresponds to the typical scenario where the reactive power has not reached the sufficient level required for the insertion of a reactive compensation unit. This may persist for a while, until a given threshold is reached, and the compensation unit is switched online.

On the other hand, MCTs would allow to compensate immediately for the reactive power. A proper analysis of the power flow (including the impact on generation) for the case where the MCTs provide correction can then lead to a meaningful cost estimate.

Increased Margin to Voltage Collapse and Transient Stability

If properly instrumented and driven, MCTs can behave as “intelligent” nodes allowing for active grid stability control.

MCTs engaged in real-time control, even for limited areas, can significantly reduce the margin required for preventing the onset of voltage instability conditions during N-1 (or worse) type of contingencies. In other words, the pre-contingency state can be made more robust against potential instabilities that would be triggered by N-1 situations.

Thus, optimization of power flow, load balancing and reduction of reactive power on the grid can provide a significant advantage, as compared to typical operating modes, in the ability of utilization of the transmission infrastructure closer to its desired nominal levels, knowing that the stability margin in contingency situations is increased.

Protection against Geomagnetic Induced Currents

The MCTs power electronics stage is a line series element, and as such provides the option of implementing a GIC-blocking device operating directly on each phase (without involving the transformer neutral, in wye-configurations). This would not just mitigate, but eliminate the GMD (and EMP-E3) threat for LPTs connected to long transmission lines.

This can be implemented with a small change from the perspective of software driver of the power electronics, with respect to the normal MCT design. Arguably, this could certainly be compensated by the additional cost of a stand-alone GIC blocking device, that would require a switch-bypassed capacitor in series on the neutral, or on the phase conductor for concerns related to high-power transformers under fault conditions, autotransformers, etc.

Phase balancing

MCTs has the inherent ability of providing an independent voltage control on each phase (through the power electronics).

For step-down units from transmission to sub-transmission, or distribution level, a properly equipped driver for the electronics controller can provide an effective, real time the phase balancing, with a significant improvement in the distribution network.

Results:
Modular Controllable Transformers represent an appealing solution for wide spectrum of enhancements for the power grid.

Benefits ranging from improved resilience, to more reliable operations and modernization in the planned grid expansion, lead to a strong economic proposition that warrants a fast-track development and testing effort.

In perspective MCTs can become the key elements of a fully integrated grid featuring, a substantially improved ability of self-regulation, and operating closer to optimal conditions at all times.

4.24 Conclusions

The project concludes that MCTs provide extreme flexibility in traditionally passive parts of the system. As a control solution, the MCT approach is a relatively cheap and retrofittable solution requiring minimal modifications to existing systems. Issues associated with grid resiliency are remedied by improving the resistance to failure, reliability, and drastically reducing recovery times.

The work conducted in this project investigated key aspects of converter and transformer design as well as detailed simulations. Simulation on IEEE 30 and 13 bus systems showed the dynamic control over voltage, congestion, impedance and power flow that can be obtained by using the MCT approach. The work also identifies commercial option for converter design and housing that ensure that this approach does not become a custom device-based approach. Resilience studies conducted showed that the approach not only surpasses current replacement options, but it also allows much better ranges of operation over nominal grid operating points.

By incorporating a fractionally rated unit to allow huge amounts of control, availability of lower power components can be ensured while reducing costs over fully rated approaches. Furthermore, by incorporating granular control, much smoother waveforms and fine regulation can be achieved making this approach better than discrete switching approaches like LTCs or switched capacitor banks. With relatively simple local controls, matching between uneven impedances can be achieved. The modularity of this approach ensures that relatively simple controls have to be embedded while delivering high performance. While High-Impact, Low Frequency (HILF) events are rare, the presence of MCT based control makes recovery much faster and allows operation in partial failure modes without compromising the entire system. Furthermore, by splitting larger units into small modular units with control the probability of failure or expected outage goes down dramatically. Even in cases where the modular units fail, the replacement time is dramatically reduced owing to lower lead time on modular standardized units.

Replacement of current LPT units in the fleet would have to be analyzed on a case-by-case basis. The main pivot point of this analysis would hinge on the value of the added control at the particular location. However, as seen in the preceding sections there is always a need for higher resiliency and control with more DERs being added to the resource mix. In general, this approach definitely is more advantageous when considering grid expansion endeavors. Increasingly meshed grid topologies allow the MCT approach to have a clear advantage over traditional LPTs. In terms of current operating regions in the national grid, the MCTs serve to regulate interconnects between ISOs and RTOs making market regulation easier. This could potentially make the problem of calculating LMPs and pricing slightly easier. The grid structure as a whole could be utilized much more by squeezing additional capacity out of under utilized assets.

It has been seen that from a regulatory stand point this solution has no significant obstacles. Designs proposed by Delta Start for mobile transformer units show that the unit can be shipped extremely fast while minimizing commissioning and recovery time. By making standardized units and changing the apparent impedance through active control, one type on unit can be used to replace multiple types of existing field units. Furthermore, the number of spares to be maintained drastically reduces due to the same. Inputs from Southern company have shown a real need for such a solution and designs have been presented in this report for the target ratings of interest. The MCT approach shows much promise in numerous regards.

With the exponential rise in DERs, utilities and infrastructure management agencies are seeing a need for such a solution to manage the unpredictability without meticulous centralized controls. Recent reports have shown the import requirements for LPT builds. By standardizing them, high economic value can be realized making this approach attractive to transformer manufacturers. Moreover, grid management agencies could retrieve more data from such units over traditionally unmonitored section furthering the grid-modernization initiative. These multifaceted advantages make the approach very attractive to manufacturers and grid regulators.

Future efforts for this project would include, further analysis of the converter topology. Challenging issues for the build such as BIL requirements, environmental constraints and packaging need to be addressed. The converter unit needs to be mobile and compact. The team has proposed building a scaled down prototype with the hope of testing it and understanding key build issues. The controls for this device will further be defined. Optimal modes of operation under different grid conditions need to be understood. Further, the actual transport constraints for the modular transformer unit can only be studied with a built unit. The team has proposed building a modular transformer in partnership with Delta Star Inc. to understand these issues. The MCT approach shows much promise as a cost effective approach to achieve dynamic control as well as grid resiliency.

4.25 Opportunities for Training and Professional Development

Nothing to Report

4.26 Dissemination of Results to communities of interest

Nothing to Report

4.27 Goals for the next reporting period

- Final report at the end of the project is presented here.

SECTION 5.0 PUBLICATIONS

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