A low-angle, close-up photograph of a high-voltage electrical transmission tower. The image shows the intricate lattice of steel beams and cross-arms supporting multiple high-voltage power lines. The perspective creates a sense of height and scale, with the tower receding into the distance. The image is tinted with a light blue/teal color.

Advanced Transmission Technologies Framework

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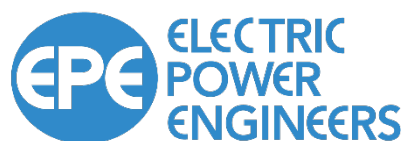
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Introduction

U.S. electricity demand is projected to grow by nearly 16% by 2029, underscoring the urgency for grid upgrades and the integration of new generation resources¹.

Transmission owners and grid operators typically prioritize conventional investments, such as reconductoring existing transmission lines, rebuilding infrastructure, or constructing new lines. However, even when expansion is justified, these traditional investments are often slow, capital-intensive, and subject to permitting, regulatory, and environmental constraints. Therefore, a modernized approach is essential to meet future electricity demands reliably and cost-effectively.

Advanced Transmission Technologies (ATTs) offer a strategic pathway to modernizing the grid by optimizing existing infrastructure, increasing transfer capacity, and supporting the reliable integration of renewable energy resources. These technologies—ranging from advanced conductors and power flow control devices to voltage support equipment and digital optimization tools—enable transmission providers to address system constraints more flexibly and in shorter timeframes. When deployed strategically, ATTs can defer or even eliminate the need for large-scale capital projects while maintaining or improving system reliability, resilience, and efficiency.

This framework has been developed with consideration of the objectives established in **Senate Bill 422**. The technology background, applications and benefits, use cases, technical and operational considerations, and other attributes are structured to provide a consistent foundation for the subsequent Technology Attribute Matrix. This approach enables the characteristics and capabilities identified through the framework to be systematically mapped to the relevant Senate Bill 422 objectives in the next stage of the evaluation. In this way, the framework serves not only to characterize each technology, but also to establish the technical basis for a clear and traceable technology-to-objective mapping.

According to recent data from Lawrence Berkeley National Laboratory², approximately 2,600 gigawatts (GW) of proposed generation and storage capacity seeking interconnection are ultimately withdrawn. Even among projects that proceed, many face multi-year delays, primarily due to thermal, voltage, or stability constraints that would otherwise necessitate major transmission upgrades. By contrast, ATTs can often serve as viable mitigation measures to relieve bottlenecks, reduce study timelines, and enable earlier in-service dates for clean energy resources—thereby accelerating decarbonization objectives while enhancing grid access and equity.

¹ J. D. Wilson, Z. Zimmerman, and R. Gramlich, “Grid strategies, strategic industries surging: driving us power demand,” *Grid Strategies*, December 2024.

² J. Rand, N. Manderlink, W. Gorman, et al, “Queued up: 2024 edition, characteristics of power plants seeking transmission interconnection as of the end of 2023,” *Lawrence Berkeley National Laboratory*, April 2024.

Despite their proven technical efficacy, ATTs remain underutilized due to a range of institutional and practical barriers, including lack of awareness, misaligned incentives, fragmented cost allocation mechanisms, and limited experience among planners and operators. The integration of these technologies into planning and operations frameworks also requires updated modeling practices, enhanced coordination across utility functions, and stakeholder engagement to build confidence in their performance. As such, thoughtful frameworks like this document are essential to bridge knowledge gaps and support informed decision-making.

This report serves as a comprehensive guide to nine categories of ATTs, presenting their functional roles, technical principles, grid applications, implementation considerations, and best-practice examples from the U.S. and international contexts.

These technologies include:

- Advanced Conductors,
- Advanced Power Flow Control,
- Transmission Switching,
- Tower Lifting,
- Static Synchronous Compensators (STATCOMs),
- Static VAR Compensators (SVCs),
- Synchronous Condensers,
- Voltage Source Converters (VSCs), and
- Dynamic Line Rating (DLR)

Each chapter provides IURC-specific insights where applicable, and collectively, the report supports strategic deployment aligned with IURC's system planning objectives.

Importantly, this framework emphasizes the multi-dimensional value of ATTs—not only for generation interconnection or congestion relief but also for enhancing system resilience, optimizing right-of-way utilization, mitigating extreme weather risks, and improving operational flexibility. In many cases, ATTs can be deployed incrementally and with modular scalability, which aligns well with adaptive planning approaches and evolving policy targets. Their role is particularly critical as transmission systems are increasingly expected to handle variable and bidirectional power flows resulting from high levels of renewable integration and distributed energy resources.

As IURC continues to pursue an affordable, reliable, and decarbonized energy future, the strategic adoption of ATTs offers a unique opportunity to modernize its grid infrastructure in a proactive, technology-driven manner. By embracing these technologies, IURC can unlock greater value from its existing assets, improve service to its stakeholders, and position itself at the forefront of innovative grid planning practices. This framework provides the foundational knowledge and guidance necessary to support that transition.

1. Advanced Conductors

1.1 Introduction

As global electricity demand continues to rise, the need to expand and upgrade transmission networks becomes more critical. The integration of new generation assets, particularly from renewable energy sources, presents challenges to existing grid infrastructure, often pushing the limits of traditional conductors' thermal capacities. This has led to the development of ATTs, with advanced conductors playing a key role in managing grid congestion, improving reliability, and accommodating the growing demand for clean energy.

The development and integration of advanced conductors have emerged as a critical solution for improving the capacity of transmission systems. In contrast to traditional conductors like the Aluminum Conductor Steel Reinforced (ACSR), advanced conductors leverage material science and innovative engineering to enable more efficient power transfer across the grid. By utilizing modern materials and manufacturing techniques, these conductors achieve higher thermal capacities, allowing them to operate at elevated temperatures for extended periods. This is achieved without compromising on the structural integrity of lines and existing infrastructure. This increased capacity results in enhanced ampacity, allowing higher currents to flow through transmission lines, while also mitigating issues such as excessive sag and thermal elongation. Advanced conductors enable solutions such as reconductoring, allowing existing lines to be upgraded without the need for new infrastructure, thus overcoming the constraints of limited space and rights-of-way (ROW).

The use of advanced conductors is also critical to meet the stringent safety and operational standards of modern power grids. These conductors offer significant advantages, including reduced sag, increased durability under extreme weather conditions, and the ability to handle higher operational and emergency temperatures. Particularly, advanced conductors have become essential in areas requiring long-distance spans, such as river crossings, and in projects where environmental or regulatory constraints limit infrastructure expansion. Moreover, the increased efficiency and lower installation costs of these conductors provide a compelling case for their widespread adoption in both the construction of new transmission lines and the reconductoring of existing ones.

This chapter explores the varied applications and benefits of advanced conductors. The following subsections provide an in-depth examination of the fundamental technology of advanced conductors, the various drivers of advanced conductor deployment, and some best practices for their utilization.

1.2 Technology Background

1.2.1 Background and Motivation

Advanced conductors employ material science to increase the power transfer capacity of lines, when compared with conventional conductors, particularly the ACSR conductor. Typically, novel or existing materials with associated manufacturing processes are used in the new lines to achieve operation at higher temperatures for extended periods of time. This results in a higher current-carrying capacity (i.e., ampacity) and generally lower sag. In this way, the thermal capacity of power lines is increased.

The electric grid continues to witness a large integration of new generation assets to meet a rapid increase in load growth. Planning studies often reveal that such interconnections will potentially overload portions of the transmission network. This depends on the ampacity of the lines considered. Various characteristics of conductors impact the current-carrying capacity of lines, including cross-sectional area, operating temperature, heat dissipation from material surface, and electrical resistance (loss/efficiency).

Overloads are typically manifested by exceeding a line's thermal capacity or by excessive conductor sag. For safety and reliability, it is essential to maintain adequate clearance between the lowest point of an energized transmission line and objects on the ground, a factor directly influenced by conductor sag.

To address the need for increased power transfer capacity, transmission line upgrades must overcome constraints related to both thermal capacity and sag. There are two primary approaches to achieving this:

- **Building New Transmission Lines:** This may, in some cases, be impeded by challenges in acquiring ROW, other environmental assessment reviews and overall project costs.
- **Reconductoring:** This involves upgrading the line conductors with higher capacity conductors while using the same or most of the existing supporting infrastructure and maintaining clearances and ROW.

It is important to note that advanced conductors can be used in both new builds/rebuilds and in reconductoring to achieve higher capacities.

1.2.2 Advanced Conductor Characteristics

The most commonly used conductor in the electric grid has traditionally been the ACSR conductor. This has therefore served as the conventional conductor for high voltages over the past century, with minor modifications for unique applications. It consists of multiple hardened aluminum strands for conductivity, wrapped around a galvanized core of steel wires that allow the conductor to handle tension and support the weight and achieve the required sagging. ACSR conductors are designed to operate at temperature levels of up to about 200°F (or higher for brief emergency conditions). An early enhancement to the ACSR is the replacement of core with modern high-strength steel to produce the Aluminum Core Steel Supported (ACSS) conductor.

Advanced conductors typically replace the conventional steel core found in ACSR and ACSS with ultra-high-strength steel or a composite matrix core made from carbon, metal, or ceramic fibers. The lighter weight of these modern composite core materials enables the use of more conductive aluminum strands while maintaining the same structural loading. Additionally, these materials offer greater strength than traditional steel cores, which results in reduced conductor sag and allows for higher current-carrying capacity.

In some cases, such as certain ACSR applications, advanced conductors also incorporate heat-dissipating coatings to improve thermal efficiency. While a wide range of proprietary trade names exist for different types of advanced conductors, they can generally be categorized using the following descriptors (or combinations thereof)³:

- **Type of Core**, e.g., composite-core, ultra-high strength steel core.
- **Specific Function**, e.g., high temperature super conducting, high temperature low sag (HTLS), equipped with heat-dissipating coating.
- **Proprietary vs. Non-proprietary**⁴, e.g., Non-proprietary conductors (typically with expired patents) are used for general applications, while proprietary conductors often combine multiple advanced features tailored for specific use cases.

Key features that make advanced conductors particularly suitable for reconductoring, when compared to conventional conductors, include:

- Lower thermal elongation rate
- Reduced daily sag
- Same or lower outer diameter
- Same or lower electrical resistance
- Comparatively easier installation method
- Compatibility with conventional installation fittings

A description of the most used types of conductors and conductor enhancements is provided in Table 1³.

³ G. Sibilant, “Advanced Conductor Specification Guide,” *EPRI 2024 Technical Update*, 2024

⁴ “Grid-Enhancing Technologies for Smart Energy Transition,” *EPRI*, 2024.

Table 1: Most Commonly Used Types of Conductors

Conductor	Description
ACCC	Aluminum Conductor Composite Core: Uses a lightweight composite core to increase strength and reduce sag.
ACCR	Aluminum Conductor Composite Reinforced: Reinforced with advanced materials to allow high-temperature operation with minimal expansion.
ACFR	Aluminum Conductor Carbon Fiber Reinforced: Utilizes a carbon fiber core for high strength and low sag at elevated temperatures.
ACPR	Aluminum Conductor Polymer Reinforced: Employs a polymer-based core to reduce weight and sag while improving thermal performance.
ACSS	Aluminum Conductor Steel Supported: Designed for high-temperature operation, using annealed aluminum strands and a steel core.
E3X	Features a high-emissivity coating applied to the outer aluminum strands of overhead conductors to enhance heat dissipation and reduce energy loss.
TS	Thermoset Insulated Conductors: Insulated with thermoset materials that offer superior heat resistance and mechanical strength.
C7	Features a core made from high-conductivity materials (typically copper) to minimize resistance and energy losses.
G(Z)TACSR	Uses a Zirconium Aluminum Alloy-based ACSR conductor to offer improved thermal and mechanical performance.
(Z)TACIR (Invar)	Uses a Zirconium Alloy Aluminum Conductor reinforced with Invar steel, known for its extremely low thermal expansion properties.

Table 2 and Figure 1 compare advanced conductors with traditional ACSR⁵ conductors. These reveal significant improvements in key metrics that affect both the ampacity and sag of the conductors.

⁵ “Conductors for the uprating of existing overhead lines,” *CICRE*, April 2019.

Table 2: Advanced Conductor Characteristics Compared with Traditional ACSR Conductors

Conductor Type	Conductor Name	Rated Breaking Strength	Weight	Ampacity at Continuous MOT*	Resistance at 20°C	Resistance at Continuous MOT*
3M ACCR	795 Drake	102%	85%	158%	94%	129%
ACCC	795 T16	129%	96%	165%	77%	99%
ACSS/MAS	1029 Drake	103%	100%	174%	97%	146%
ACCS/TW/C7	973 Everglades	124%	92%	153%	82%	106%
ACCC/E3X	1029 Drake	129%	97%	186%	77%	99%
ACSS/TW/MA5	959 Suwanee	123%	121%	191%	80%	121%
ACSS/MA5/E3X	795 Drake	103%	100%	199%	97%	146%
ACSS/TW/MA5/E3X	959 Suwanee	123%	121%	218%	80%	121%
TS Conductor	1051 Sun M3	134%	96%	168%	75%	96%

*MOT – Maximum Operation Temperature

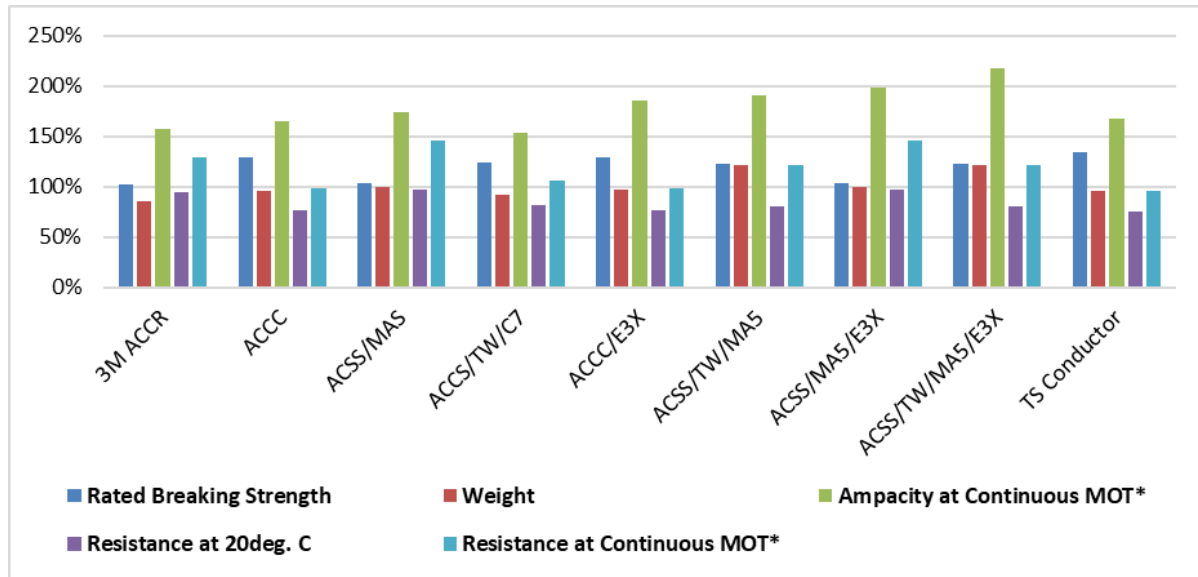


Figure 1: Advanced Conductor Characteristics Compared with Traditional ACSR Conductors

The most common functional requirements for deploying advanced conductors are high operating temperature and low sag performance. These conductors, often classified as HTLS conductors, are engineered to operate continuously at elevated temperatures while exhibiting significantly less sag than traditional ACSR conductors. HTLS conductors typically consist of heat- and annealing-resistant aluminum strands for conductivity, combined with a strengthened core that has a low coefficient of thermal expansion to minimize elongation under heat. Four primary types of core materials are used to achieve these characteristics:

- Steel Core
- Invar Steel Core
- Metal Matrix Composite Core
- Polymer Matrix Composite Core

Table 3 and 4 provide additional detail on the specific materials used for aluminum strands and conductor cores, respectively. Table 3 presents the maximum continuous operating temperature and short-term emergency temperature for various aluminum strands. Table 4 lists the continuous operating temperature of different core types, along with their modulus of elasticity, which reflects the mechanical strength and correlates with sag performance.

Table 3: Different Types of Aluminum in Conductors and Operating Temperatures.

Type of Aluminum	Maximum Operating Temperature (°C)	
	Continuous	Emergency
Hard Drawn, 1350-H19 (HAL) - ACSR	90	120
Thermal Resistant [IEC 62004] AT1 (TAL)	150	180
High Strength Thermal Resistant [IEC 62004] AT2 (KTAL)	150	180
Extra Thermal Resistant [IEC 62004] AT3 (ZTAL)	210	240
Fully Annealed [Cenelec 50540] 1350-0	250	250

Table 4: Characteristics of Core Materials Used in Advanced Conductors.

Core Materials	Modulus of Elasticity (GPa)	Max Continuous Operating Temperature (°C)
Zinc-Coated Steel	200	200
Invar Steel	162	200
Misch-Metal Coated	200	250
Metal Matrix	210	300
Polymer Matrix	124-150	180

1.3 Applications and Benefits

A wide range of drivers support the growing deployment of advanced conductors across power systems. These drivers can be categorized into three main implementation strategies:

- Reconductoring of existing lines,
- Upgrading existing transmission line infrastructure,
- Construction of new transmission lines.

The following subsections summarize the primary drivers and benefits of advanced conductor deployment, based on insights gathered from a survey of over 50 utilities.

1.3.1 Resolving Thermal Violations

One of the most prominent applications of advanced conductors is to address thermal violations on transmission lines. As the demand for electricity increases or new generation sources are integrated into the grid, existing infrastructure often becomes inadequate. This inadequacy is frequently manifested as thermal overload, where transmission lines exceed their rated current-carrying capacity (ampacity), risking overheating, excessive sag, and potential failure.

Advanced conductors offer enhanced thermal performance, enabling utilities to safely increase the power transfer capability of transmission lines without exceeding thermal limits. This makes them ideal for infrastructure expansion or reinforcement without the need for major construction projects. Key features contributing to this capability include:

- Higher continuous and short-time emergency temperature ratings
- Superconductivity of materials
- Application of heat-dissipating coating to improve conductor capacity

These features collectively enable utilities to maintain safe operation while increasing the current-carrying capacity of existing lines, making the resolution of thermal violations the primary driver behind the adoption of advanced conductors.

1.3.2 Congestion Management

Another key driver for the deployment of advanced conductors is the need to manage transmission congestion. In economic dispatch, grid operators typically prioritize low-cost generation resources. However, limited transmission capacity can prevent these resources from delivering energy to demand centers, resulting in the dispatch of more expensive generation and increased congestion costs.

Advanced conductors provide a cost-effective solution for alleviating congestion, particularly through reconductoring projects where existing structures and ROW can be retained. This approach avoids the lengthy permitting processes and high capital expenditures associated with building new lines. When selecting a conductor for congestion relief, several factors must be considered, including:

-
- Mechanical loading on existing towers and support structures
 - Projected long-term load growth
 - Capital and installation costs

As a real-world example, in 2018, Duquesne Light used ACSS/TW to reduce congestion on a 7-mile 138kV transmission line.

1.3.3 River Crossing and Other Ground Clearances Applications

Advanced conductors are also widely applied in transmission projects that demand minimal conductor sag, especially in scenarios involving long-span crossings and strict ground clearance requirements. These applications include river crossings, urban environments, and areas where maintaining a safe distance from ground-level infrastructure or vegetation is critical for reliability and safety.

In such situations, utilities capitalize on the low-sag characteristics of advanced conductors to achieve longer spans without the need for additional support structures. This is particularly advantageous in densely populated urban areas where space is limited, or in environmentally sensitive zones, such as river crossings, where conventional solutions may not be feasible.

Historically, achieving long spans, especially over rivers, often required the construction of support towers within the river itself to reduce span lengths and sag. However, these in-river structures are increasingly restricted or discouraged due to environmental regulations, permitting complexities, and high construction and maintenance costs.

Advanced conductors, such as ACCR, offer a practical alternative. Their high tensile strength and low coefficient of thermal expansion allow them to maintain required ground clearances over long distances without excessive sag. This enables utilities to avoid in-river structures while still meeting reliability and safety standards. Additionally, the high strength-to-weight ratio of these conductors help utilities design lines that can withstand extreme weather events, such as high wind speeds and hurricanes, i.e., conditions that are particularly critical in river crossings where repair access is limited.

Moreover, advanced conductors help maintain tower heights within regulatory limits, including those set by aviation authorities, thereby simplifying the permitting process and reducing the need for excessively tall and costly structures⁶.

1.3.4 Generation Interconnection

The growing demand for electricity, combined with the global push toward a carbon-free energy future, has led to a significant rise in the deployment of new generation resources, particularly renewables such as wind and solar. As these resources are increasingly integrated into the grid, one of the critical

⁶ “One-Year rebuild of a Mississippi river crossing,” *T&D World*, 2023. [Online]. Available: [Link](#).

challenges utilities faces is the need to expand transmission capacity to accommodate the new generation. In many cases, this challenge is addressed using advanced conductors.

Advanced conductors play a key role in generation interconnection by enabling the cost-effective expansion of transmission capacity without requiring new ROW. This is especially important in projects where environmental, regulatory, or land-use constraints limit the construction of new transmission corridors. Through reconductoring, existing transmission lines can be upgraded with higher-capacity conductors, allowing for greater power transfer while maintaining existing infrastructure footprints.

Beyond the ROW limitations, renewable energy integration introduces dynamic and often unpredictable power flows due to the variable nature of generation. These fluctuations can lead to conditions where both normal and emergency (post-contingency) power flows exceed the original thermal ratings of conventional conductors. Advanced conductors, with their higher thermal capacity and resilience to elevated operating temperatures, offer a robust solution to managing these flow conditions.

In this context, the application of advanced conductors is not limited to reconductoring; it also extends to new transmission builds, which are often required to support large-scale renewable generation hubs. Such projects are increasingly incorporated into long-term transmission planning strategies, particularly in regions with aggressive renewable energy goals. Among surveyed utilities, the ACSS conductor is the most commonly used for this purpose. For instance, this is extensively used in the 345 kV Texas Competitive Renewable Energy Zone project. This includes about 3600 miles of new lines to enable 18,500 MW of renewable energy integration.

1.3.5 Reliability and Resilience Improvement

Advanced conductors are increasingly deployed to enhance the reliability and resilience of the electric grid. These applications are driven by the need to meet evolving reliability standards, maintain system redundancy, and withstand extreme weather conditions that pose threats to grid infrastructure. Certain types of advanced conductors, such as the C7 conductor, offer inherent reliability advantages due to their composite carbon cores made of multiple independent strands. This design introduces a level of single-failure tolerance, meaning that the failure of one strand does not result in the failure of the entire conductor. Such properties enhance overall reliability, especially in critical transmission corridors.

Additionally, the low-sag characteristics of many advanced conductors support the long-term reliability of transmission systems by enabling better ground clearance. This is particularly valuable in forested or heavily vegetated areas, where vegetation encroachment is a leading cause of outages and wildfires. By maintaining greater vertical clearances, these conductors reduce the risk of vegetation contact and contribute to fire mitigation efforts. For example, in Minnesota Power's 115 kV Duluth Loop project⁷, new

⁷ "Duluth loop reliability project," *Minnesota Power*. [Online]. Available: [Link](#).

lines are being constructed using advanced conductors to add redundancy and strengthen system reliability in a region prone to extreme weather.

Beyond normal operational reliability, advanced conductors also enhance the resilience of the grid during extreme events, such as hurricanes, ice storms, or wildfires. Their superior mechanical and thermal properties allow them to withstand higher operating stresses, providing crucial benefits such as:

- **Increased loading limits**, enabling lines to carry critical power transfers during emergencies or grid contingencies without exceeding thermal ratings.
- **High tensile strength and flexibility**, improving structural resilience against high wind speeds, dynamic vibrations (such as conductor galloping), and mechanical fatigue.
- **Improved resistance to ice loading and fire damage**, making them suitable for deployment in areas exposed to severe climate conditions.

Overall, the strategic use of advanced conductors is becoming an essential component in modern grid hardening and resilience planning, ensuring not only efficient energy delivery but also the stability and security of the electric transmission system in the face of growing environmental and operational challenges.

1.3.6 Wood Pole Management

In cases where older transmission lines, particularly those built on wooden structures, require upgrades, advanced conductors offer a unique advantage by significantly increasing line ampacity without necessitating the replacement of existing structures. This is especially valuable in situations where ROW limitations, environmental constraints, or clearance requirements restrict the construction of new or more robust structures.

Many legacy transmission lines, particularly those constructed in the mid-20th century, were built using wooden H-frame or pole structures with limited mechanical loading capacity. Traditional conductor upgrades in these scenarios would typically require a complete rebuild with stronger support structures. However, certain types of advanced conductors are engineered to deliver higher current-carrying capacity (ampacity) while maintaining lower weight and comparable or reduced mechanical loading, making them ideal for wood pole management and preservation of aging infrastructure.

A notable example of this application is NV Energy's 2029 upgrade of the Reno–Carson City line. This line was originally built in 1952 with wooden H-frame structures, and it was reconductored using ACCC Linnet-type conductors. This upgrade increased the line's ampacity from 350 A to 1,000 A, without replacing the original structures. The lighter weight and high strength of the ACCC conductor made this possible, whereas a conventional ACSR conductor would have required a full structural rebuild to achieve similar capacity.

1.3.7 Summary of Grid Challenges Addressed by Advanced Conductor

Figure 2 illustrates the extent of adoption of advanced conductors across various utilities in the United States⁸. Figure 3 further provides an assessment of the various applications of advanced conductors, based on findings from two major surveys (a) Idaho National Laboratory (INL), and (b) Electric Power Research Institute (EPRI).

Figure 4 shows a comparison of the various specific applications for which advanced conductors are used, outside of the main goal of transmission capacity expansion.

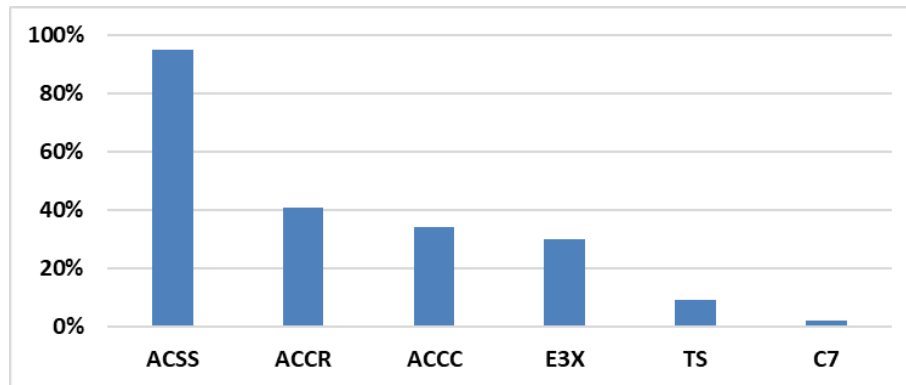


Figure 2(a): Percentage of Selected Utilities Deploying Advanced Conductors.

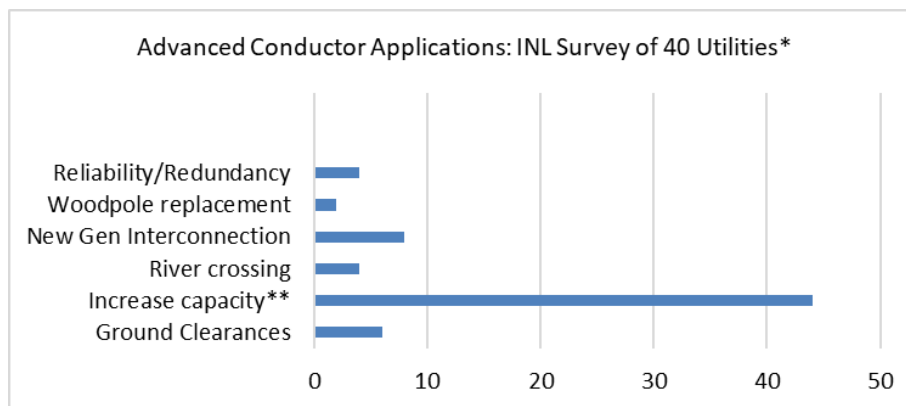


Figure 3(b): Percentage of Selected Utilities Deploying Advanced Conductors.

⁸ "Advanced conductor scan report," *Idaho National Laboratory*, INL/RPT-23-75873, December 2023.

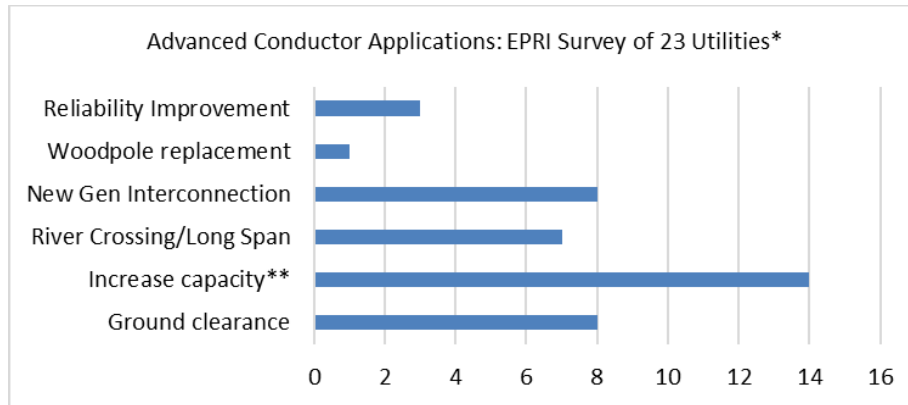


Figure 4: Various Drivers for the Application of Advanced Conductors.

* Some identified projects involve one or more of the applications.

** Increase Capacity includes a myriad of applications intended to resolve thermal violations and congestion challenges.

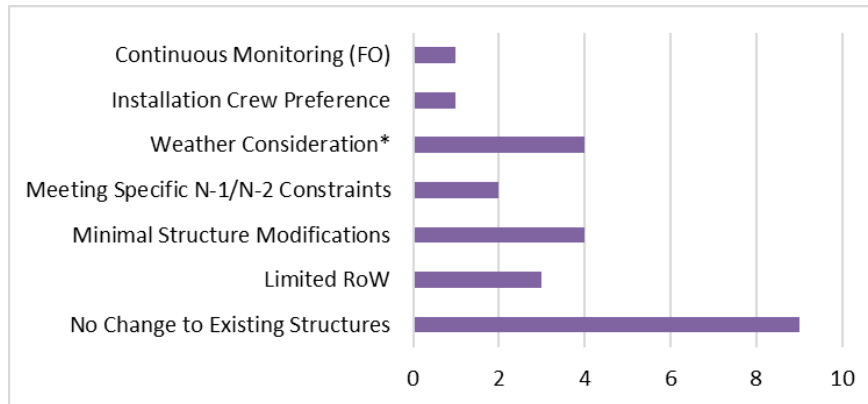


Figure 5: Comparison of Different Specific Applications for Advanced Conductors.

* Weather Considerations include mitigating different factors that affect the conductors due to the weather conditions, e.g., Resistance to wind/ice loading, resistance to vibration (Galloping), fast heat dissipation to reduce losses.

While resolving voltage violations and system stability concerns are not commonly cited as primary drivers for their deployment, these issues are often indirectly mitigated through the core functions that advanced conductors fulfill, particularly those related to thermal violations, congestion relief, and infrastructure optimization. Table 5 summarizes the degree of impact advanced conductors have on addressing various grid reliability challenges.

Table 5: Degree of Impact of Advanced Conductors on Grid Reliability Challenges.

Thermal Violations	Voltage Violations	Stability Violations
Notable	Marginal	Marginal

1.4 Technical and Operational Considerations

The deployment of advanced conductors requires careful evaluation of various technical and operational factors to ensure their optimal application. This section outlines key categories of considerations and highlights implications for utility planning, design, and operation.

1.4.1 Reconductoring vs. New Build Considerations

While advanced conductors are widely used in reconductoring projects, they are also increasingly applied in new transmission line builds. The choice between reconductoring and new construction depends on several critical considerations:

Permitting Concerns/ROW: Permitting and securing new ROWs are often significant barriers to transmission expansion. As ROWs are considered scarce and valuable assets, reconductoring becomes a strategic solution, enabling capacity increases within existing corridors. In such scenarios, the use of advanced conductors is preferred when:

- Capacity must be increased without modifying existing structures
- Mechanical loading is maintained or reduced
- Regulatory and environmental constraints limit the feasibility of new builds

Age and Structural Capacity of Existing Infrastructure: The decision to reconductor (as opposed to a new build) must include consideration for whether the existing structures can support the new conductor material. The key factors to consider include the mechanical loading on towers and the terminal equipment constraint. In some cases, an upgrade of substation equipment is necessary to accommodate the new conductors. Typically, advanced conductors are not used to reconductor old lines, as the infrastructure requires upgrades. New builds are therefore favored in such scenarios.

Cost Considerations: Although the unit cost of advanced conductors is generally higher than conventional alternatives, overall project cost can be significantly lower with reconductoring. Studies and industry use cases have shown that reconductoring projects can cost approximately one-third of a full rebuild. A comprehensive cost-benefit analysis should include:

- Installation and labor costs
- Structure upgrades or reuse
- Delays or savings from permitting processes

1.4.2 Long-Term Planning Implications

Transmission capacity expansion is intended to serve the continuously growing demand on the grid. As such, considerations for deploying advanced conductors must consider their impact on long-term planning needs. For instance, historical ISO/RTO expansion initiatives consider long-term impacts of, among other things, renewable energy integration. It is vital therefore that an appropriate assessment of specific advanced conductors be considered. Areas to be considered include:

- **Load and Generation Forecasts:** Anticipated growth in load and renewable generation affects normal and contingency system operations, which influences conductor selection.
- **Reliability and Performance Over Time:** Advanced conductors must be evaluated for thermal and mechanical durability to ensure sustained performance under dynamic operating conditions.
- **Cost-Effectiveness:** While initial costs may be higher, long-term operational benefits such as reduced losses, increased capacity, and deferred infrastructure investments can provide favorable returns.

1.4.3 Utility-Wide Impacts of Advanced Conductor Deployment

The deployment of advanced conductors introduces a range of technical, operational, and planning considerations across various departments within an electric utility. Each team must evaluate how the characteristics of these modern conductors affect their specific responsibilities. The impacts are both broad and deep, touching engineering design, protection systems, generation interconnection, system planning, and operations.

1.4.3.1 Generator Interconnection

From a generator interconnection perspective, advanced conductors can play a critical role in facilitating the timely integration of renewable energy resources. Due to their enhanced thermal and electrical performance, advanced conductors can help mitigate thermal overloads and clearance violations identified during System Impact Studies (SIS).

Generally, projects implementing advanced conductors can be grouped into three categories, as listed below and summarized in Table 6.

- **Replacement Projects without Tower Upgrades:** In these cases, advanced conductors are used as direct replacements for conventional conductors, with no modifications to existing tower structures. A thorough technical evaluation is necessary to confirm compatibility, particularly with respect to conductor weight and mechanical loading. This approach typically unlocks about 60–70% additional capacity compared to the existing line.

- **Rebuild Projects with Tower Upgrades:** This category involves both the installation of advanced conductors and the upgrading of supporting structures. While this is still more efficient than rebuilding with conventional conductors, advanced conductors allow for greater capacity gains while reducing the need for extensive ROW expansion. Capacity increases in this scenario can reach approximately 150%.
- **New Transmission Line Projects:** In these greenfield projects, advanced conductors are deployed alongside new tower structures and ROW. The improved current-carrying capability of these conductors enables greater transmission capacity within the same corridor, reducing the physical and environmental footprint of the project. Capacity improvements in these cases typically will be more than 150%, depending on system and project characteristics.

Table 6: Summary of Advanced Conductor Implementation Scenarios

Scenario	Infrastructure Scope	Design Considerations	Typical Capacity Increase	ROW Impact
Reconductoring without Tower Upgrades	Existing towers and ROW retained	Weight and mechanical loading compatibility	~60–70%	No change
Rebuild Projects with Tower Upgrades	Existing ROW with upgraded towers	Reduced structural needs compared to conventional rebuilds	~150%	Minimal ROW expansion
New Transmission Line Projects	New towers and new ROW	Greater flexibility in design;	>150%	Reduced ROW needs compared to conventional design

Based on the input received from Indiana utilities, Duke Energy Indiana is evaluating advanced conductors for their sustainability and reliability while developing engineering standards to support the selection of appropriate conductor technologies based on specific transmission needs and application requirements.

1.4.3.2 Transmission Planning

Similar to the generation interconnection, advanced conductors can serve a critical function in transmission planning as an alternative mitigation strategy for thermal violations identified during reliability assessments. Once a thermal violation is identified, the effectiveness of advanced conductors should be evaluated as a potential solution. The applicability of advanced conductors, as outlined in Table 6, can support annual reliability assessments in accordance with IURC’s business practices and NERC TPL-001-5.1 reliability standards.

Based on input received from Indiana Utilities subject matter experts, where a reconductor or rebuild of a transmission line is the recommended solution to an identified transmission need, Duke Energy Indiana considers advanced conductors.

1.4.3.3 System Protection

The enhanced ampacity and thermal ratings of advanced conductors introduce critical changes that must be addressed by the system protection team. These include:

- **Reassessment of Protection Settings:** As line capacities increase, protection schemes such as relay settings and coordination must be reviewed to ensure proper fault detection and system selectivity.
- **Short-Circuit Analysis:** Higher ampacity may influence system short-circuit levels, necessitating a detailed review to ensure equipment ratings (e.g., transformers, breakers) remain within safe operating limits.
- **Breaker and Switchgear Capability:** Circuit breakers and other interrupting devices must be evaluated for their ability to handle new current levels, particularly when reconductoring is performed on existing infrastructure.

1.4.3.4 Operations

Operational teams are responsible for ensuring the real-time and long-term performance of transmission assets. Advanced conductor deployment affects operational practices in several ways:

- **Pre-Deployment Testing:** Utilities often engage in rigorous fields and laboratory testing of advanced conductors to validate performance under expected system conditions. This includes evaluating sag, tension, thermal behavior, and environmental resilience.
- **Conductor Selection:** Operators may need to evaluate several types of advanced conductors to determine which offers the optimal balance of performance, cost, and reliability for a given application.
- **Ongoing Monitoring and Maintenance:** Once deployed, advanced conductors require continued monitoring using technologies such as line sensors and thermal cameras to ensure operational integrity. Maintenance procedures may also evolve to reflect different degradation mechanisms or inspection needs.

1.4.3.5 Engineering and Design (Transmission and Substation)

Among all utility teams, engineering and design, particularly those focused on transmission and substations, are often the most significantly impacted by the adoption of advanced conductors. Key considerations include:

- **Installation Requirements:** Different types of advanced conductors have unique installation characteristics, such as tension limits, handling protocols, and bending radius. These differences require careful planning and procedural updates to ensure safe and reliable installation.

- **Training and Procedure Development:** Installation crews must receive proper training in handling and installing advanced conductors. Enhanced procedures must be developed to mitigate the risk of installation-related failures.
- **Lessons from Industry:** For instance, Duke Energy testified before the North Carolina Utilities Commission in 2022 about their decision to discontinue the use of composite core conductors due to challenges encountered during installation. Similarly, EPRI has noted, based on over 15 years of research, that most failures associated with advanced conductors originate from improper installation practices rather than the technology itself.
- **Structural Assessment and Upgrades:** Engineering teams must also assess whether existing transmission structures, terminal equipment, and associated hardware can support the mechanical and thermal characteristics of advanced conductors. In many cases, structural reinforcement or equipment replacement may be necessary to accommodate new loading or tension requirements.

1.4.3.6 Summary of Utility-Wide Impacts

Table 7 summarizes the impact of advanced conductors across various utility departments.

Table 7: Utility-Wide Impacts of Advanced Conductor Deployment.

Utility Function	Impact Level	Benefits and Considerations of Advanced Conductor
Generation Interconnection	High	Enables timely integration of renewable energy; mitigates SIS thermal and clearance violations; supports flexible upgrade paths.
Transmission Planning	High	Serves as an efficient thermal violation mitigation strategy; supports compliance with NERC TPL standards and IURC planning practices.
System Protection	Low	Requires protection setting updates, short-circuit analysis, and breaker rating assessments to accommodate higher ampacity.
Operations and Control	Low	Involves pre-deployment testing, technology evaluation, and ongoing monitoring/maintenance practices tailored to advanced conductors.
Engineering and Design	High	Significantly affects installation procedures, structural requirements, and training needs; addresses risks from improper installation.

1.5 Best Practice

The deployment of advanced conductors in both the United States and international markets has offered valuable insights into effective selection and application strategies. While each power system has its own unique needs and constraints, several consistent patterns have emerged across successful projects. These common approaches have evolved into industry-recognized best practices, broadly categorized as: upgrading aged infrastructure, river crossings, and new build projects.

1.5.1 Upgrading Aged Infrastructure

In 2021, the American Society of Civil Engineers (ASCE) reported that approximately 70% of transmission and distribution lines in the U.S. were operating in the second half of their 50-year expected lifespan with some assets exceeding 100 years in age. This aging infrastructure presents a significant opportunity for reconductoring with advanced conductors to enhance capacity, efficiency, and reliability. Typical upgrade applications include:

- **Replacing old ACSR conductors** to achieve a higher ampacity-to-load ratio. In many cases, legacy conductors have limited availability of spare parts, making maintenance increasingly difficult and costly.
- **Reconductoring of lines** to achieve higher ampacity while maintaining existing clearances. This approach is particularly common in urban areas, where acquiring new ROW is often impractical due to dense development.
- **Selective reconductoring** of one circuit on a double-circuit tower line, improving capacity while deferring full replacement.
- **Reconductoring long-span lines**, with a focus on maintaining acceptable sag levels at elevated temperatures.

Key evaluation considerations in upgrade projects include:

- **Electrical effect limits** such as electric field strength and audible noise at specific distances, which influence conductor size and configuration.
- **Extensive laboratory testing** of multiple conductor types to validate performance under expected operational conditions.
- **Hardware compatibility**, including the need for custom or additional fittings to accommodate new conductor types.
- **Clearance simulations**, ensuring conductor sag remains within regulatory and design limits across temperature ranges.

1.5.2 River Crossing Applications

As highlighted in Section 1.3.3, river crossings represent a specialized use case where advanced conductors are especially beneficial. These spans are characterized by long distances, stringent clearance

requirements, and limited options for tower height due to environmental or regulatory restrictions near riverbanks. Challenges of river crossings include:

- Long spans that require high mechanical strength.
- Strict clearance limits that must be maintained across varying temperatures.
- Height constraints at tower bases that limits the use of traditional solutions.

Conductor selection criteria typically include:

- **Maximum Tension:** The mechanical limits the conductor can withstand underloading.
- **Maximum Operating Temperature (MOT):** To determine sag and tension characteristics under high current conditions.
- **Sag at MOT:** Critical for maintaining required ground and water clearances.
- **Tower Height Optimization:** Ensuring clearance without necessitating excessively tall or costly structures.

HTLS conductors are often the preferred solution for these applications. It is also common to observe conductor type transitions at river crossings, where one conductor type is used on the approach spans and another across the river. This transition requires careful terminal structure design to manage mechanical and electrical compatibility.

1.5.3 New Build Projects

Advanced conductors are also being utilized in greenfield transmission projects, where developers can fully capitalize on their performance and economic advantages from the start. These projects often integrate advanced conductor technology as a core design feature to meet future energy demands, regulatory targets, and renewable integration goals. Drivers for advanced conductor use in new builds include:

- **ISO Design Preferences:** For example, the Texas Competitive Renewable Energy Zone project adopted ACSS/TW as the preferred conductor after a thorough evaluation, with other composite core conductors deployed in specific segments based on situational needs.
- **Renewable Integration:** New lines designed to connect renewable generation must account for variable power flows and fluctuating output. Advanced conductors help address these challenges through higher ampacity and thermal resilience.
- **Economic Value (Value for Money):** Long-term benefits such as reduced line losses, improved system efficiency, and delayed infrastructure expansion are often found to outweigh the higher initial cost of advanced conductors. Lifecycle cost analysis is commonly used to justify their selection.

1.5.4 Specific Applications and Lessons Learned

In addition to the general best practices categorized in the previous sections, this section highlights real-world applications of some of the most common advanced conductor types. These case studies provide valuable insights into practical deployment considerations and the lessons learned from each implementation.

1.5.4.1 ACSS (Aluminum Conductor Steel Supported)

In the mid-2000s, the Public Utility Commission of Texas and the Electric Reliability Council of Texas (ERCOT) launched the Competitive Renewable Energy Zones initiative, which involved the construction of approximately 3,600 miles of new 345 kV transmission lines. The project aimed to integrate 18,500 MW of renewable generation into the ERCOT system. ACSS conductors were selected as the standard for many segments due to their:

- Low sag at MOT
- Proven operational performance within ERCOT
- High thermal rating
- Cost-effectiveness and market availability

It is notable that for specific segments such as river crossings, where sag and structural concerns were more pronounced, ACCR conductors were used instead.

1.5.4.2 ACCR (Aluminum Conductor Composite Reinforced)

To address an N-2 contingency risk on the Shasta-Keswick 230 kV line, the Western Area Power Administration (WAPA) upgraded the Shasta substation to a double-bus, double-breaker configuration. However, additional improvements were needed to handle post-contingency loading without full structural replacement. WAPA selected ACCR Drake conductors, which enabled:

- Sufficient ampacity increase to handle post-contingency flows
- Minimal sag even at higher operating temperatures
- Avoidance of increased tension, thus eliminating the need for structural reinforcement

The selection of ACCR conductors allowed WAPA to meet system requirements without costly or time-consuming structural upgrades, making it a highly cost-effective solution.

1.5.4.3 ACCC (Aluminum Conductor Composite Core)

American Electric Power (AEP) has implemented advanced conductors in several projects aimed at increasing capacity in dense urban areas where new ROW is unavailable. In one such project in San Antonio, AEP needed to match or exceed the capacity of large ACSR conductors. After evaluating multiple options, ACCC/TW conductors were selected for their:

- High ampacity at the same diameter as existing ACSR
- Trapezoidal-shaped strands (TW), which provide better packing and electrical performance
- Capability to utilize existing structures and ROW, avoiding the need for expansion

This solution balanced capacity increase, ROW constraints, and cost-efficiency.

1.5.4.4 TS Conductor

In 2022, Montana-Dakota Utilities needed to upgrade a 60-mile transmission line between Bismarck and Napoleon, North Dakota, to integrate output from a nearby wind farm. Traditional rebuilding was considered too expensive and time intensive. Instead, the utility adopted a TS conductor, featuring an aluminum-encapsulated carbon core, which:

- Delivered three times the ampacity of the legacy conductor
- Maintained a similar diameter, preserving clearances and avoiding major design changes
- Resulted in 40% cost savings compared to rebuilding with standard ACSR

The high performance and cost-effectiveness of the TS conductor made it a compelling choice for reconductoring in this context.

1.5.4.5 C7 Conductor

In 2014, CenterPoint Energy (CPE) began evaluating C7 conductors to improve system performance in areas constrained by permitting and ROW limitations. CPE typically used ACSR for low-loading lines and ACSS for high-loading ones. For two short 138 kV lines (2.6 and 3.3 miles) in a rural industrial area, CPE tested the C7 conductor, which demonstrated:

- Lower sag than ACSS at high operating temperatures (up to 225°C under emergency conditions)
- Ability to achieve desired capacity without structural upgrades
- Suitability for areas with strict permitting or height restrictions

The trial confirmed that C7 conductors are a valuable alternative where thermal performance and sag control are priorities.

1.5.4.6 E3X Coating

In 2013, Cheyenne Light, Fuel, and Power (CLFP), a subsidiary of Black Hills Energy, constructed a new 115 kV double-circuit transmission line in Cheyenne, Wyoming. Due to unexpected load growth, one circuit quickly reached its capacity limit. CLFP considered reconductoring with ACCC, but to further enhance performance, they applied E3X, a high-emissivity ceramic coating, to the ACCC conductor. This combination resulted in:

- A 116% increase in ampacity, reaching 2057 A
- Improved heat dissipation, enhancing thermal performance
- Reduction in ice accumulation and galloping, which had been problematic with nearby ACSR lines

The E3X coating proved effective in maximizing conductor potential without replacing existing structures.

Table 8 summarizes the different examples identified and the lessons learned.

Table 8: Summary of Advanced Conductor Applications and Lessons Learned.

Technology	Utility Example	Reasons for Utilization
ACSS	ERCOT	• Lower sag at MOT • Proven track record • Higher thermal rating • Cost and availability
ACCR	WAPA	• Lower sag at higher thermal rating • Increased power flow without increases in tension (for post-contingency flow) • Eliminating need for structural modification
ACCC	AEP	• Increased capacity at same diameter • Utilization of existing ROW
TS	Montana-Dakota Utilities	• Significantly higher ampacity at similar diameter • Cost-saving
C7	CenterPoint	• Less sag at high emergency temperatures • Improved performance without structure modification (due to ROW constraints)
E3X	Black Hills Energy/CLFP	• Heat dissipation to improve current-carrying capacity • Prevention of ice-build up and consequent galloping

1.6 Challenges and Barriers

Despite the numerous benefits and successful deployments of advanced conductors across various utilities, several persistent challenges and barriers continue to limit their widespread adoption. These obstacles span technical, financial, operational, and regulatory domains, and require strategic planning and industry collaboration to overcome.

1.6.1 High Initial Cost

As identified in different examples in previous sections, advanced conductors come with higher upfront costs compared to traditional ACSR conductors. This includes costs associated with materials, manufacturing (especially proprietary conductors) and specialized installation equipment. Without clear financial incentives, especially over the long term, this initial investment can serve as a deterrent to their adoption.

1.6.2 Conductor Parameter Testing

Testing advanced conductors presents significant challenges that impede their widespread adoption. This is primarily due to the complexity, duration of required evaluations and in some cases unavailability of pre-existing test data as compared to the traditional ACSR conductor. For example, EPRI provides various kinds of type tests, acceptance tests, routine tests, sample tests, or factory acceptance tests⁹, but these involve several rounds of thermal and cyclic tests to validate its longevity and reliability. These tests are resource-intensive and time-consuming. More so, for utilities, tests by manufacturers on their specific purchase quantity are required beyond general qualification tests. This poses a barrier to the rapid deployment of advanced conductor technology.

1.6.3 Performance Uncertainty in Long-Term Use

Many advanced conductors, particularly composite core types, are relatively newer technologies and lack long-term field performance data. Utilities may be hesitant to invest in these technologies over the long term without clear data on their durability. This is especially likely in areas subject to extreme weather conditions.

1.6.4 Lack of Standardization

A wide variety of advanced conductor technologies exist, offering different current-conducting strands, core materials, coatings, etc. The absence of standardization in their application makes the selection process complex. In this regard, comparison of their performance, cost, compatibility with existing infrastructure introduces different kinds of testing approaches that pose a challenge to utilities.

⁹ “Advanced Conductor Specification Guide,” EPRI, 2024.

1.6.5 Compatibility with Existing Infrastructure

Some advanced conductors require modification or upgrades to existing supporting infrastructure such as tower structures and components. The additional cost required for these upgrades can serve as a barrier especially for reconductoring projects.

1.6.6 Availability and Supply Chain Constraints

The production of some advanced conductors, especially composite core types, is still considered limited. Thus, material availability and manufacturing capabilities can hinder large scale deployment of such conductors. Delays in procurement, high production cost and lack of maintenance materials can hinder their utilization in utilities.

1.6.7 Regulatory and Policy Concerns

Without clear and consistent policy support, utilities may be hesitant to adopt some advanced conductors. Concerns about additional financial or regulatory risks in this case can impact their return on investment. Moreover, regulatory approval for new transmission technologies (including advanced conductors) may be slow or cumbersome. These typically consist of new testing, certifications and safety evaluations.

1.7 Modeling Procedure

The integration of advanced conductors into transmission systems introduces several critical considerations for power system modeling and simulation. These conductors differ significantly from traditional ACSR in terms of electrical and thermal properties, which directly impact system behavior under steady state, short circuit, and dynamic conditions.

1.7.1 Steady State Model

In steady state power flow modeling in PSSE, the line parameters of advanced conductors should be updated, see Figure 5. Also, if the power flow modeling includes temperature-dependent resistance, the increased operating temperatures of advanced conductors (often exceeding 150°C or higher) must be incorporated to accurately simulate line loading.

Branch Data Record

Power Flow | Short Circuit

Basic Data

From Bus Number: 99991 | From Bus Name: BUS A 345.00 | ☒ In Service

To Bus Number: 99992 | To Bus Name: BUS B 345.00 | ☒ Metered on From end

Branch ID: Z | Branch Name:

Branch Data

Line R (pu)	Line X (pu)	Ratings (I as MVA)
0.001760	0.012920	RATE1 1894.0
		RATE2 2081.0
		RATE3 0.0
		RATE4 0.0
		RATE5 0.0

Charging B (pu): 2.142170 | Length: 100 |

Line G From (pu): 0.00000 | Line B From (pu): 0.00000

Line G To (pu): 0.00000 | Line B To (pu): 0.00000

Owner Data

Owner	Fraction
111 Select ...	1.000
0 Select ...	1.000
0 Select ...	1.000
0 Select ...	1.000

OK Cancel

Figure 6: Line Parameters in PSSE Power Flow Model.

1.7.2 Short Circuit Model

Similar to steady-state modeling update, PSSE short-circuit modeling, line parameters need to be revisited to reflect changes introduced by advanced conductor adoption, see Figure 6.

Branch Data Record

Power Flow | Short Circuit

Basic Data

R-Zero (pu): 0.00880

X-Zero (pu): 0.02584

B-Zero (pu): 0.00030

Zero Seq G From (pu): 0.000000 | Zero Seq B From (pu): 0.000000

Zero Seq G To (pu): 0.000000 | Zero Seq B To (pu): 0.000000

MOV Data

MOV Protection Mode: Not a protected branch

MOV Rated Current (kA): 0.00

OK Cancel

Figure 7: Line Parameters in PSSE Short Circuit Model.

1.7.3 Dynamic Model

In transient stability studies, any changes associated with reconductoring may necessitate updates to line parameters, to accurately reflect dynamic performance and damping characteristics. The changes in line parameters will be revised in the power flow models, as mentioned in Steady State Model.

2. Advanced Power Flow Control

2.1 Introduction

Power flow control (PFC) technologies offer a range of solutions for directing electricity more efficiently across the grid, thereby enhancing operational flexibility, responsiveness, and resilience. These technologies are valuable for mitigating overloads and can often delay or eliminate the need for costly grid expansion projects. PFCs are particularly advantageous in scenarios where new transmission lines cannot be constructed due to environmental concerns, land-use restrictions, or regulatory barriers.

In addition to their role in congestion management, PFC technologies support a wide range of applications, including managing unscheduled or loop flows, enforcing contractual or scheduled power transfers, and operational support during system maintenance or construction. Certain PFC technologies are also capable of rapid response to grid contingencies, leveraging the thermal inertia of grid infrastructure to maintain power flows within safe thermal limits during transient events¹⁰.

Advanced Power Flow Control (APFC) refers to modular, power electronics-based devices that regulate power flows on transmission and distribution systems by dynamically adjusting the line reactance where they are installed. Beyond their primary function of power flow regulation, APFC systems also contribute to enhanced voltage and transient stability¹¹.

From a technical standpoint, APFC devices are implemented as modular Static Synchronous Series Compensators (m-SSSCs). These devices inject a voltage that is in quadrature with the line current to emulate either a capacitive or inductive reactance, effectively increasing or decreasing power flow as needed. APFCs utilize Voltage Source Converter (VSC) technology and are built with Insulated-Gate Bipolar Transistors (IGBTs), which are standard in utility-scale VSC applications such as Static Synchronous Compensators (STATCOMs) and High Voltage Direct Current (HVDC) systems¹².

In addition, APFC systems offer sophisticated control functionality, enabling both manual and automated operation modes. These modes allow independent control of the injected voltage regardless of the line current, facilitating real-time variation of the series reactance on the targeted circuit^{10,11}.

Unlike traditional power flow control solutions like phase shifting transformers (PSTs) and fixed series capacitors, APFC systems are modular and voltage-flexible, allowing easy scalability and redeployment. Additional APFC units can be seamlessly added over time or relocated to meet changing system needs. Because APFC deployments typically include multiple devices per phase, they also offer enhanced

¹⁰ A. Rosso, Schweer, D. Schweer, S. Guggilam, J. Gentle, S. Alam, M. Sun, Z. Priest, "Implementation and operation of power flow control solutions for transmission systems," *EPRI and Idaho National Laboratory*, May 2024.

¹¹ A. Rosso, S. Guggilam, A. Lafoyannis, "Advanced power flow control (APFC)," *EPRI*, June 2024.

¹² Smart Wires. [Online]. Available: [Link](#).

reliability. If one device fails, it is automatically bypassed, and the remaining devices continue to function without disruption.

Although APFC offers numerous benefits, including improved grid utilization, congestion mitigation, voltage and stability support, and reduced transmission losses, its widespread adoption is hindered by several challenges. These include limited field deployment experience, compatibility issues with legacy systems, cybersecurity concerns, and hurdles related to regulatory and market acceptance, among others.

2.2 Technology Background

This section presents the foundational principles and technological evolution of PFC systems, with a focus on the development and capabilities of APFC technologies. It begins by reviewing legacy power flow devices, traces the emergence of power-electronics-based solutions, and then describes the core operating mechanisms of modern APFC systems. This background establishes the context for their integration into modern grids and highlights their role in addressing key operational challenges such as congestion, variability, and reliability.

2.2.1 Legacy Power Flow Control Technologies

As power systems become increasingly complex and dynamic, there is a growing need for innovative, flexible technologies that support efficient, reliable, and resilient grid operations. PFC technologies respond to this need by enabling real-time management of transmission line loading, congestion mitigation, and stability enhancement. These solutions leverage power electronics, distributed control architectures, and advanced optimization algorithms to increase the adaptability and responsiveness of modern power networks.

The core function of PFC systems is to regulate the flow of active power along specific transmission paths or across broader grid regions. This regulation is achieved by manipulating key electrical parameters, bus voltage (V), phase angle (δ), or line impedance (Z), which collectively influence line current (I). In most implementations, PFC technologies adjust one of these variables through targeted changes in line reactance (ΔX), phase angle ($\Delta \delta$), or voltage magnitude (ΔV). These local adjustments propagate through the system, producing shifts in voltages and angles across interconnected nodes¹⁰.

The operational effectiveness of a PFC device depends on its installation size, which dictates its setpoint range. For example, PSTs offer a limited angle adjustment, while SSSC or Unified Power Flow Controllers (UPFCs) enable capacitive or inductive voltage injection over a broader range.

In more advanced applications, multiple PFC devices may be deployed in coordination to manage wide-area power flows, particularly during system contingencies or overload events. These scenarios often require centralized control architectures that account for both self-sensitivities and mutual interactions among devices, and that issue coordinated control signals across the fleet. Integrating such centralized

schemes with legacy grid infrastructure introduces significant operational complexity, comparable to that of Special Protection Systems (SPS) or Remedial Action Schemes (RAS)^{10,13}.

2.2.2 Evolution of Power Flow Control Technologies

The control of power flows in AC transmission systems has evolved significantly over the past several decades. Traditional power flow management relied heavily on mechanical or electromechanical devices, such as PSTs and fixed series capacitors. While effective within their operational boundaries, these devices offered limited flexibility, slow response times, and low granularity control. For example, PSTs alter the phase angle between sending and receiving ends to influence power direction, but they are not well-suited for dynamic or automated control schemes.

The introduction of Flexible Alternating Current Transmission System (FACTS) marked a substantial advancement in grid control capabilities. These systems leveraged power electronics to deliver faster, more precise, and continuously adjustable regulation of key transmission parameters. Prominent early FACTS technologies included static VAR compensators, thyristor-controlled series capacitors (TCSCs), and SSSCs. FACTS devices improved system stability, voltage regulation, and transfer capacity. However, their adoption has been limited by high capital costs, complex installation requirements, and integration challenges with legacy infrastructure. Moreover, many early FACTS systems were designed as centralized or rigid solutions, reducing scalability and adaptability in evolving grid environments¹⁴.

In recent years, APFC technologies have emerged as a next-generation solution, addressing many of the shortcomings of legacy FACTS devices. APFC systems are typically modular, voltage-flexible, and software-controlled, offering real-time, distributed control of transmission line impedance. These systems use VSCs built with semiconductor components such as IGBTs, enabling fast and accurate modulation of power flows in response to grid dynamics.

One of the key innovations in APFC is its ability to provide adaptive impedance control across multiple network locations with minimal infrastructure disruption. This modularity allows utilities to incrementally deploy, scale, or relocate APFC units as system needs evolve, enhancing both cost-effectiveness and operational flexibility. Furthermore, APFC technologies are well-suited for integration with modern control architectures, including centralized and distributed optimization algorithms, Supervisory Control and Data Acquisition (SCADA) systems, and advanced energy management systems (EMS).

The shift toward APFC reflects a broader trend in power system modernization, emphasizing digitalization, resilience, and renewable integration. As power grids face increasing uncertainty due to variable generation, dynamic loads, and stricter reliability requirements, APFC offers a practical toolset for

¹³ S. Imdadullah, M. Amrr, M. Asghar, I. Ashraf, M. Meraj, "A Comprehensive Review of Power Flow Controllers in Interconnected Power System Networks," *IEEE Access*, 2020.

¹⁴ "Unified power flow controller (UPFC PLUS®)," *Siemens Energy*, 2025. [Online]. Available: [Link](#).

congestion management, loss reduction, and improved asset utilization¹⁵. Figure 7 shows a conceptual illustration of how APFC devices alleviate transmission congestion by dynamically redistributing power flows across the grid.

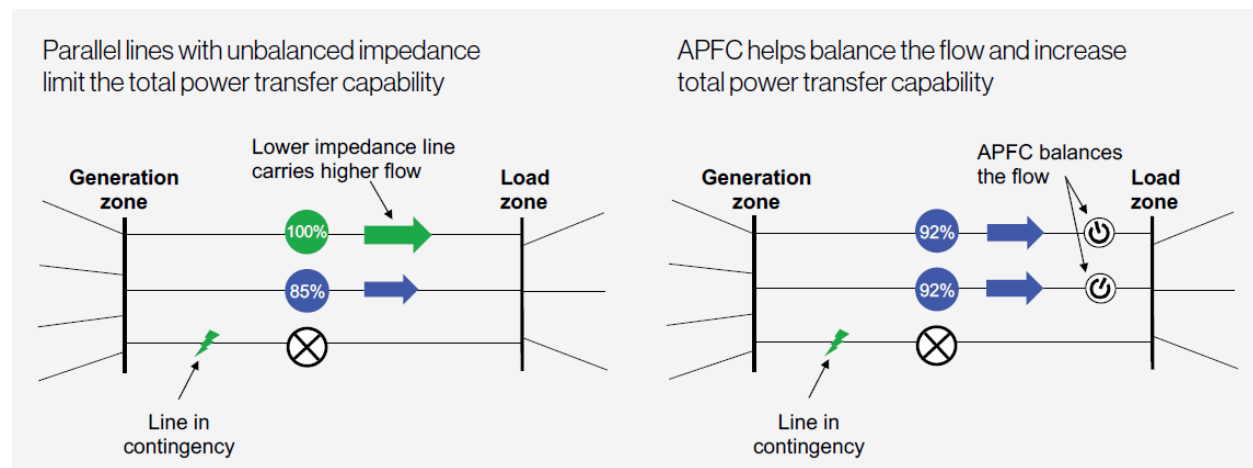


Figure 8: Visual Concept of Impact of APFC Devices on Congestion Management.

2.2.3 Technical Mechanisms of Power Flow Controllers

Power electronics-based APFCs represent a transformative approach to managing active and reactive power flows across transmission networks. Unlike traditional mechanical or fixed compensation methods, these technologies leverage semiconductor-based control systems to dynamically influence line parameters such as impedance, voltage magnitude, and phase angle. This capability enables fast, precise, and modular power flow adjustments that can be tailored to real-time grid conditions. The following subsections detail key APFC technologies and their respective operational mechanisms.

Power Electronics-Based Series Compensation: One of the most commercially mature implementations of power flow control is power electronics-based series compensation, exemplified by technologies like Smart Wires' *SmartValve*. These devices use semiconductor switches, typically based on IGBTs, to inject a controllable series reactance into transmission lines. By modifying the effective impedance of a line segment, these devices redirect power flows away from congested paths and toward underutilized transmission corridors. The rapid response time and low power loss characteristics of such systems make them highly effective for real-time congestion relief and dynamic reconfiguration of network flows.

¹⁵ "Advanced power flow controllers grid enhancing technologies: technical reference guide," *PJM*, 2024.

Distributed Flexible AC Transmission Systems (D-FACTS): D-FACTS build upon the principles of series compensation by deploying an array of low-power compensation modules along a transmission line. Each module modulates line reactance locally, and together they form a coordinated system that offers high spatial resolution for flow control. This distributed architecture enhances redundancy and fault tolerance, as individual unit failures do not compromise system-wide functionality. D-FACTS devices can be operated in both autonomous and coordinated modes. In centralized control configurations, system-level optimization algorithms aggregate real-time sensor data to issue global commands that maximize network efficiency and minimize congestion.

Unified Power Flow Controller (UPFC): The UPFC is considered the most versatile and functionally comprehensive member of the FACTS family. Developed to regulate all three power flow variables, voltage magnitude, phase angle, and line impedance, the UPFC enables direct and simultaneous control of both active and reactive power flows in a transmission line. The UPFC architecture consists of two VSCs connected back-to-back via a common DC link. One converter is connected in shunt to provide or absorb reactive power and maintain the DC link voltage, while the other is connected in series with the transmission line to inject a controllable AC voltage. This voltage is injected into quadrature with the line current, enabling precise manipulation of power flows.

The first major deployment of a UPFC, a 160-MVA installation by American Electric Power (AEP) at the Inez Substation in Kentucky in 1998, demonstrated the device's ability to significantly enhance transmission capacity and system stability. Today, UPFCs are viewed as benchmark solutions for multi-parameter control, particularly in regions with high renewable penetration and frequent congestion^{16,17,18}.

Interline Power Flow Controller (IPFC): While the UPFC focuses on optimizing flow on a single transmission line, the IPFC extends this concept to manage power flow across multiple lines that are electrically connected at a common substation. A typical IPFC setup includes two or more series-connected VSCs, each installed on a separate transmission line, and all sharing a common DC link. This configuration allows real power to be transferred between lines via the DC link, effectively redistributing power from heavily loaded lines to those with spare capacity.

Each VSC in the IPFC also provides independent reactive compensation, allowing for tailored control of individual line flows. The dynamic interaction among VSCs enables the IPFC to manage both local and system-wide constraints, reduce line overloads, and improve voltage stability across a broader network

¹⁶ L. Gyugyi, C. Schauder, S. Williams, T. Rietman, D. Torgerson, A. Edris, "The unified power flow controller: A new approach to power transmission control," *IEEE Transactions on Power Delivery*, April 1995.

¹⁷ L. Liu, P. Zhu, Y. Kang, and J. Chen, "Power-flow control performance analysis of a unified power-flow controller in a novel control scheme," *IEEE Transactions on Power Delivery*, July 2007.

¹⁸ A. Rajabi-Ghahnavieh, M. Fotuhi-Firuzabad, M. Shahidehpour, R. Feuillet, "UPFC for enhancing power system reliability," *IEEE Transactions on Power Delivery*, October 2010.

area. The IPFC is particularly beneficial in complex meshed networks where multiple interdependent constraints need to be resolved simultaneously ^{19,20,21}.

2.3 Applications and Benefits

APFC technologies are transforming how transmission systems are planned and operated. By providing real-time control over power flows, these devices enable utilities to better utilize existing infrastructure, address congestion, manage system variability, and respond adaptively to evolving grid demands. The following subsections summarize key applications and benefits of APFC deployment across a range of operational and planning contexts.

2.3.1 Core Applications and Strategic Benefits

This subsection outlines the core applications and system-level benefits of APFC deployment across today's increasingly complex transmission networks, followed by a summary of grid challenges addressed by APFC in Table 9.

Increasing Transmission Capability: APFC devices unlock underutilized capacity in existing transmission corridors by rerouting power flows away from congested elements. This capability helps boost power transfer into constrained areas, such as urban load centers, without requiring new infrastructure. APFC systems are modular and scalable, allowing for incrementally deployment to address near-term reliability needs and support phased expansion strategies.

Reducing Transmission Congestion: By dynamically managing power flow, APFC devices relieve congestion on overloaded lines, reducing reliance on costly redispatch and minimizing curtailment of lower-cost or renewable generation. They provide a cost-effective alternative to large-scale upgrades, with faster deployment timelines and fewer permitting challenges. Studies have shown their potential to save consumers hundreds of millions in congestion-related costs.

Mitigating Unscheduled (Loop) Flows: Loop flows, which result from unintended power paths due to impedance imbalances, can cause stress on adjacent systems and market distortions. APFC technologies allow operators to align physical flows with contractual paths, reducing cross-border impacts and maintaining operational control across regional seams. This control is especially valuable in highly interconnected grids.

¹⁹ S. Teerathana and A. Yokoyama, "An optimal power flow control method of power system using interline power flow controller (IPFC)," in *Proc. IEEE Region 10 Conf. TENCON*, May 2005.

²⁰ K. Padiyar and N. Prabhu, "Analysis of SSR with three-level twelve pulse VSC-based interline power-flow controller," *IEEE Transactions on Power Delivery*, July 2007.

²¹ N. Santos, O. Dias, V. Pires, "Use of an interline power flow controller model for power flow analysis," *Energy Procedia*, 2012.

Enforcing Contractual Power Flows: In markets with complex interconnections, APFC devices provide operators with tools to direct flows along agreed-upon paths, ensuring fairness and compliance. APFC systems have been used to manage large interregional transfers, such as between PJM and NYISO, helping to protect system reliability and uphold market integrity while reducing wear on mechanical equipment.

Addressing Short-Term Operational Challenges: Temporary grid constraints, caused by outages, delays, or construction, can threaten reliability. Rapidly deployable APFC units offer a flexible response, restoring system margins without relying on expensive short-term fixes. Their reusability enhances long-term value, as units can be relocated and reused across multiple projects or regions as system needs evolve.

Enabling Flexible and Adaptive Expansion: Uncertainty around future grid needs makes rigid infrastructure investment risky. APFC technologies support adaptive planning by enabling staged, modular deployment. Utilities can meet current reliability standards while preserving optionality for future upgrades, reducing the risk of stranded assets and ensuring that investments are aligned with actual system growth.

Improving Oscillation Damping and Grid Stability: Certain APFC devices, such as SSSCs, help damp inter-area oscillations by adjusting line impedance in real time. This improves system dynamic response and enhances overall stability, particularly in large or renewable-rich networks where variability and weak interconnections can otherwise challenge secure operation.

Providing SSR-Immune Series Compensation: Unlike traditional series capacitors, some APFC technologies do not introduce sub-synchronous resonance (SSR) risks. Their power electronics-based design allows for controllable series compensation without compromising generator shaft integrity, making them especially useful for long-distance corridors where SSR is a concern.

Deferring Infrastructure Upgrades: One of APFC's most valuable roles is delaying or avoiding major infrastructure projects by optimizing existing grid assets. In doing so, APFC devices provide time for better planning, clearer forecasting, and coordination with broader system improvements. This is especially important in uncertain environments, where premature investment in permanent infrastructure could prove inefficient or unnecessary.

Complementing Other ATTs: APFC devices work together with tools like Dynamic Line Rating (DLR), topology optimization, and advanced forecasting systems. For example, DLR may identify headroom on a line, but APFC is needed to route power there. This combination enables more intelligent, responsive grid operation and maximizes the value of ATT investments.

Table 9: Summary of Grid Challenges Addressed by APFC.

Grid Challenge	APFC Mitigation Strategy	Example / Explanation
Thermal Overloads (Congestion)	Redirects power flow from overloaded to underutilized lines via real-time impedance control	Alleviates bottlenecks in urban corridors without new line construction
Loop (Unscheduled) Flows	Aligns physical flows with scheduled contracts by managing impedance and phase shifts	Reduces stress on neighboring systems and market distortions at regional seams
Inter-Area Oscillations	Modulates impedance to provide damping for dynamic instabilities	Stabilizes systems with high renewable penetration or weak interconnections
Contingency Management	Enables corrective or preventive control modes to maintain safe operation during outages	Ensures reliability under N-1 and some N-2 conditions through real-time adjustments
Contractual Flow Enforcement	Directs power along agreed-upon paths to support market fairness and planning accuracy	Commonly used in interregional transfers like PJM–NYISO
Short-Term Grid Support During Construction/Outages	Deployable in modular form to temporarily mitigate constraints	Used during maintenance or delays in traditional upgrades
Infrastructure Upgrade Deferral	Delivers near-term performance gains without major capital investment	Time for planning larger-scale reinforcements
Renewable Integration	Relieves congestion to enable interconnection of variable generation sources	Unlocks capacity for wind/solar without building new lines
Coordination with Other ATTs	Complements DLR, topology optimization, and forecasting tools	DLR identifies headroom; APFC routes power to utilize it

2.3.2 Effects on Various Types of Grid Violations

APFC technologies offer targeted solutions to a broad range of reliability challenges in transmission systems. By dynamically adjusting power flow paths, these devices support real-time and planned operations, reduce violations, and enhance overall system security. Their impact can be categorized according to the three primary classes of reliability violations: thermal, voltage, and stability.

2.3.2.1 Thermal Violations

APFCs mitigate thermal overloads by redirecting power from constrained lines to underutilized corridors. Through discrete or continuous operating settings, they adapt to changing system conditions throughout the day, reducing congestion costs and increasing access to more economical generation resources.

In addition, APFCs mitigate unscheduled flow. Unscheduled (or loop) flows result from the inherent electrical behavior of meshed networks, where actual flows deviate from scheduled transactions. APFCs help manage these flows by realigning real power transfers with contract paths. Effective control requires

consideration of APFC's sensitivity to the target line, flow impacts on neighboring balancing areas, and internal system redistributions. These adjustments reduce regional conflicts and congestion caused by unintended cross-border flows.

Furthermore, in systems with complex interconnections and structured power markets, multiple APFCs can be coordinated to ensure that energy transfers follow designated contract paths. This alignment promotes market fairness, reduces the risk of overloading unintended lines, and improves planning accuracy.

2.3.2.2 Voltage Violations

Some APFC devices are capable of injecting or absorbing reactive power, helping to maintain voltage levels within acceptable limits. By addressing local or regional voltage concerns, APFCs support both normal operations and voltage recovery following disturbances.

2.3.2.3 Stability Violations

APFCs enhance system stability through:

- **Operational Resilience:** APFCs enhance resilience by providing operators with tools to manage dynamic conditions during normal and emergency states. Their ability to respond in real-time makes them valuable during fast-changing system events.
- **System Stress Alleviation:** By redistributing power away from stressed components, APFCs lower the overall burden on critical infrastructure. This not only helps prevent violations but also extends equipment life and improves asset utilization.
- **Dynamic Stability Enhancement:** Certain APFCs, such as SSSCs, can modulate line impedance in real time, providing damping for inter-area oscillations and improving the dynamic performance of the grid.
- **Contingency Management:**
 - **Preventive Control:** APFCs can be pre-set to create operational headroom in anticipation of potential contingencies. This conservative strategy reduces grid utilization under normal conditions but provides security margins for emergency response.
 - **Corrective Control:** Event-specific adjustments are made after a disturbance occurs. This approach is more efficient, as it responds only when needed, allowing for higher grid utilization and lower operational constraints.

With the growing adoption of real-time contingency analysis (RTCA), operators can leverage APFCs in both preventive and corrective modes, enhancing situational awareness and response precision.

2.3.2.4 Summary of Grid Challenges Addressed by APFC

Table 10 summarizes the degree of impact APFCs have on addressing various grid reliability challenges:

Table 10: Degree of Impact of APFCs on Grid Reliability Challenges.

Thermal Violations	Voltage Violations	Stability Violations
Notable	Marginal	Marginal

2.4 Technical and Operational Considerations

While the strategic and economic advantages of APFCs are well-documented, their successful deployment hinges on careful technical and operational planning. Effective integration of these technologies requires a comprehensive understanding of system needs, robust implementation strategies, and cautious cybersecurity measures. This section investigates the critical considerations for implementing APFCs, encompassing technology assessment, operational coordination, and resilience against cyber and physical threats²².

2.4.1 Technology Implementation Assessment

Implementing APFCs begins with a thorough needs assessment to identify optimal deployment strategies that align with grid requirements. Transmission planners must evaluate various factors, including device placement, sizing, and integration with existing infrastructure. A comprehensive cost-benefit analysis is essential, considering not only the capital and operational costs but also the potential for deferred infrastructure investments and enhanced system reliability.

Moreover, planners should consider the compatibility of APFCs with other grid technologies and the scalability of solutions to accommodate future system expansions. Engaging stakeholders early in the planning process ensures that the selected technologies meet regulatory requirements and operational objectives. By adopting a systematic approach to the implementation of technology, utilities can maximize the benefits of APFCs while mitigating potential risks.

2.4.2 Operation and Control Considerations

The operation of APFCs varies based on the application, ranging from autonomous local control to more complex centralized coordination. In simple configurations, such as mitigating overloads or maintaining line flow within a set bandwidth, a single APFC can operate independently. The device uses real-time line measurements to adjust power flows based on operator-defined setpoints. This approach is common in North America, where PSTs and similar devices are used to manage contracted power flows without the risk of control conflicts when devices act in isolation.

²² A. W. Abboud, et al. "A guide to case studies of grid enhancing technologies," *Idaho National Laboratory*, 2022.

For system-wide applications involving multiple APFC units, centralized coordination becomes necessary to ensure harmonized device performance. This requires control centers to manage setpoints collectively while accounting for both individual and mutual sensitivities among devices. Although such schemes increase operational complexity and demand tighter integration with existing control systems, they offer significant benefits in terms of flexibility, reliability, and grid efficiency, especially under dynamic or contingency conditions.

2.4.3 Cyber and Physical Threats Considerations

As APFCs become increasingly integrated into grid operations, ensuring their resilience against cyber and physical threats is paramount. These devices, being part of the broader cyber-physical system, are susceptible to a range of security challenges, including malware, ransomware, and advanced persistent threats. A successful attack could lead to service disruptions, equipment damage, or compromised data integrity.

To mitigate these risks, utilities must implement robust cybersecurity frameworks that encompass real-time monitoring, anomaly detection, and incident response protocols. Regular security assessments and updates to control systems are essential to address emerging vulnerabilities. By prioritizing security considerations in the deployment of APFCs, utilities can safeguard critical infrastructure and maintain reliable grid operations²³.

2.4.4 Utility-Wide Impacts of APFC Deployment

The integration of APFCs affects key areas within a utility, including generation interconnection, transmission planning, system protection, operations, and engineering design. A comprehensive understanding of the role and impact of APFCs across utility departments is essential for effective deployment, operational reliability, and long-term system planning. This section outlines the specific considerations each department must account for when integrating APFCs into the power grid.

2.4.4.1 Generation Interconnection

From a generation interconnection perspective, APFCs can play a critical role in accelerating the integration of renewable energy resources. By optimizing the use of existing transmission assets and redirecting power flows, APFCs might reduce the need for extensive infrastructure upgrades that often delay interconnection timelines.

Once an overload is identified in a system impact study (SIS), as part of evaluating a single generation interconnection request or a cluster interconnection request, the effectiveness of APFC should be evaluated to mitigate the overload. In cluster study, APFC mitigation assessment should be performed in “Study Case with Priors”, where requested generating facilities in cluster are dispatched at maximum

²³ H. Ishii and Q. Zhu, “Security and resilience of control systems - theory and applications,” *Springer Cham*, 2022.

output unless Power Transfer Distribution Factor (PTDF) is less than a pre-determined values, e.g., 5% in TRANS-SPP-07.010.

Here are some insights that may be useful during the APFC development in a generation interconnection process under NERC Categories P0-P7 contingencies:

- For violations that appeared in the normal system condition (i.e., NERC category P0), APFC is generally not an optimal solution for resolving overload violations, as it may introduce additional overload violations when the system is stressed under contingency conditions.
- For violation caused by NERC categories P1-P4 and P7, APFC may be a feasible solution if all the following conditions are met:
 - Each overloaded facility does not operate in a radial configuration under post-contingency conditions.
 - Only one facility is overloaded, or if multiple facilities are affected, then they all belong to the same transmission corridor.
 - At least one alternative path exists with enough capacity to accommodate the additional power transfer.
 - The APFCs do not introduce new overloads.
- At extra high voltage levels (i.e., 300 kV and above), APFCs may be impractical due to limited available capacity in parallel corridors. Additionally, multiple APFC units might be needed to address the violation, which should be evaluated against other possible solutions.
- For violations caused by NERC category P5 contingencies, APFCs may not be a cost-effective solution, as addressing redundancy through protection system enhancements is typically the most straightforward approach.
- For violations caused by NERC category P6 contingencies, the allowable load drop or generation dispatch limit is typically high. If the threshold exceeds this limit, the amount of power that must be redirected to other corridors can be significant, making APFC an impractical solution.
- APFC may be a feasible solution for mild to moderate overload conditions on transmission lines with lower ratings.

In addition, the scalability and flexibility in use of APFCs make them ideal for supporting phased development strategies that align infrastructure investment with actual in-service date of the interconnection requests. Rather than committing to large-scale capital projects with long lead times, APFCs can be deployed to address current needs while preserving future flexibility.

2.4.4.2 Transmission Planning

Similar to their role in generation interconnection, APFCs can serve a critical function in transmission planning as an alternative mitigation strategy for thermal violations identified during reliability assessments. By redirecting power flows and utilizing available transmission capacity headroom, APFCs may reduce or delay the need for extensive infrastructure upgrades.

Once a thermal violation is identified, the effectiveness of APFCs should be evaluated as a potential solution, to support annual reliability assessments in accordance with IURC’s business practices and NERC TPL-001-5.1 standards. APFCs development process insights mentioned in Section 2.4.4.1 (items a-f) also applies to transmission planning.

Moreover, the scalability and flexibility in use of APFCs make them particularly well-suited for phased development strategies that align infrastructure investments with project in-service timelines. Rather than committing to large-scale capital investments with long lead times, utilities can deploy APFCs to address immediate needs while maintaining future flexibility. This approach is especially beneficial in large load interconnection scenarios, such as data centers.

2.4.4.3 System Protection

System protection engineers must evaluate how APFCs interact with protection schemes to ensure system security under all operating conditions. A mis-operation or failure of a power flow controller could have significant consequences, including violations of thermal, voltage, or stability limits. Protection settings may need to be adjusted to accommodate altered power flow patterns introduced by APFCs, especially in systems where directional relays or distance protection schemes are sensitive to impedance changes. Coordination with RAS and SPS is also crucial to prevent unintended interactions. As APFCs are incorporated into the grid, protection strategies must evolve to maintain selectivity, dependability, and security, all while accommodating more dynamic and bidirectional power flows.

2.4.4.4 Operations and Control Systems

The integration of APFCs into grid operations introduces new layers of complexity, particularly when multiple devices are deployed across the system. While single APFCs can operate autonomously based on local measurements, broader deployments may require centralized control schemes that coordinate setpoints across all devices. This coordination must account for both self-sensitivities and mutual interactions, necessitating enhanced modeling capabilities and robust operator interfaces. Moreover, operators and planners express justified concerns over the limited industry experience with large-scale APFC coordination, and the potential operational risks associated with control scheme failure or misconfiguration. These considerations are also reflected in stakeholder responses received from Indiana utilities, including Duke Energy Indiana and Hoosier Energy, which highlighted protection coordination and operational implications associated with APFC deployment.

To mitigate these risks, APFC control schemes must be designed with attributes such as dependability, security, selectivity, robustness, adaptability, and performance. Effective training and simulation tools are also needed to build operator familiarity and confidence.

2.4.4.5 Engineering and Design

From a transmission and substation engineering standpoint, APFCs offer a practical and cost-effective solution to maintain grid reliability amid project delays or phased development. Their modular nature allows for rapid deployment, often with shorter permitting and construction timelines compared to traditional reinforcements. APFCs can serve as interim solutions that bridge the gap between immediate

operational needs and long-term infrastructure build-outs. Engineering teams must consider site-specific requirements, such as footprint, interconnection points, and compatibility with substation equipment and protection systems. In some cases, APFCs can even defer or eliminate the need for permanent upgrades, improving project sequencing and capital efficiency. To optimize deployment, coordination with planning and operations teams is essential to ensure seamless integration and alignment with broader system objectives.

2.4.4.6 Summary of Utility-Wide Impacts

Table 11 summarizes the impact of APFCs technology across various utility departments.

Table 11: Utility-Wide Impacts of APFC Deployment.

Utility Function	Impact Level	Primary Benefits/Impacts of APFC Deployment
Generation Interconnection	High	Mitigates thermal violations in a SIS, accelerates renewables integration, supports phased build-out
Transmission Planning	High	Alternative to early reconductoring or re-build, enables adaptive planning, delays capital-intensive upgrades; provides a feasible solution for some of the violations observed during long-lead transmission equipment sensitivity studies.
System Protection	Medium–High	Alters impedance paths; requires relay coordination; improves protection adaptability in dynamic grids
Operations and Control	High	Enables autonomous and coordinated control; supports contingency response; improves flow flexibility
Engineering and Design	High	Modular deployment with lower footprint; shortens construction timelines; aligns with evolving site needs

2.5 Best Practice

This section highlights leading practices in the deployment of APFC technologies, with a particular focus on Smart Wires’ SmartValve, a modular and scalable APFC device that has been successfully implemented by utilities worldwide. Utilities across Europe, the United States, Latin America, and Australia are increasingly leveraging SmartValve™ to unlock latent transmission capacity, relieve congestion, and enhance grid flexibility.

The relevance of APFC solutions continues to grow, particularly considering evolving regulatory frameworks. In the United States, the Federal Energy Regulatory Commission (FERC) has reinforced the importance of ATTs through new directives. FERC Order No. 1920²⁴ mandates the inclusion of APFC and

²⁴ “FERC Docket No. RM21-17-00; Order No. 1920: building for the future through electric regional transmission planning and cost allocation,” *FERC*, 187 FERC 61,068, May 2024.

other ATTs in long-term regional transmission planning processes, while FERC Order No. 2023²⁵ requires transmission providers to evaluate the use of APFC technologies as part of interconnection studies. These regulatory developments underscore the need for utilities to incorporate APFC devices not only as a reliability tool, but as a strategic asset in modern grid planning and operations.

The following subsections provide a closer look at how APFC technologies are being implemented in real-world utility environments, highlighting use cases, deployment strategies, and lessons learned.

2.5.1 United States Deployments and Best Practice Projects

In the United States, APFC technologies, particularly Smart Wires' SmartValve™, are being deployed across various regions to enhance grid reliability, alleviate congestion, and facilitate the integration of renewable energy sources. Below are notable projects exemplifying the application of APFC.

Vermont Electric Power Company (VELCO): VELCO has deployed SmartValve technology at the existing Sand Bar Station to address operational challenges caused by increasingly variable power flows, which are largely driven by rising levels of renewable energy integration. The primary issue was excessive tap changes in the station's PSTs, which had previously failed and resulted in a lengthy outage and complex replacement process.

To resolve this, VELCO installed twelve SmartValve modules in series with the existing PST. This APFC deployment helps stabilize the flow of electricity, significantly reduces unnecessary tap changes, and extends the operational life of the PST. The SmartValve was selected as the most cost-effective and efficient solution due to its precision control capabilities, short lead time, and technological diversity compared to alternative options.

The installation requires a modest expansion of the substation footprint to accommodate SmartValves, associated bus work, and instrument transformers. Additional work includes installing three motor-operated load break switches, relocating two sections of the existing 115 kV transmission line, and clearing vegetation to allow for equipment access and environmental management. A new access driveway will also be constructed to support the project's implementation.

Central Hudson Gas & Electric: In support of New York State's clean energy goals, targeting 70% renewable electricity by 2030, the NYISO identified a need to increase the transfer capacity of the UPNY–SENY interface by 185 MW. Central Hudson Gas & Electric explored several network upgrade options, including fixed series capacitors, but ultimately selected SmartValve as the preferred solution based on cost-effectiveness, speed of deployment, and operational flexibility.

In 2023, fifteen SmartValve units (10 MVar each) were installed on the 345 kV Leeds–Hurley Avenue circuit. These devices enable real-time control of power flows, allowing operators to redirect power onto

²⁵ "FERC Docket No. RM22-14-000; Order No. 2023: improvements to generator interconnection procedures and agreements," *FERC*, 184 FERC 61,054, July 2023.

underutilized transmission paths. The SmartValve deployment successfully unlocked the targeted 185 MW of additional capacity.

This approach required significantly less substation modification than fixed series capacitors and had a 25% smaller footprint, resulting in an estimated \$10 million cost savings. Central Hudson Gas & Electric also noted additional benefits, including a reduced risk of sub-synchronous resonance and the ability of SmartValve to provide dynamic services such as enhanced voltage and transient stability.

Avista Utilities and Idaho Power: Avista Utilities and Idaho Power are jointly leading a major APFC project aimed at increasing interregional transfer capability between the Pacific Northwest and Mountain regions. The project centers on the reconstruction of the Lolo–Oxbow 230 kV transmission line using wildfire-resilient designs, alongside the deployment of SmartValve devices to actively balance power flows across neighboring transmission lines.

Instead of rebuilding multiple lines, this solution focuses on the construction of a single 230 kV corridor, using the SmartValve technology to ensure the optimal and full utilization of the enhanced line. This approach significantly reduces construction complexity and environmental impact.

The project is expected to increase interregional transfer capacity by approximately 635 MW, strengthening system reliability and benefiting hundreds of thousands of customers across Washington, Idaho, and Oregon. It will also support the Nez Perce Tribe in developing renewable energy resources by enabling new generation interconnections on tribal lands. Additional operational benefits include reducing unplanned line outages to fewer than one per year and minimizing reconstruction disruptions by using drones for line stringing.

2.5.2 International Deployments and Best Practice Projects

APFC technologies, particularly Smart Wires' SmartValve, are being adopted globally to enhance grid reliability, alleviate congestion, and facilitate the integration of renewable energy sources. The following projects illustrate the diverse applications and benefits of APFC across various regions.

ISA ENERGIA BRASIL – São Paulo, Brazil: ISA ENERGIA BRASIL is implementing Brazil's first large-scale APFC project by deploying SmartValves in São Paulo State. This initiative aims to address immediate overload issues and provide long-term power flow control capabilities. The project involves installing SmartValves on two circuits to unlock capacity for an immediate load increase near Ribeirão Preto. Once the reconstruction is completed in 2027, the SmartValves will be relocated to the São José do Rio Preto and Votuporanga substations. The modular nature of SmartValves allows for future expansion as power flow control needs increase.

ISA TRANSELCA – Atlántico Region, Colombia: In the Atlántico region, ISA TRANSELCA has deployed SmartValves across five 220 kV circuits, unlocking over 300 MW of additional transmission capacity. This deployment supports the integration of 1.5 GW of approved wind and solar generation projects. The SmartValves are uniquely installed indoors at the Nueva Barranquilla substation to withstand the corrosive

coastal environment. This project exemplifies how strategic investments in APFC technologies can optimize grid capabilities and expedite the adoption of renewable energy.

Empresas Públicas de Medellín (EPM) – Aburrá Valley, Colombia: EPM pioneered the use of SmartValve technology in Latin America with a pilot project in 2021 at the Envigado 110 kV substation. Following its success, EPM expanded the deployment in 2022 by installing 12 SmartValves across three 110 kV transmission lines in the Aburrá Valley. This expansion unlocked capacity for over 400 MW of small hydroelectric power plants, addressing forecasted demand growth. The project demonstrated the flexibility and scalability of SmartValve technology in enhancing grid reliability and supporting renewable energy integration.

Grupo Energía Bogotá (GEB) – Cartagena, Colombia: GEB implemented the SmartValve technology at the Termocandelaria substation in Cartagena to alleviate inter-regional congestion and unlock 252 MW of new capacity for generation on the existing network. This deployment enhances the availability of energy to meet demand, improves reliability of supply, and supports economic development in the region. By optimizing existing infrastructure, GEB avoided the need for new transmission projects, demonstrating the environmental and economic benefits of APFC solutions.

Independent Power Transmission Operator (IPTO) – Nea Santa, Greece: As part of the FARCROSS project, Greece's IPTO deployed SmartValves on the 150 kV Nea Santa–Iasmos line. This deployment aimed to manage cross-border power flows and support renewable energy integration in a region with high wind power generation. The SmartValves effectively redirected power flows, influencing the adjacent 400 kV Greece–Turkey interconnector and demonstrating the technology's potential in enhancing cross-border electricity transfers and integrating renewable energy sources.

Amprion – Germany: Amprion, the German transmission system operator, conducted a pilot project to test the SmartValve technology for optimizing grid loading. The study concluded that SmartValves effectively distribute power flows more evenly across circuits, increasing line utilization and contributing to system stability. Amprion found no technical reservations regarding the use of the SmartValve technology in the German power grid, indicating its potential to reduce the need for redispatch and enhance grid efficiency.

AusNet Services – Victoria, Australia: In Australia, AusNet Services deployed SmartValves on the Jindera–Wodonga 330 kV line to increase interregional export capability from New South Wales to Victoria by approximately 15 MW. This deployment helps balance power flows across multiple lines, relieving constraints that limit cross-border flows and reducing the risk of supply shortfalls in Victoria following the retirement of fossil fuel-based generation. The project showcases how the APFC technology can enhance grid flexibility and support the transition to renewable energy sources.

Central America – Regional Integration: A new project in Central America is utilizing the SmartValve technology to resolve grid congestion and strengthen the security of electricity supply across the region. The deployment aims to address overloads on several transmission circuits that limit power flows

nationally and across the interconnected power grids of the six countries in Central America (SIEPAC). By unlocking capacity on the existing grid, the project supports the integration of renewable energy projects and enhances regional energy security.

2.6 Challenges and Barriers

Despite the growing interest in APFC technologies and their demonstrated potential to improve transmission efficiency and flexibility, several technical, operational, regulatory, and economic challenges still hinder their widespread adoption. This section outlines key barriers and areas requiring further development to enable successful APFC integration on a scale.

2.6.1 Integration with Legacy Infrastructure

One of the foremost challenges in deploying APFC devices is integrating them with the existing utility infrastructure and operational frameworks. Many transmission systems rely on legacy protection and control systems that are not inherently compatible with digitally controlled power flow devices. APFC implementation may require substantial updates to substation layouts, relay settings, SCADA systems, and communication networks to support real-time data exchange and coordinated control.

Moreover, when multiple APFC devices are deployed across a wide-area network, overlapping zones of influence can complicate system operations. Coordinated control strategies, centralized or decentralized, must be carefully designed to account for the self and cross-sensitivities of each device, ensure stability, and prevent inadvertent interactions. These requirements significantly increase operational complexity, demanding enhanced situational awareness and operator training. Additionally, ensuring secure and reliable communication between field devices and control centers adds another layer of complexity, particularly in scenarios where high reliability and redundancy are required.

2.6.2 Cybersecurity and System Reliability

As APFC devices rely heavily on digital control and remote communication systems, cybersecurity emerges as a critical concern. Unauthorized access or manipulation of control signals could compromise grid stability, making APFC infrastructure a potential target for cyber threats. The deployment of APFCs must be accompanied by robust cybersecurity architectures that include encryption, authentication protocols, intrusion detection, and resilience to communication failures.

Reliability is another closely related issue. APFC devices are expected to function under both normal and emergency grid conditions. Their misoperation or failure to respond appropriately could lead to overloads, equipment stress, or violation of operating limits. To address this, APFC control schemes must be evaluated against key attributes: dependability, security, i.e., avoiding false trips, selectivity, robustness under varying system conditions, adaptability to evolving grid configurations, and performance in terms of response time.

2.6.3 Standards, Practices, and Planning Methodologies

The absence of established standards, specifications, and best practices is a major barrier to mainstream APFC adoption. While APFC has been successfully deployed in select projects, the technology is still emerging, with no long-standing track record across varied operating environments. The lack of standardized asset management practices, such as guidelines for inspection, maintenance, lifecycle planning, and end-of-life disposal, creates uncertainty and risk considering APFC investments.

In planning contexts, utilities need a methodical and consistent approach to evaluate APFC solutions. This includes robust cost-benefit analyses that consider optimal sizing, placement, and technology type for specific use cases. Comparative metrics are also needed to assess APFC devices alongside conventional alternatives like reconductoring or PSTs. Additionally, APFCs' ability to dynamically adjust power flows affects market dispatch and pricing, so transmission planning must account for day-ahead and real-time market interactions. The development of incentive mechanisms and operational models that support economic dispatch and reliability enhancement through APFCs remains an important area for future research and policy evolution.

2.6.4 Cost, Ownership, and Lifecycle Considerations

APFC deployments involve a high initial capital investment, which can be a constraint in capital-constrained environments. These costs include not only the cost of devices but also potential substation upgrades, real estate expansion, and integration engineering. In some cases, while APFCs can delay the need for larger capital projects, they may also introduce the risk of shifting congestion without fully alleviating it, especially if overall system headroom remains limited.

Beyond installation, utilities must be prepared to own, operate, and maintain these devices. This includes establishing the necessary organizational capabilities, tools, and workforce training to support ongoing operations and diagnostics. Any new deployment must be accompanied by clearly defined responsibilities for maintenance and emergency response. The long-term success of APFC projects depends not only on the technical merits of the devices but also on the institutional readiness of the utility to support their lifecycle management.

2.7 Modeling Procedure

APFCs can generally be modeled within simulation platforms using existing FACTS device models. Specifically, the SmartValve technology is supported by well-established modeling capabilities across a wide range of industry-standard planning and simulation tools. These models allow utilities and system planners to accurately simulate SmartValve behavior in both steady-state planning studies and dynamic analyses. Ready-to-use models are available for commonly used platforms, including PSS/E, PowerWorld, PowerFactory, PSLF, TSAT, ASPEN, MATLAB/Simulink, PSCAD/EMTDC, NEPLAN, INTEGRAL, Organon, and RSCAD/RTDS.

2.7.1 Steady State Model

In power flow studies, SmartValve technology can be modelled in the PSS/E using built-in FACTS device model. Suppose a SmartValve technology is identified to be installed on the line between Bus A and Bus B, as shown in Figure 8. To implement this, a new intermediate bus, such as Bus PFC-FACTS in Figure 8, needs to be added between Bus A and Bus B. Then, the existing line between Bus A and Bus B needs to be moved between Bus PFC-FACTS and Bus B. Next, a FACT device can be added between Bus A and Bus PFC-FACTS. Details on how to add a FACTS device in different versions of PSS/E are discussed as follows.

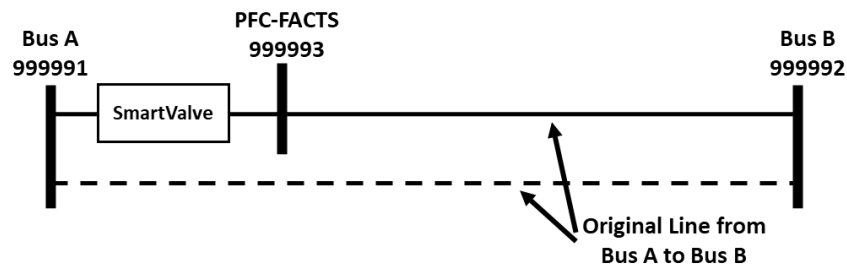


Figure 9. Selected SmartValve Deployment Location Between Bus A and Bus B.

In PSSE v33, FACTS device between Bus A and PFC-FACTS can be added by selecting both Buses and then selecting FACTS device from the toolbar menu. Then, once PSS/E prompts to select a FACTS device type, choose “Create only series element”.

In PSSE, for connecting the FACTS between the two buses, the FACTS data must be entered via “Network Data” table, under Branch, category FACTS. Once the “Network Data” is updated, the diagram should be updated by using the “Auto-Draw” option, otherwise the element will appear to be connected to earth.

In order to represent the SmartValve as a SSSC using the FACTS Device model, set the parameters as indicated in Figure 10, specifically, Shunt Max (MVA), Bridge Max (MW), V Series Reference, and Dummy Series X (pu). Further modeling details can be found in Smart Wires modeling procedure²⁶.

²⁶ “Modelling SmartValve as a PSSE FACTS device,” *Smart Wire*, 2024.

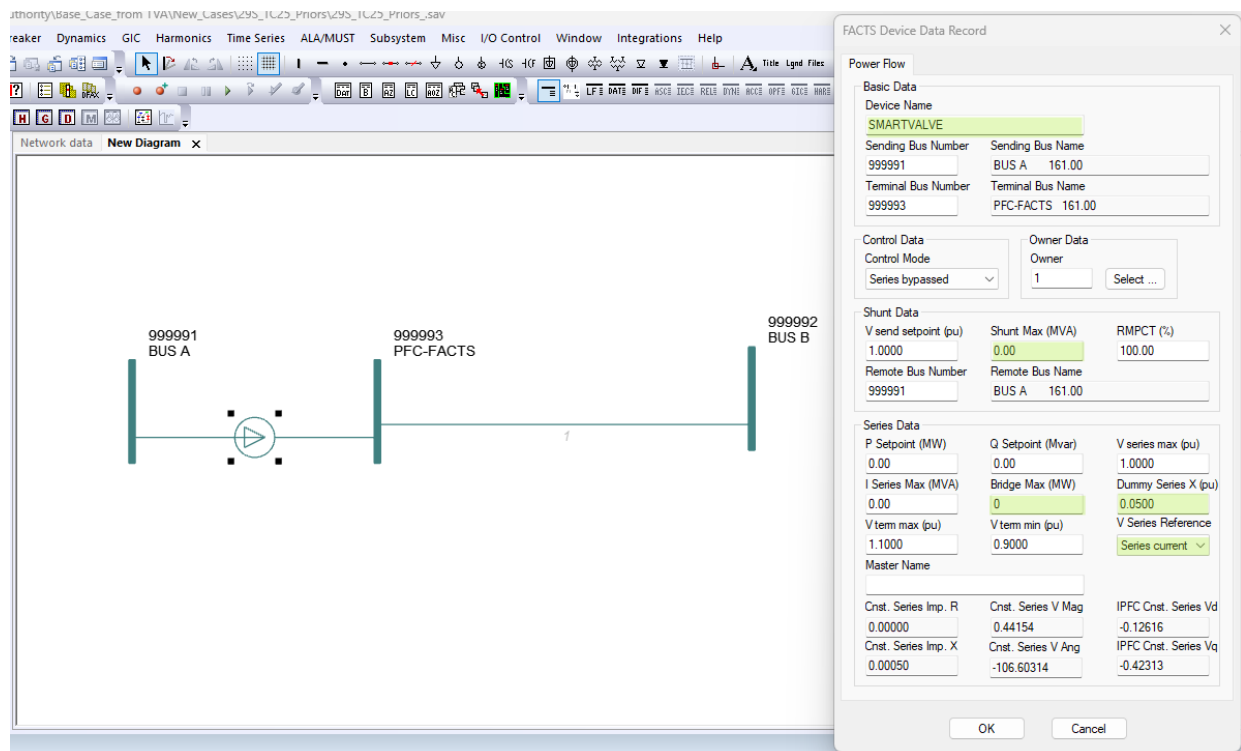


Figure 10: FACTS Device Data Record with Parameters Representing a SmartValve.

2.7.2 Dynamic Model

In dynamic stability studies, the SmartValve is modeled using a combination of CRANIT and SVALVE in PSS/E, representing the injected voltage as a controllable series reactance via two series reactors, where:

- Two variable series reactor models (CRANIT), which are part of the standard model library; and,
- A branch device model (SVALVE) that manages the set point of the CRANIT models.

Figure 11, shows the branch tab in PSS/E representing SmartValve model. Further modeling details can be found in Smart Wires modeling procedure²⁷.

Network data		Test_V33.sld		Dynamics data		x			
	From Bus Number	From Bus Name		To Bus Number	To Bus Name	Id	Model	In Service	Type
	1	BUS1	220.00	2002	SV2 220.00	99	CRANIT	☒	Std
	2001	SV1	220.00	2002	SV2 220.00	98	CRANIT	☒	Std
▶	2001	SV1	220.00	3	BUS3 220.00	1	SVALVE	☒	Wrtn
*								☐	

Figure 11: Branch Device Tab Showing SmartValve Model.

²⁷ "SmartValve dynamic model user manual for PSSE," *Smart Wires*, 2022.

2.7.3 Short Circuit Model

In short circuit studies, Smart Wires developed a SmartValve protection model, that enables the study of the SmartValve and Bypass deployment impact on protection schemes. The model represents SmartValve and Bypass devices using an equivalent impedance and bypass switch. The model includes the following SmartValve protection features:

- **Overcurrent Protection:** If line current exceeds the defined threshold, the Bypass will short-circuit the protected SmartValve devices in less than 1 milliseconds.
- **DC Link Overvoltage Protection:** If the SmartValve device's internal DC link capacitor voltage exceeds the defined threshold, the Bypass will short-circuit the protected SmartValve devices within $\frac{1}{4}$ cycle.

Further modeling details can be found in Smart Wires modeling procedure²⁸.

²⁸ "SmartValve protection model user manual for ASPEN OneLiner," *Smart Wires*, 2025.

3. Transmission Switching

3.1 Introduction

ATTs can play a critical role in grid modernization by improving system performance and expanding bulk power system capacity without relying solely on conventional upgrades. These technologies enable transmission owners and operators to rapidly and cost-effectively increase transmission capacity while maintaining grid reliability, safety, and efficiency.

This report focuses on transmission switching, as one of the alternative transmission technologies with the potential to enhance grid capacity and reliability. Transmission switching refers to the process of redirecting power flows from one transmission path to another through topology reconfiguration. This involves opening or closing switching devices, such as circuit breakers or other controllable equipment, to reroute power flows around congested or overloaded areas. By solving a topology optimization problem, transmission switching identifies new configurations that reduce or eliminate overloads while maintaining system reliability. This approach can improve the overall transfer capacity of the grid, as shown in a representative example in Figure 12.

This chapter explores the varied applications and benefits of transmission switching as an alternative transmission technology to mitigate system violations. The following sections provide an in-depth examination of the fundamental technology of transmission switching, the various drivers of transmission switching deployment, and some best practices for their utilization.

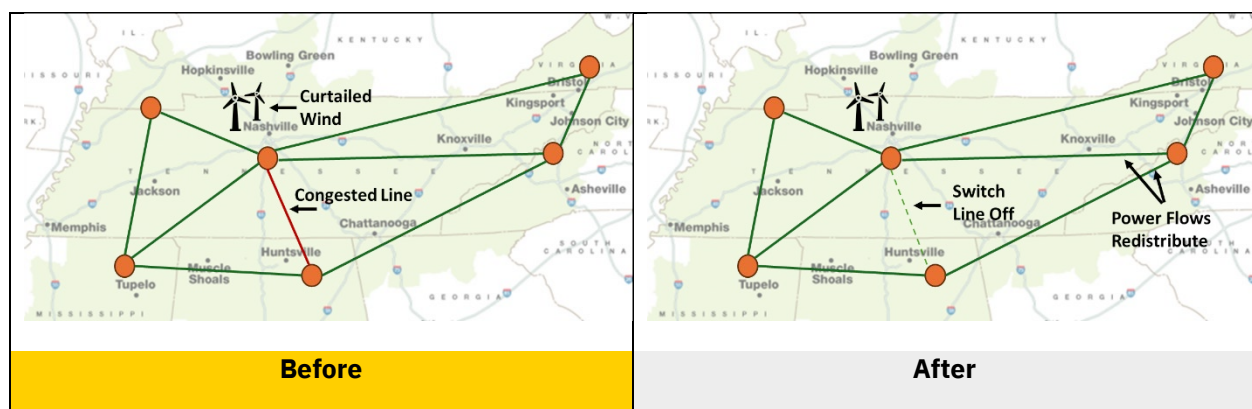


Figure 12: A Representative Example of Transmission Switching to Relieve a Congested Line.

3.2 Technology Background

Transmission switching is a grid-enhancing technology that allows operators to reconfigure the network topology by opening or closing switching devices, such as circuit breakers. These actions are determined through optimization techniques and can significantly improve the utilization of existing grid infrastructure. This section provides an overview of the operational principles of transmission switching and discusses the computational complexity involved in identifying optimal switching actions.

3.2.1 Operational Principles of Transmission Switching

Transmission switching involves changing the status of switching devices to reroute power flows around congested or overloaded transmission elements, such as lines or transformers, thereby creating a new, optimized grid topology. These reconfigurations are typically implemented by manipulating circuit breakers at substations. Figure 13 illustrates a substation equipped with circuit breakers, which can be used to modify the system topology in real-time.



Figure 13: Substation Circuit Breakers are Used to Change System Topology.

This approach offers a flexible and cost-effective method to increase transfer capacity and enhance operational reliability, particularly during periods of high system stress. Transmission switching is especially valuable in the current energy landscape, where the rapid growth of large load interconnections, such as data centers, is outpacing the development of new transmission infrastructure. The long lead times associated with building new lines contrast sharply with the fast deployment of these high-demand loads, leading to increased system congestion and a higher likelihood of overloading conditions.

In such cases, transmission switching can serve as a bridge solution, offering immediate relief while long-term infrastructure investments are planned and implemented. By redirecting power flows and relieving congested elements, switching actions help maintain the system within safe operating limits, ensuring both stability and reliability.

3.2.2 Computational Challenges and Optimization Approaches

While transmission switching offers considerable operational benefits, identifying the optimal set of switching actions is a complex problem due to the vast number of potential network configurations. The challenge lies in the combinatorial nature of the problem: each switching device can be either open or closed, leading to an exponential number of possible configurations. To illustrate this, consider the double-breaker-double-bus substation configuration shown in Figure 14. Each square represents a circuit breaker, and each blue circle represents a substation node. The electrical identity of each node depends on the status of the associated breakers.

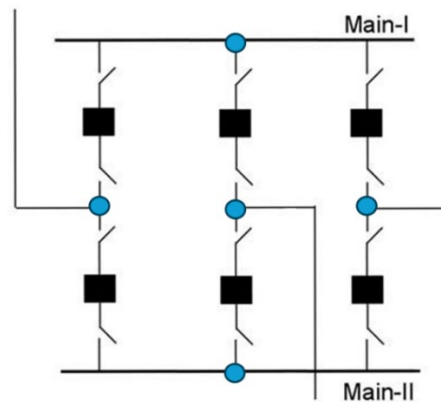


Figure 14: Double-Breaker-Double-Bus Substation Configuration²⁹.

If all circuit breakers are open, then each of the substation nodes (blue circles) represent an electrically distinct node, and so the substation appears as five nodes in the network. If all circuit breakers are closed, all substation nodes are electrically identical, and the substation appears as a single node in the network. Depending on the status of each circuit breaker, the total number of possible switching configurations for this substation is $64 = 2^6$. In general, the number of possible switching configurations for a grid with n switching devices, e.g., circuit breakers or other controllable devices, is 2^n .

Given that real-world power systems networks consist of many such substations, each typically equipped with multiple circuit breakers, and each breaker potentially impacting the power flow in a unique different way, the number of possible switching actions in a real-life network can be exponentially large. This large range of options makes it increasingly challenging to evaluate every potential switching configuration to

²⁹ "Transmission topology optimization: state-of-the-art white paper," *Electric Power Research Institute (EPRI)*, January 2025.

identify the most effective solution for reducing or eliminating overload conditions while maintaining overall grid reliability.

Traditionally, switching actions were identified manually based on the knowledge of the system of expert staff, which may not always and necessarily reach the best switching solution. However, recent advances in optimization algorithms have speeded up the development of advanced software solutions to determine the best switching actions. This has led to the growth of the transmission topology optimization software, which is specifically designed to efficiently analyze all possible switching actions and identify safe switching solutions that improve grid operations. The transmission topology optimization can be standalone or integrated with energy management systems and market management systems. The actions taken within the transmission topology optimization are referred to as topology reconfigurations.

3.3 Applications and Benefits

Transmission switching and topology optimization are powerful strategies that enhance grid reliability, flexibility, and efficiency. These techniques offer multiple operational and planning benefits, particularly in addressing thermal overloads, voltage violations, and system stability concerns. This section explores how transmission switching actions can be effectively applied to mitigate each of these types of violations.

3.3.1 Thermal Violations

Transmission switching is an effective method to alleviate congestion and mitigate thermal overload on transmission lines. The underlying principle involves rerouting power flows from overloaded elements to less congested paths through controlled topology changes. The following two scenarios illustrate practical applications of transmission switching for thermal violation mitigation.

The first scenario occurs mostly in parallel corridors at the same or different voltage levels. Figure 15 illustrates a case with two corridors at different voltage levels. One path consists of a single 500 MW-rated transmission line. The other path includes several interconnected lines, one of which is limited to 50 MW, as marked on the figure.

Under certain conditions, such as excess generation at one end of the path or a system contingency, the line with 50 MW rating would be overloaded, as shown in left figure. A simple switching practice in this example is to turn the overloaded line out of service by opening the circuit breakers at the two ends of the line and shifting the power flow to the parallel line with more available capacity, as shown in the right figure. This is a sample transmission switching action that helps to address a thermal violation by turning the overloaded line out of service.

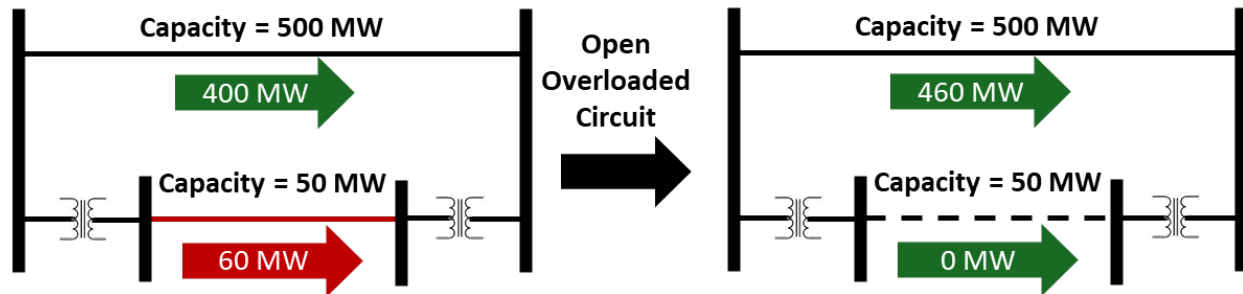


Figure 15: Thermal Violation Mitigation Using Transmission Switching Actions²⁹.
Before the switching action (left) and after the switching action (right).

In the second scenario, consider a transmission line overloaded because of contingency. In such cases, transmission switching aims to mitigate the thermal overload by system reconfiguration, such that compared to the first scenario, the overloaded facility remains online, i.e., the overloaded line will not be switched off. Like the first scenario, this switching process will be feasible if and only if the candidate line which will be switched off is non-radial. This constraint ensures that the action will not isolate any portion of the load.

The two examples above highlight the importance of identifying the best switching actions that address thermal violations without creating new ones. Therefore, the switching solution should address some of the thermal violations and reduce the overall stress level for the network. PJM, for instance, maintains a library of predefined switching procedures designed to relieve transmission constraints under various conditions³⁰.

3.3.2 Voltage Violations

Transmission switching can also help address voltage violations in transmission systems, especially when transmission lines are lightly loaded. When a transmission line is lightly loaded, less power flows through the line, often due to its high impedance. This can lead to a significant voltage difference between the two ends of the line, which can eventually cause voltages to exceed acceptable limits or lead to significant deviations between pre-contingency and post-contingency voltages. Such voltage issues are more common in long transmission lines or during off-peak demand periods when system loads are low, such as in the winter and spring seasons. This is because the capacitive component of a transmission line is the predominant component during off-peak demand periods whereas the reactive component is predominant at peak demand periods. Consequently, during off-peak demand periods, there can be situations where a transmission line causes voltage violations in the network, i.e., the voltage levels are too high.

To address these issues, one effective approach is to select key transmission lines that are not currently needed for reliability considerations and take these lines out of service to alleviate voltage violations. This action can improve the voltage profiles at nearby substations and reduce the risk of voltage instability.

³⁰ "Switching solutions," PJM. [Online]. Available: [Link](#).

Further, such switching actions can enhance the transfer capability of nearby higher-voltage transmission lines by redistributing power flow more effectively across the network. In long-term planning and real-time operations, the ability to manage voltage through switching actions provides system operators with a flexible and cost-effective tool that reduces the need for additional reactive power compensation equipment or costly transmission upgrades. Therefore, using transmission switching can improve voltage profiles, reduce voltage instability, and enhance overall grid performance, especially during off-peak demand periods. This technique has been implemented by PJM³¹ and Exelon³².

3.3.3 Stability Violations

Transmission switching plays an essential role in addressing stability violations in power systems. Here are some ways transmission switching can enhance grid stability and help it recover from disturbances, such as faults, to maintain steady operation.

When a fault occurs in the power system, specific switching actions, such as opening or closing breakers, can redirect power flow away from overloaded or vulnerable areas. This helps reduce stress on crucial components and prevents cascading failures.

Another significant advantage of transmission switching is its ability to improve the damping of post-contingency system oscillations. After a disturbance occurs, oscillations can destabilize the grid if not properly controlled. By adjusting power flow paths and system impedance, transmission switching increases the damping ratio, enabling the system to stabilize more quickly and avoid delayed instability. Therefore, optimizing transmission switching to maximize post-contingency damping is key to enhancing grid resilience and stability. This becomes even more critical as power systems integrate more renewable energy sources and face increasingly complex operational conditions.

3.3.4 Summary of Grid Challenges Addressed by Transmission Switching

Table 12 summarizes the degree of impact transmission switching has on addressing various grid reliability challenges.

Table 12: Degree of Impact of Transmission Switching on Grid Reliability Challenges

Thermal Violations	Voltage Violations	Stability Violations
Notable	Notable	Notable

³¹ A. Ott, “private communication,” *PJM*, July 2008.

³² S. Nauman, “private communication,” *Exelon*, July 2008.

3.4 Technical and Operational Considerations

The implementation of transmission switching might affect key areas within a utility, including generation interconnection, transmission planning, system protection, operations, and engineering design. A comprehensive understanding of the role and impact of transmission switching across utility departments is essential for effective deployment, operational reliability, and long-term system planning. This section outlines the specific considerations each department must account for when integrating transmission switching solution into the power grid.

3.4.1 Generation Interconnection

As discussed earlier, the objective of FERC Order No. 2023 is to improve the generation interconnection process through the implementation of ATTs, including transmission switching. A significant portion of new generation being added to the grid consists of renewable energy resources, primarily wind and solar, which are often sited in remote areas, far from major load centers. As a result, there may be scenarios in which generation output causes localized transmission line overloads, which can be mitigated with transmission switching, similar to the examples discussed in before.

Once an overloaded transmission line is identified in a SIS, as a part of evaluating single interconnection request or a cluster interconnection request, the effectiveness of transmission switching should be evaluated. In cluster studies, the transmission switching assessment should be performed in “Study case with priors”, where requested interconnection facilities in the cluster are dispatched at maximum output unless PTDF is less than a pre-determined values, e.g., 5% in TRANS-SPP-07.010.

Note that, the feasibility and safety of transmission switching must be evaluated at identified facilities, as switching actions are typically prohibited near nuclear power plants and other critical infrastructure due to their potential adverse impact on system stability and the consequent risks to the safety of those facilities.

Here are some insights that may be useful during the transmission switching development in a generation interconnection process under NERC Categories P0-P7 contingencies:

- For violations that appeared in the normal system condition (i.e., NERC category P0), transmission switching is generally not an optimal solution for resolving overload violations, as it may introduce additional overload violations when the system is stressed under contingency conditions.
- For violation caused by NERC categories P1-P4 and P7, transmission switching may be a feasible solution if all the following conditions are met:
 - Each overloaded facility does not operate in a radial configuration under post - contingency conditions.
 - Only one facility is overloaded, or if multiple facilities are affected, then they all belong to the same transmission corridor.
 - At least one alternative path exists with enough capacity to accommodate the additional power transfer.

-
- The feasible switching action does not introduce new violations.
 - At extra high voltage levels (i.e., 300 kV and above), transmission switching may be impractical due to limited available capacity in parallel corridors.
 - For violations caused by NERC category P5 contingencies, transmission switching may not be a cost-effective solution, as addressing redundancy through protection system enhancements is typically the most straightforward approach.
 - For violations caused by NERC category P6 contingencies, the allowable load drop or generation dispatch limit is typically high. If the threshold exceeds this limit, the amount of power that must be redirected to other corridors can be significant, making transmission switching an impractical solution.
 - Transmission switching may be a feasible solution for mild to moderate overload conditions on transmission lines with lower ratings.

In addition, transmission switching can serve either as a long-term remedy or as a transitional solution to manage reliability and deliverability until planned transmission upgrades are completed.

Similar scenarios may arise in cases involving voltage or stability violations. In such instances, transmission switching may also serve as an effective mitigation strategy, either as a temporary operational tool or as a complement to longer-term infrastructure solutions.

3.4.2 Transmission Planning

FERC Order No. 1920 aims to enhance regional transmission planning by requiring transmission providers to evaluate the use of ATTs, such as transmission switching, as part of their long-term planning strategies. This requirement is especially important given the continued slow pace of new high-voltage transmission construction. According to a recent report, only 55 miles of transmission lines operating at 345 kV and above were built in the United States in 2023³³. This limited expansion is increasingly concerning considering the rapid growth of large load centers, such as data centers, and the continued integration of renewable energy resources, both of which demand a more flexible and resilient transmission grid capable of efficiently delivering power across long distances.

Unlike traditional capital-intensive projects, transmission switching can be deployed within days or weeks, offering a rapid, low-cost method for alleviating grid constraints. It can serve as either a temporary operational solution or a complementary measure alongside longer-term infrastructure investments, enabling planners to respond more quickly to evolving system needs.

Transmission switching development process insights mentioned in Section 3.4.1 (items a-f) also applies to transmission expansion planning.

³³ N. Shreve, Z. Zimmerman, R. Gramlich, “Fewer new miles: the US transmission grid in the 2020s,” *Americans for a Clean Energy Grid*, July 2024.

Furthermore, transmission switching can act as an intermittent, short-term solution in temporary violation scenarios, such as during planned outages or when critical equipment is unavailable due to long lead times for replacement or repair. In such cases, transmission switching provides a practical way to maintain system reliability while avoiding unnecessary curtailment or delays in service.

3.4.3 System Protection

In addition to supporting generation interconnection and transmission expansion planning, switching technologies also play a critical role in system protection through the implementation of Special Protection Schemes (SPS). An SPS is designed to detect abnormal system conditions, e.g., abnormal system configuration, in network configuration and automatically execute corrective actions to maintain system reliability³⁴. The SPS can involve a coordinated sequence of actions, including changing the status of switching devices and circuit breakers, tripping local transmission facilities, or adjusting generator and load operations. The goal of such actions is to maintain acceptable transmission lines loading, system voltages, and transient stabilities during outage conditions. The application of SPS is typically limited to temporary and severe conditions, e.g., high-voltage transmission lines operating at 345 kV and above. Therefore, due to their complexity and potential system-wide impacts, SPS must be used with caution. Clear operational procedures should be in place to ensure that these schemes are disabled once the triggering conditions drop and normal or less critical operating conditions are restored.

3.4.4 Operations and Control Systems

Further, transmission switching deployment by grid operators will assist operations, reduce thermal overloading, and minimize renewable curtailment. This technology is particularly effective in the operational timeframe. Topology optimization tools can be deployed to help the operator in making decisions during outage situations based on previously studied or real-time studies. Such tools can then be integrated into the full operations environment to allow for automated switching solutions during system events. Integrating topology optimizations into grid operations offers significant improvements and can alleviate thermal overloading.

3.4.5 Engineering and Design

From an engineering and design perspective, the impact of implementing transmission switching is generally limited compared to other areas. In most cases, transmission switching leverages existing infrastructure and does not require substantial physical system modifications. However, if switching operations are implemented on transmission lines not originally designed for reconfiguration, targeted upgrades may be necessary. These upgrades include the installation of new circuit breakers, remotely-controlled switches, or enhancements to substation control and communication systems.

³⁴ “PJM manual 07: PJM protection standards,” *PJM*, May 2019.

3.4.6 Summary of Utility-Wide Impacts

Table 13 summarizes the impact of transmission switching across various utility departments.

Table 13: Utility-Wide Impacts of Transmission Switching Deployment.

Utility Function	Impact Level	Primary Benefits of Transmission Switching
Generation Interconnection	High	Provides mitigation for overloads in interconnection studies; supports renewable integration.
Transmission Planning	High	Offers low-cost, rapid solutions for congestion relief; enhances flexibility in long-term system development.
System Protection	Medium	Enables implementation of Special Protection Schemes (SPS); supports stability during contingency conditions.
Operations and Control	High	Improves real-time system flexibility; enables congestion management and curtailment reduction.
Engineering and Design	Low	Minor impacts unless new circuit breakers or control systems are required; generally, uses existing infrastructure.

3.5 Best Practice

Several real-world case studies demonstrate the successful application of transmission switching for enhancing grid reliability and efficiency. This section presents notable examples of implemented transmission switching actions. Additional examples of operational transmission switching and topology optimization can be found in these two references^{35, 36}.

3.5.1 PJM Switching Solutions

PJM has identified and implemented various transmission switching solutions aimed at alleviating system overloads and voltage issues across its service territory³⁰. These projects focus on mitigating thermal violations on transmission lines and transformers through strategic actions such as opening specific circuit breakers, reconfiguring bus ties, and adjusting transformer operations.

For instance, to relieve thermal overloads on the Plymouth Meeting–Bryn Mawr 138 kV line, PJM operator opens specific circuit breakers to reroute power flow, reducing the overload by approximately 15% (30 MVA). In cases of contingency overloads, PJM outlines multi-step switching procedures to redistribute power flows, often in coordination with local and regional control centers to prevent the emergence of new reliability concerns.

³⁵ “Assessment and evaluation of grid enhancing technologies (GETs),” *Electric Power Engineers (EPE)*, February 2025. [Online]. Available: [Link](#).

³⁶ “Topology optimization case studies,” *NewGrid*, May 2024. [Online]. Available: [Link](#).

In addition to thermal and contingency management, some projects also focus on voltage control and fault duty concerns. For example, in the case of high voltage at the Ox-Glebe 230kV substation, PJM considers opening specific lines to balance voltage levels across the grid. Similarly, load transfer strategies like closing or opening transformer circuit breakers are studied to manage voltage fluctuations and system reliability.

3.5.2 Southwest Power Pool (SPP) Switching Solutions

In 2018, SPP evaluated the potential of using topology optimization to develop Corrective Action Plans (CAP) that relied on reconfigurations and avoided load shedding for NERC categories P6, P7 and Extreme Event violations. SPP Planning selected three events for evaluation, one of each NERC category listed, that had CAPs consisting of load shedding (up to 243 MW of load shed). The reconfiguration solutions identified and validated by SPP provided full relief under NERC TPL-001 in SPP and eliminated the need of load shed actions in those CAPs.

Additionally, the benefits of topology optimization are studied in SPP by looking at 20 real-time snapshots of the entire SPP system, representing a wide range of grid conditions ³⁷. This study shows that single action switching solutions on facilities below 345 kV led to 26% flow relief. For instance, SPP applied a topology optimization to identify the best transmission switching solutions to a small portion of their region in the Midwest to reduce wind generation curtailment. As another example, two constraints in SPP cost \$25 million per year and affected market outcomes in 16% of the hours and reconfigurations were able to resolve these constraints³⁸.

3.5.3 National Grid ESO Switching Solutions

National Grid ESO, the Great Britain transmission system operator, investigated the feasibility and value of adopting existing topology optimization algorithms for their service territory. Using historical data, the study found that topology optimization could increase transfer capacity across large, heavily binding transmission constraints, such as into the London metropolitan area, by 3% to 12% even under outage conditions.

3.6 Challenges and Barriers

While transmission switching and topology optimization offer significant operational and economic benefits, several challenges and barriers hinder their widespread adoption. These challenges span technical, operational, institutional, and cultural dimensions, as outlined below.

³⁷ “Transmission topology optimization congestion relief in operations and operations planning,” *SPP*, 2018. [Online]. Available: [Link](#)

³⁸ “State of the market 2019,” *Southwest Power Pool Market Monitoring Unit*, May 2020. [Online]. Available: [Link](#).

3.6.1 Lack of Established Reconfiguration Protocols

A major barrier is the absence of well-defined, standardized procedures for implementing network reconfigurations during both planning and real-time operations. Without formalized workflows and clearly delineated responsibilities, transmission switching can raise concerns about system reliability, coordination among operators, and safe execution during contingencies.

3.6.2 Computational Complexity and Tool Limitations

Topology optimization is computationally intensive, especially when incorporated into production cost modeling or operational planning for large-scale systems. Many existing production simulation tools are not yet equipped to treat switching decisions as endogenous variables due to the discrete, non-linear nature of the problem. As a result, topology changes are often evaluated outside the simulation environment and manually inputted as fixed configurations, which limit flexibility and integration.

3.6.3 Equipment Wear and Breaker Lifecycle Concerns

Frequent switching of circuit breakers due to optimized network configurations can increase mechanical wear, leading to more frequent maintenance or accelerated equipment replacement cycles. This raises both cost and reliability concerns, particularly if the same subset of devices is repeatedly identified as optimal for switching. However, research and field studies suggest that the added switching duty is often comparable to or less than the frequency of existing planned outages in many regions.

3.6.4 Cybersecurity and Protection Coordination

Switching network topology dynamically can affect protection coordination and relay settings. If not properly accounted for, this could increase the risk of mis-operation or protection failure during faults. As switching solutions increasingly relies on automation and centralized decision-making, they may become more vulnerable to cyber threats. Ensuring secure communication and control protocols is critical to avoid malicious manipulation of grid topology.

3.6.5 Misaligned Incentives and Value Capture

Topology optimization typically involves low capital costs and high system-level benefits, e.g., congestion relief, reduced curtailment, improved reliability. However, these benefits often accrue to system operators and market participants rather than the transmission owners who must implement the switching. This disconnects in value capture discourages investment and innovation, especially in vertically disaggregated or regulated environments.

3.7 Modeling Procedure

This section outlines the modeling methodologies for integrating switching devices into power flow models and contingency definitions.

3.7.1 Steady State Model

Switching devices, such as circuit breakers or disconnect switches, are typically represented as near-zero impedance elements in power flow models. Depending on the modeling convention used, these devices can be implemented in one of the following ways:

- **Node-Breaker Configuration:** In this configuration, switching devices are explicitly represented as discrete components, e.g., breakers or switches, between equipment and buses. This allows for detailed modeling of the physical network topology and breaker-level operations. As shown on the left side of Figure 16, a switching device is modeled as a controllable breaker, enabling the simulation of various switching scenarios, including opening or closing paths between nodes.
- **Bus-Branch Configuration:** In simpler models where system topology is abstracted at the bus level, switching devices are typically represented as near-zero impedance branches. These branches behave like standard transmission lines but with extremely low impedance values, often with a reactance of 0.001 pu on the system base, and resistance and charging parameters set to zero, as shown on the right side of Figure 16.

The figure consists of two side-by-side software dialog boxes. The left dialog, titled 'Switching Device Data Record', has a 'Power Flow' tab. It contains fields for 'Station' (1), 'ID' (1), 'From Node Number' (2), 'From Node Name' (SUB\$138\$02), 'To Node' (5), and 'To Node' (SUB\$138\$01). It also has checkboxes for 'Closed' and 'Closed (Normal)'. A 'Device Name' field contains 'CIRCUIT BREAKER 2-5' and a 'Switching Device' dropdown menu is set to 'Circuit breaker'. The 'Switching Device Data' section shows 'Reactance' (0.0) and 'Rate A (MVA)' (0.0). The right dialog, titled 'Branch Data Record', has 'Power Flow' and 'Short Circuit' tabs. The 'Basic Data' section shows 'From Bus Number' (1), 'From Bus Name' (BUS A), 'To Bus Number' (2), 'To Bus Name' (BUS B), and 'Branch ID' (Z1). The 'Branch Data' section shows 'Line R (pu)' (0.000000), 'Line X (pu)' (0.000010), 'Line G From (pu)' (0.000000), 'Line G To (pu)' (0.000000), 'Line B From (pu)' (0.000000), and 'Line B To (pu)' (0.000000). The 'Ratings (I as MVA)' section shows 'RATE1' (1334.0), 'RATE2' (1725.0), 'RATE3' (2084.0), 'RATE4' (1837.0), and 'RATE5' (n.a.). The 'Owner Data' section shows 'Owner' (9999) and 'Fraction' (1.000).

Figure 16: Modeling Approaches to Implement Switching Devices in Power Flow Models.
The Node-Breaker Configuration (left) and the Bus-Branch Configuration (right).

3.7.2 Contingency Definition

Switching actions should also be added into contingency definitions to help mitigate overload conditions on specific transmission lines during an outage. This can be obtained through a control scheme that coordinates power flows across selected transmission lines and sends control commands for transmission switching. Such a scheme is commonly referred to as a remedial action scheme (RAS). A RAS is a scheme designed to detect predetermined system conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation, tripping load, or reconfiguring topology.

3.7.3 Short Circuit Model

Practically transmission switching involves switching actions on normally closed circuit breakers rather than normally open ones, which results in a new grid configuration. This configuration should be applied and revisited in short circuit study to ensure system reliability.

4. Tower Lifting

4.1 Introduction

The evolving demands on the electric grid, driven by increasing load, integration of renewable energy sources, and the aging condition of existing infrastructure, have intensified the need for solutions to optimize the existing transmission network. Traditional methods of expanding capacity through new line construction are frequently impeded by challenges such as limited ROW, lengthy permitting processes and high capital costs. These barriers, coupled with the critical need to maintain system reliability and safety, highlight the importance of alternative technologies that can enhance the grid with reduced disruption and cost.

Tower Lifting is a viable ATT that can address some of these challenges. By increasing the height of existing transmission structures, tower lifting allows utilities to improve line clearances, accommodate advanced conductors with higher ampacity, and extend the operational capacity of transmission corridors without constructing entirely new lines. The method leverages a range of lifting technologies, from traditional crane-based approaches to more advanced systems such as AMPJACK, and the enclosing method.

This chapter outlines the technical basis and practical applications of tower lifting within the broader objective of modernizing transmission systems. It begins with a technology background and overview of lifting methods, followed by a discussion of key application areas including clearance mitigation, ROW constraints, and renewable integration. Subsequent sections address technical and operational considerations such as structural analysis, safety protocols, utility-wide impacts, and system re-rating procedures. Best practices from industry deployments are reviewed, along with challenges and barriers to implementation. The report concludes with modeling approaches essential for accurately representing lifted towers in power system studies, such as steady state, short circuit, and dynamic studies.

4.2 Technology Background

4.2.1 Background and Motivation

The electric power grid is undergoing a period of rapid transformation driven by rising energy demand and the accelerated integration of renewable energy resources. These developments place unprecedented stress on the existing transmission infrastructure, which is not only near its capacity limits but is also largely aging and in need of significant upgrades. To accommodate the additional power flow and ensure grid reliability, substantial investment is required in both new transmission projects and the reinforcement of existing lines.

However, the execution of these infrastructure projects is frequently hindered by a range of challenges. ROW acquisition and land compensation remain major obstacles, often compounded by public opposition

from local communities and environmental advocacy groups. These social and environmental concerns can lead to project delays, increased costs, and even cancellations.

Moreover, maintenance and reinforcement work, especially on low-height towers, are sometimes deferred due to access limitations or logistical constraints. Such delays can result in serious safety incidents and unexpected power outages, further emphasizing the need for innovative solutions.

One key solution is tower lifting, a technique that involves raising the height of existing transmission towers. This approach is increasingly being explored as a practical alternative to building entirely new infrastructure, particularly in densely populated or environmentally sensitive areas. Tower lifting can facilitate the use of advanced high-capacity conductors or support reconductoring efforts, thereby enhancing the capacity of existing lines without the need for additional ROW or extensive civil works.

In this context, tower lifting emerges not only as a cost-effective and environmentally considerate strategy but also as a critical enabler in modernizing the grid to meet evolving energy needs.

4.2.2 Tower Lifting Overview

Tower lifting refers to the process of elevating existing transmission towers using specialized equipment and engineering techniques, primarily for maintenance, upgrades, or capacity enhancement. The objective is to raise the towers to a predetermined height while ensuring structural integrity, proper alignment, and safe operation of the electrical conductors. This method enables utilities to meet evolving transmission requirements with minimal disruption to existing infrastructure and surrounding environments.

In stakeholder feedback received during this project, Duke Energy noted that tower lifting should not be limited to raising existing lattice towers, but should also include replacing wooden structures with taller steel structures where doing so increases conductor clearance and facility ratings.

The adoption of tower lifting is typically driven by a range of technical and logistical considerations, including:

- ROW and environmental challenges
- Safety improvements, particularly related to ground clearance
- Minimization of downtime for maintenance on critical transmission lines
- Residual structural capacity of existing towers, foundations, and mechanical components
- Restricted site access, which limits the feasibility of conventional construction

By enabling height adjustments without completely rebuilding infrastructure, tower lifting presents a practical and strategic alternative to new transmission construction, especially in challenging environments.

4.2.2.1 Tower Lifting for Increasing Transmission Capacity

Tower lifting is emerging as a strategic method for enhancing the capacity of existing transmission lines without the need for constructing new towers. By elevating existing tower structures, utilities can accommodate the installation of higher-capacity conductors, thereby enabling greater power transfer through existing corridors.

A key limitation in power transmission is conductor sag, which increases with temperature and reduces ground clearance. This thermal sag limits the maximum allowable current through a line, especially during peak load or high-temperature conditions. Tower lifting directly addresses this challenge by increasing ground clearance, allowing conductors to operate safely at higher temperatures without violating safety regulations.

When tower lifting is combined with advanced low-sag conductors, such as HTLS conductors, the benefits are further amplified. These modern conductors are specifically designed to carry higher currents with reduced thermal expansion, and their performance is optimized when greater clearance is available. Lifting the towers enables full utilization of these advanced technologies, resulting in significantly improved ampacity and system reliability.

This technique is particularly valuable in scenarios where the construction of new transmission lines is restricted due to permitting delays, ROW limitations, and community or environmental opposition.

By leveraging existing infrastructure and maximizing its performance, tower lifting presents a cost-effective, minimally invasive, and environmentally considerate solution to meet growing electricity demand and integrate additional renewable energy resources. It aligns with the broader industry trend toward optimizing and modernizing existing grid assets as part of a sustainable energy future.

4.2.2.2 Tower Lifting Technologies

Several technologies and methods have been developed and implemented globally to facilitate tower lifting. Each approach offers distinct advantages and limitations depending on site conditions, voltage levels, and project objectives.

- **Traditional Lifting Method³⁹:** This conventional technique typically involves the use of cranes and in some cases helicopters, lifting sections of transmission towers. While widely understood and accessible, this method presents several challenges:
 - Requires heavy equipment with significant logistical demands
 - High carbon footprint due to crane and helicopter usage
 - Often necessitates complete or partial disassembly of the conductors
 - Typically involves substantial outages and extended downtime

³⁹ A. Dupree, F. Liu, J. Rumble, R. Ortegón, “Raising transmission line steel towers,” *Electrical Transmission and Substation Structures*, 2015.

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- **Enclosing Method⁴⁰:** This method was developed to minimize downtime during tower replacement or upgrades. It involves enclosing the existing structure with a modified framework, including a stub extension inserted at the midsection (waist) of the tower to increase height without replacing the full lattice structure. Key steps include:

- Reinforcement of the existing foundation
- Installation of anchorage for the stub extension
- Building a new tower adjacent to the existing one
- Circuit wiring and commissioning
- Dismantling of the original tower

This technique has been successfully implemented for 345 kV and 145 kV transmission circuits and is especially effective in reducing project duration and maintaining line operation during construction.

- **Enprom Lift System-based Method⁴¹:** Enprom's lifting system is a cutting-edge, mechanized approach designed to elevate towers without the need to disassemble the conductors or, in some cases, without requiring an outage. Features include:

- Four independent, self-propelled lifting units, each attached to a tower leg
- Internal mini-cranes within each lift module
- Computer-controlled synchronization to ensure balanced and stable lifting
- Capability to lift towers up to 400 kV (double-circuit) and under specific conditions, up to 750 kV
- Maximum height increase: 5 meters

This method offers a fast, precise, and low-disruption solution, particularly useful in urban or constrained areas.

- **AMPJACK Lift System-based Method:** The AMPJACK system is a self-contained, hydraulically operated tower lifting solution designed for on-site height extension without requiring conductor removal or outages, see Figure 17. Notable features include:

- Compact, transportable system, described as a “crane in a box”
- Hydraulic jacking of tower legs, enabling installation of new structural components during the lift
- Applicable for voltage levels ranging from 110 kV to 735 kV
- Enables permanent height increases while maintaining system operability

⁴⁰ B. Kim, C. Park, S. Ban, H. Kim, “The new tower lifting method for 345kV transmission lines,” *CIGRE*, 2016.

⁴¹ L. Nazimek, S. Labocha, R. Czyż, “Development of lifting device for raising height of existing towers of overhead lines,” *CIGRE*, 2022.

This method provides a highly efficient, low-risk alternative to traditional tower modification and has been successfully deployed across various transmission networks. Table 14 provides a carbon footprint comparison between the traditional method and AMPJACK lift system-based method for a similar tower lifting project.



Figure 17: AMPJACK lift system.

Table 14: A Carbon Footprint Comparison Between the Traditional Method and AMPJACK Lift System.

		Traditional Method	AMPJACK Lift System-based Method
Materials	Concrete Trucks	24	N/A
	Steel	125,000 lbs	30,000 lbs
	Diesel Production	2,600 gal	100 gal
Equipment	Crew Truck	1	1
	Drill	1	N/A
	Bucket Truck	2	N/A
	Generator	N/A	1
	All Terrain Forklift	N/A	1
	Time	28 days	3 days

4.3 Applications and Benefits

Tower lifting is deployed under specific technical and logistical circumstances to enhance the performance of existing transmission infrastructure. Rather than building entirely new lines, often an expensive, time-consuming, and publicly contested process, tower lifting enables utilities to unlock additional capacity, ensure safety compliance, and support grid modernization using existing assets. This

section outlines key application areas where tower lifting has been effectively implemented, drawing on industry case studies and reported deployments.

4.3.1 Insufficient Transmission Line Clearance

One of the most common applications of tower lifting is to address inadequate ground clearance caused by conductor sag. As electrical current increases, the temperature of the conductor rises, causing it to expand and sag. Excessive sag can lead to violations of minimum clearance standards, posing safety risks to people, vehicles, and structures below, particularly in urban areas or across river crossings.

Tower lifting is an effective remedy in such scenarios. By raising tower heights, utilities can restore compliance with clearance regulations and allow lines to operate safely at higher thermal limits. This enables the transmission system to carry more power, especially during peak load or high-temperature conditions, without risking outages or public safety.

To address clearance violations on a 345 kV double-circuit transmission line in Michigan, ITC Holdings Corp. lifted 25 existing steel lattice towers by 10 to 20 feet. This intervention enabled the line to operate at its full design capacity without replacing the entire tower infrastructure. Compared to other alternatives such as full tower replacement or conversion to steel monopoles, tower lifting was found to be faster, more cost-effective, and less disruptive⁴².

4.3.2 ROW Constraints

Expanding the transmission grid often involves acquiring new ROW, a process that is increasingly difficult due to land use conflicts, environmental regulations, and community opposition. Tower lifting presents a practical alternative in scenarios where obtaining new ROW is economically or politically unfeasible.

By increasing tower height along existing corridors, utilities can add new circuits or upgrade existing ones without widening the corridor footprint. This approach is especially powerful when combined with reconductoring, enabling a significant increase in line transfer capacity using the existing infrastructure.

Since 2020, AMPJACK has partnered with San Francisco Public Utilities Commission (SFPUC) to lift and upgrade 115 kV double-circuit towers across environmentally sensitive and access-constrained areas, including agricultural zones, forests, and culturally significant lands. Tower lifting was selected over new line construction due to strict permitting requirements and limited site access. This method enabled capacity upgrades without expanding the environmental footprint⁴³.

⁴² “Tower Rise to the Sky”, *T&D World*, 2016. [Online]. Available: [Link](#).

⁴³ “AMPJACK Project Profile: Transmission Line Remediation Project”, *AMPJACK*, 2020. [Online]. Available: [Link](#).

4.3.3 Increasing Line Capacity

Tower lifting can directly enable increased transmission capacity by allowing conductors to operate at higher temperatures without violating clearance limits. When paired with advanced high-capacity conductors, such as HTLS conductors, the benefits are magnified. These conductors are engineered to carry more current while exhibiting minimal sag, making them ideal for maximizing grid efficiency.

Raising towers to create additional ground clearance unlocks the full potential of HTLS conductors, improving system ampacity and resilience. This approach supports the integration of renewable generation and helps meet growing electricity demand with minimal infrastructure expansion. Table 15 summarizes two projects where tower lifting has been used to increase line capacity, with and without conductor upgrades.

Table 15: Examples of Line Capacity Increase Effected Through Tower Lifting.

Project	Voltage Level	Conductor		Conductor Max Temperature		Capacity (MVA)	
		Before	After	Before	After	Before	After
AMPJACK ⁴⁴	115 kV	ACSR 54/7 1033.5 kcmil		157° F	194° F	180	240
Hydro One, Ontario ⁴⁵	115 kV	ACSR 54/7, 605 kcmil	ACSR 21/7 997.2 kcmil	185° F	302° F	136	295

4.3.4 Integration of Renewable Energy Sources

Tower lifting also plays a supportive role in the integration of renewable energy resources into the transmission grid. As utilities attempt to meet decarbonization goals and manage the growing share of variable renewable generation, such as wind and solar, transmission capacity must be expanded, often in regions far from load centers where generation occurs. However, siting new transmission lines remains a persistent challenge due to land use conflicts, permitting barriers, and environmental restrictions.

By elevating existing towers and increasing their capacity, utilities can strengthen key corridors to absorb new generation without building entirely new lines. When combined with advanced conductor technologies, such as HTLS conductors, tower lifting enables significant throughput increases within the existing footprint, providing a low-impact, cost-effective solution to grid congestion.

4.3.5 Reinforce Existing Towers

In regions exposed to extreme weather events, such as hurricanes, ice storms, or high winds, tower lifting is sometimes employed not only to raise structures but to reinforce and upgrade their load-bearing

⁴⁴ “Transmission line clearance enhancement using the AMPJACK lift system,” *CIGRE*, 2022. [Online]. Available: [Link](#).

⁴⁵ “Transmission upgrade leverages existing line,” *T&D World*, 2017. [Online]. Available: [Link](#).

capabilities. This application enhances the structural resilience of aging transmission assets, ensuring they can safely support increased conductor tension, additional circuits, or modern components.

A leading example of this dual-purpose approach is AMPJACK’s *ExoGrid* system⁴⁶. This modular steel reinforcement solution is installed externally on existing towers and enables structural strengthening in conjunction with tower lifting. ExoGrid can be configured to support:

- Additional circuit additions (e.g., new phase conductors above or below existing lines)
- Higher mechanical loads from upgraded conductors or hardware
- Enhanced performance under extreme environmental conditions
-

This integrated upgrade strategy is particularly valuable in aging transmission corridors, allowing utilities to meet modern reliability standards without replacing entire structures. It also improves grid resilience in the face of climate change-driven weather volatility.

4.3.6 Effects on Various Types of Grid Violations

Tower lifting can directly mitigate thermal violations by increasing the allowable ampacity of transmission lines. By raising tower heights, the clearance between conductors and ground is increased, which permits higher operating temperatures without breaching sag limits. This enables utilities to operate lines closer to their thermal ratings or even re-rate them, helping to alleviate congestion and reduce the number of overloads on key corridors.

In addition to resolving thermal issues, tower lifting can have secondary benefits on voltage and stability violations. Increasing transfer capacity on existing corridors improves voltage support. Table 16 summarizes the degree of impact of tower lifting technology have on addressing various grid reliability challenges.

Table 16: Degree of Impact of Tower Lifting on Grid Reliability Challenges.

Thermal Violations	Voltage Violations	Stability Violations
Notable	Minor	Minor

4.4 Technical and Operational Considerations

The utilization of tower lifting requires evaluation of various technical and operational factors to ensure proper application. This section outlines various key areas for consideration and reviews their impact on utilities.

⁴⁶ “Safer and smarter tower-raising,” *Construction in Focus*, 2024. [Online]. Available: [Link](#).

4.4.1 Analysis of Existing Lines and Towers

Tower lifting capabilities on any line depends on extensive analysis performed on the existing towers. These analyses determine both the lifting feasibility and the needed work tools and procedures. The analysis carried out involves the validation of the tower structure, foundation, and wire system. The validation procedure may involve:

- **Integrated Method 4 (Analysis between PLS-CADD, PLS-Tower and PLS-Pole):** These software tools are used together to obtain a detailed analysis of the structures, ensuring they meet safety, load-bearing and operational requirements.
- **Frame and Stress Analysis Applications:** This assessment focuses on how the tower structure responds to various unique loads and stresses, to ensure continued stability and safety. While the Frame Analysis focuses on how structural framework (vertical, horizontal and diagonal bracings) holds up under different loadings, the Stress Analysis deals with the internal stresses in the members under the loadings.

The determination of lifting feasibility through the different analysis carried out also considers other factors such as its suitability based on the circuit configuration, the clearance and weight needed for lift systems, line angles, necessary tower and foundation upgrades.

4.4.2 Desired Line Re-Rating

The goal of tower lifting as an alternative transmission technology is the upgrade of existing lines in order to increase the power transfer capacity. It is therefore vital for analysis of the desired lift to consider the desired upgrade. The new line rating may be based on the new thermal capacity (operating temperatures) of the new lines and/or the sag levels expected. This can be achieved via simulation in software tools.

Stakeholder feedback received during this project highlighted an important limitation of tower lifting. AEP noted that while tower lifting can be effective for addressing sag- or clearance-limited lines, the maximum operating temperature of many transmission lines is constrained by the physical limits of the conductor rather than tower height.

4.4.3 Utility-Wide Impact of Tower Lifting

The implementation of tower lifting introduces a variety of considerations that must be addressed across multiple departments within an electric utility. Each team is required to assess how technology influences their respective areas of responsibility. The effects of this technology may impact engineering design, protection systems, generation interconnection, system planning, and operations, each in distinct but interconnected ways. An aspect of the impact on these teams comes indirectly from the new line capacities obtained after tower lifting.

4.4.3.1 Generator Interconnection

From a generator interconnection perspective, tower lifting can serve as an effective transmission upgrade solution to mitigate thermal overloads and clearance violations identified during a SIS. By increasing ground clearance and improving line performance, tower lifting can enhance the thermal capacity of transmission lines without the need for constructing entirely new infrastructure.

Projects involving tower lifting generally fall into two primary categories, as described below and summarized in Table 17.

- **Tower Lifting without Reconductoring to Increase Line Capacity:** In this scenario, tower lifting is used independently to increase conductor ground clearance, allowing for increased thermal ratings without modifying the conductor itself. A detailed technical assessment is required to identify which structures along the corridor must be elevated. This approach typically unlocks approximately 5–50% additional transmission capacity using the existing infrastructure.
- **Tower Lifting Combined with Reconductoring to Increase Line Capacity:** In this approach, tower lifting is paired with a reconductoring project, often involving advanced conductors, to achieve higher capacity gains. The combined solution enables optimization of both electrical and mechanical performance. Careful evaluation of tower locations and conductor characteristics (e.g., weight, tension, sag) is essential. This method can deliver approximately 50–150% additional capacity over the baseline.

Table 17: Summary of Tower Lifting Implementation Scenarios.

Scenario	Design Considerations	Typical Capacity Increase
Tower Lifting without Reconductoring	Identify critical towers; assess sag clearance and thermal limits	5–50%
Tower Lifting with Advanced Conductors	Evaluate combined structural and electrical impacts; mechanical loading critical	50–150%

4.4.3.2 Transmission Planning

Similar to their role in generation interconnection, tower lifting can serve a critical function in transmission planning as an alternative mitigation strategy for thermal violations identified during reliability assessments. Once a thermal violation is identified, the effectiveness of tower lifting should be evaluated as a potential solution. Projects involving tower lifting generally fall into two primary categories, as summarized in Table 17 and Table 18, and can support annual reliability assessments in accordance with IURC’s business practices and NERC TPL-001-5.1 reliability standards.

4.4.3.3 System Protection

The enhanced ampacity and thermal ratings produced from tower lifting with upgraded conductors introduce critical changes that must be re-evaluated by the system protection team. These include:

-
- **Reassessment of Protection Settings:** As line capacities increase, protection schemes, such as relay settings and coordination, must be reviewed to ensure proper fault detection and system selectivity.
 - **Short Circuit Analysis:** Higher ampacity may influence the system during short circuit analysis, necessitating a detailed review to ensure equipment ratings, e.g. circuit breakers, remain within safe operating limits.
 - **Circuit Breaker and Switchgear Capability:** Circuit breakers and other interrupting devices must be evaluated for their ability to handle new current levels.

4.4.3.4 Operations and Control Systems

From an operations standpoint, tower lifting projects introduce both temporary and permanent changes to system conditions that must be carefully managed. During lifting activities, operators must coordinate potential planned outages, reroute power flows, and ensure system stability under altered topologies. Once the upgrade is complete, operational limits are revised, requiring updates to system monitoring tools and real-time models. Additionally, enhanced capacity may shift power flow patterns across the grid, potentially alleviating or creating new congestion points.

4.4.3.5 Engineering and Design

Implementing tower lifting has a significant impact on the work of the engineering and design teams. These include:

- **Design and Installation Requirements:** Each tower lifting operation includes extensive design and installations considerations. The different types of towers and circuits and their unique terrains contribute to the design approach for a specific tower lift. These are determined in the tower validation stage discussed in Section 4.4.1. The different towers also have unique installation characteristics, such as the safety protocols, installation procedure and installation tools. These must be integrated into the planning and design for the team.
- **Training and Procedure Development:** Installation crews must also receive proper training in the specific lifting approach determined. Enhanced procedures must be developed to mitigate the risk of installation-related failures.
- **Structural Assessment and Upgrades:** Engineering teams must also assess and determine which existing transmission structures, foundations, and associated hardware can support and benefit from tower lifting. In many cases, structural reinforcement or equipment replacement may be necessary to accommodate new loading or tension requirements.

4.4.3.6 Summary of Utility-Wide Impacts

Table 18 summarizes the impact of tower lifting across various utility departments.

Table 18: Utility-Wide Impacts of Tower Lifting.

Utility Function	Impact Level	Primary Benefits of Tower Lifting Deployment
Generation Interconnection	High	Provides an efficient and cost-effective solution to mitigate thermal overloads and clearance violations identified during a SIS.
Transmission Planning	High	Offers a flexible mitigation option to address thermal violations in annual reliability assessments with limited requiring new ROW.
System Protection	Low	Requires review and possible updates to protection settings, short circuit analysis, and breaker capabilities due to increased line capacity.
Operations and Control	Moderate	Impacts real-time operations, including outage coordination, system modeling updates, and changes in power flow patterns.
Engineering and Design	High	Requires comprehensive assessment of tower structures, development of custom lifting designs, and updated installation training and protocols.

4.5 Best Practice

The successful implementation of tower lifting projects offers valuable lessons for optimizing existing transmission infrastructure. Although each power system has its own unique challenges, several consistent strategies have emerged from completed projects. This section summarizes industry-recognized best practices for deploying tower lifting technology, categorized by the primary project drivers, congested urban ROW or reliability enhancement, as well as key considerations based on voltage levels.

4.5.1 Congested Urban ROW

Although all tower lifting projects have a goal of upgrading the existing transmission lines in some form, this section focuses on upgrades that are uniquely necessitated by the constraints of ROW in densely populated urban areas. This way, the secondary goal is safety and reliability of the line in these areas. Such areas are challenged not only by ROW but also by the possible construction sequencing during execution.

The first step is auditing the tower and foundations to determine the existing capacities (residual capacities) to determine the feasible extent of the lift. These assessments must also account for minimum code clearances required by regulatory bodies such as the Federal Aviation Administration (FAA). Detailed design of the new towers as well as the needed retrofits of foundations and towers must consider the

unique constraints in the areas. Typically, such projects are also favorable for reconductoring with low sag conductors.

AMPJACK completed the 115 kV SouthEast Massachusetts-Rhode Island-Area 1 Improvement Program for National Grid in the congested urban ROW in Fall River, MA⁴⁷, involving the reuse and retrofitting of 95-year-old towers. The project included reconductoring with ACCC conductors to increase capacity within a congested urban corridor.

Hydro One implemented lightweight shaft extensions above the tower waistline to double the power-transfer capacity of a 90-year-old transmission line in heavily populated urban and industrial areas. This innovative approach minimized construction disruption and reduced project costs and timelines.

4.5.2 Reliability Enhancement

Tower lifting serves as an effective strategy for enhancing the reliability of transmission systems, particularly in meeting regulatory standards such as those set by the North American Electric Reliability Corporation (NERC). By increasing ground clearance and accommodating higher-capacity conductors, utilities can address thermal constraints and improve system resilience.

Two key factors in upgrading reliability will be the cost and the speed of implementation, with minimal compromise to other areas such as the environment. This way, tower lifting is considered a way of attaining substantial cost saving compared to traditional construction. The project duration in this case is also significantly lower.

AMPJACK completed 40 tower raises on a 230 kV double-circuit transmission lines for the Western Area Power Authority (WAPA) in 2015/2016. The structures were raised by 5 feet and 8 feet heights to gain the needed clearance for the NERC requirements. This was considered a low cost and faster solution as compared to the reconstruction of a new line with about 40 towers.

ITC Holdings Corp. faced clearance issues on a 345 kV double-circuit transmission line between Argenta and Palisades in Michigan. The line had been derated due to excessive sag, limiting its capacity to meet growing demand. To address this, ITC Holdings Corp. evaluated the following three options:

- Replacing existing steel lattice towers with new lattice towers
- Replacing existing towers with new steel monopoles
- Raising existing steel lattice towers using extensions

After assessing factors such as service disruption, reliability impacts, and costs, ITC Holdings Corp. decided on the third option above. They successfully raised 25 steel lattice towers by 10 to 20 feet each,

⁴⁷ “SouthEast Massachusetts - Rhode Island – Area 1 Improvement Program,” AMPJACK. [Online]. Available: [Link](#).

enabling the line to operate at its design rating. This solution proved to be time-efficient and cost-effective, avoiding the complexities associated with new construction.

4.5.3 Voltage Levels

Voltage levels play a significant role in determining the methods, tools, and design considerations involved in tower lifting projects. For lower voltage lines, such as those at 115 kV and 138 kV, tower lifting is commonly applied in urban and semi-urban environments where ROW constraints are a major concern. These projects often involve aged infrastructure that requires modernization, typically paired with reconductoring using low-sag or high-temperature conductors. The tower lifting process in these settings must also account for reduced access, limited workspace, and safety measures appropriate for populated areas.

In contrast, mid-range voltage levels, particularly at 230 kV and 345 kV, are often targeted for reliability upgrades and capacity improvements to meet NERC facility rating requirements. These projects can occur in both urban and rural locations, often present a balance between complex site logistics and more manageable tower modifications. Utilities at such voltage levels have successfully used tower lifting to address clearance violations and to enable upgraded conductor systems without the need for entirely new transmission structures, thus saving significantly on cost and time.

For higher voltage levels, such as at 500 kV, tower lifting projects become more technically demanding. These projects often occur in rural or remote environments, such as mountainous or heavily vegetated areas. The scale of lifting is larger, involving substantial structure weight and greater tower height adjustments. Due to the importance of maintaining reliability on high-voltage backbones, many such projects are performed under energized conditions to avoid service interruptions. The engineering requirements are also more strict, including deeper foundation assessments, dynamic stability analyses, and more robust construction sequencing.

At the highest voltage levels, such as at 735 kV, tower lifting operations are relatively rare but not unprecedented. These projects are typically situated in very remote areas and must account for extreme mechanical loading and challenging terrain. Lifting operations at this scale often require highly specialized equipment and construction methods tailored to large net lift weights, which can exceed 120,000 lbs. Environmental considerations are also paramount, with a focus on minimizing impacts on protected ecosystems and critical habitats. The complexity and cost of such projects necessitate careful cost-benefit analysis, yet they remain a valuable alternative to new construction in sensitive or inaccessible regions.

AMPJACK restored 15 critically damaged and leaning towers on a remote 110 kV double-circuit transmission line in SaskPower. The project overcame challenges such as difficult access and unpredictable subsurface conditions, ensuring the ongoing reliability of the transmission line.

In New Hampshire, Eversource performed a 345 kV tower lifting project to resolve thermal clearance violations identified during a line rating assessment. The project involved raising multiple lattice towers

by approximately 15 feet each to meet NERC FAC-008 compliance, allowing the line to operate at its full design rating. Because the line was a critical corridor, energized lifting methods were employed to avoid outages, and coordination with ISO-NE was essential throughout the planning process.

AMPJACK executed a significant 735 kV tower raising project in Hydro-Québec, involving 50 energized tower lifts on two critical transmission lines. The project utilized the AMPJACK tower lifting system to perform 5 feet and 10 feet lifts on four unique tower types, enhancing capacity while maintaining service continuity.

4.6 Challenges and Barriers

Despite the numerous benefits and successful deployments of tower lifting across various utilities, several persistent challenges continue to limit its widespread adoption. These obstacles span technical, financial, operational, and regulatory domains and require coordinated planning, innovation, and collaboration across the utility industry to overcome.

4.6.1 High Initial Cost

Tower lifting projects involve specialized equipment, engineering analysis, and skilled labor, all of which contribute to high upfront costs. This includes cranes, helicopters (in traditional methods), or proprietary lifting systems, along with the design modifications and permitting processes needed for each lift. However, advancements in tower lifting technologies, such as modular systems like AMPJACK, are helping to reduce overall costs, particularly when compared to full transmission line reconstruction.

4.6.2 Complexity of Existing Infrastructure

In many cases, transmission networks are complex, with existing towers and poles located in challenging positions or in areas with limited access. Lifting these towers while ensuring that no damage is done to the existing infrastructure, such as power lines or other components, can be very complicated. More so, validation of existing tower residual capacity could reveal complicated retrofits to the foundation and structure.

4.6.3 Regulatory and Permitting Constraints

Tower lifting often requires regulatory approval from bodies such as FERC, NERC, EPA and FAA, and these can be a lengthy process. Permitting can be especially challenging in environmentally sensitive areas, urban locations, or areas with specific zoning laws. This can delay or even prevent the implementation of tower lifting as a solution.

4.6.4 Safety Concerns

Lifting towers, especially energized lifts, presents significant safety risks to workers and surrounding infrastructure. The potential for accidents during these operations requires strict safety protocols and

thorough procedural planning, which can add complexity and time to the project. It is important to note that each tower lifting activity is unique due to the specific terrain and site conditions involved.

4.6.5 Environmental and Terrain Limitations

Challenging terrain and extreme weather conditions can restrict tower lifting operations or demand additional logistical measures. For instance, mountainous or marshy environments may require aerial delivery of materials, while high winds or snow loads can delay operations or necessitate structural enhancements. These constraints often necessitate site-specific adaptations that increase project scope and duration.

4.7 Modeling Procedure

The implementation of tower lifting into transmission systems necessitates several updates in system modeling, which directly impact system behavior under steady state, short circuit, and dynamic conditions.

4.7.1 Steady State Model

In steady state power flow modeling, normal and emergency ampacity limits must be updated to reflect the increased thermal rating made possible by tower lifting. In addition, tower lifting alone, when not paired with conductor upgrades, has a negligible impact on the line impedance and typically only affects the line susceptance, see Figure 18.

4.7.2 Dynamic Model

In transient stability studies, tower lifting may necessitate updates to line rating, to accurately reflect dynamic performance. The changes in line parameters will be revised in power flow models, as mentioned in Steady State Model.

4.7.3 Short Circuit Model

In short circuit studies, tower lifting does not materially alter the line's electrical configuration or conductor properties, unless reconductoring is involved. Thus, the line impedance remains effectively unchanged, and no significant modeling updates are typically needed.

Branch Data Record

Power Flow
Short Circuit

Basic Data

From Bus Number
99991
From Bus Name
BUS A
345.00
In Service

To Bus Number
99992
To Bus Name
BUS B
345.00
Metered on From end

Branch ID
Z
Branch Name

Branch Data

Line R (pu)
0.001760
Line X (pu)
0.012920
Ratings (I as MVA)
RATE1
1894.0
RATE2
2081.0
RATE3
0.0
RATE4
0.0
RATE5
0.0

Charging B (pu)
2.142170
Length
100

Line G From (pu)
0.00000
Line B From (pu)
0.00000

Line G To (pu)
0.00000
Line B To (pu)
0.00000

Owner Data

Owner
Fraction

111
Select ...
1.000

0
Select ...
1.000

0
Select ...
1.000

0
Select ...
1.000

OK
Cancel

Figure 18: Line Parameters in PSS/E Power Flow Model.

5. Static Synchronous Compensators

5.1 Introduction

The modern power grid is undergoing a transformative shift as renewable energy resources such as wind and solar become increasingly integrated into the energy mix. While these resources offer environmental benefits and sustainability, their inherent intermittency and variability introduce complexities in maintaining grid stability and reliability. Traditional power systems, designed for predictable and controllable generation, now face challenges in accommodating the fluctuating nature of renewable energy resources. This necessitates innovative solutions to ensure seamless integration without compromising the grid's operational integrity.

One of the primary concerns with high renewable energy resources penetration is the requirement for sufficient transfer capability to deliver generated power from often remote locations to consumption centers. This has traditionally led to the consideration of extensive transmission system upgrades, which are capital-intensive and time-consuming. However, an alternative approach lies in the deployment of ATTs, which aim to optimize the existing infrastructure's capacity and performance. ATTs encompass a range of devices and tools designed to address various operational challenges, including congestion management, voltage regulation, and stability enhancement.

Among the prominent ATTs, FACTS have gained significant attention. These power electronic-based devices offer dynamic control over power flow and system parameters, thereby enhancing the grid's flexibility and responsiveness. Within the FACTS family, the Static Synchronous Compensator (STATCOM) stands out for its ability to provide rapid and precise reactive power support. By injecting or absorbing reactive power, STATCOMs help maintain voltage levels within desired ranges, crucial for the reliable operation of power systems, especially under the influence of variable renewable energy resources outputs.

STATCOMs operate using VSCs equipped with advanced semiconductor technologies, such as IGBTs⁴⁸. They are shunt-connected power electronic devices primarily designed to provide dynamic capacitive/inductive power support. This configuration allows for immediate response times and fine-tuned control over reactive power compensation. STATCOMs can generate both reactive and inductive output current independent of the system voltage⁴⁹ and have better dynamic response capability than alternative methods for reactive power support such as Static Var Compensators (SVCs). Compared to SVCs, STATCOMs offer superior performance, particularly in scenarios involving rapid voltage fluctuations

⁴⁸ "Static synchronous compensator (STATCOM)," *ENTSO-E*, 2025. [Online]. Available: [Link](#).

⁴⁹ "STATCOM: future-proofing reactive power compensation," *GE Vernova*, 2024. [Online]. Available: [Link](#).

and low system voltages. Their compact design and reduced need for harmonic filters further contribute to their appeal in modern grid applications.

This chapter provides a reference for STATCOM implementation. The subsequent sections investigate technical configurations, operational principles, and mathematical models underpinning STATCOM functionality. The diverse applications and benefits of STATCOMs in enhancing grid reliability and facilitating renewable energy resources integration are reviewed as well. Furthermore, key technical considerations for deployment are discussed, along with real-world case studies demonstrating their efficacy and the challenges associated with their adoption. Finally, the report concludes with modeling approaches essential for accurately representing STATCOMs in power systems studies, such as steady state, short circuit, and dynamic stability studies.

5.2 Technology Background

STATCOMs are shunt-connected power electronic devices primarily designed to provide dynamic capacitive/inductive power support. Their ability to rapidly inject or absorb reactive power makes them highly effective for stabilizing voltage levels in modern power systems. STATCOMs are particularly beneficial in grids with high levels of renewable energy integration, where fluctuations in generation can pose significant voltage stability challenges. This section presents a detailed overview of the STATCOM's configuration, components, and operational principles, as well as its mathematical modeling fundamentals.

5.2.1 STATCOM Configuration

A STATCOM is based on a VSC that can generate controllable output AC voltage. This voltage is synchronized with the grid and can be varied in magnitude and phase angle to inject or absorb reactive power. A basic STATCOM system consists of the following components, as shown in Figure 19⁵⁰:

- **VSC:** The VSC is used to convert the input DC voltage to an output AC voltage. Two of the common VSC types are:
 - Gate Turn-Off Thyristors: In this type, the output AC voltage is controlled by changing the input voltage of a DC capacitor, as the fundamental component of the converter output voltage is proportional to the DC voltage.
 - Insulated Gate Bipolar Transistors: In this type, a Pulse Width Modulation (PWM) technique is used to generate a sinusoidal waveform from a DC voltage source with a typical chopping frequency of a few kHz. Unlike the Gate Turn-Off Thyristors-based approach, this type utilizes a fixed DC voltage and varies its output AC voltage by changing the modulation index of the PWM modulator.

⁵⁰ "Reliability guideline reactive power planning," NERC, 2016. [Online]. Available: [Link](#).

- **DC Capacitor:** DC Capacitor is used to supply constant DC voltage to the VSC.
- **Interface Reactor:** Connects the VSC to the AC grid and serves two purposes: it limits harmonic currents and provides smooth current transitions.
- **Coupling Transformer:** Steps up the voltage to grid level and isolates the STATCOM from the system.

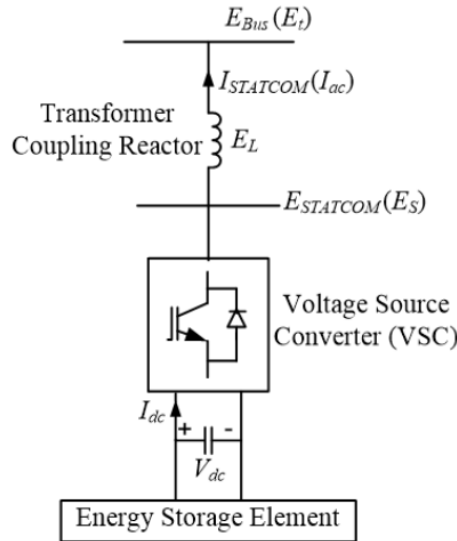


Figure 19: STATCOM Configuration.

5.2.2 Operating Principle of STATCOM

In the schematic diagram of STATCOM shown in Figure 19, E_t is the bus voltage of the transmission system, $E_{STATCOM} (E_s)$ is the 3-phase output voltage of the STATCOM, and $I_{STATCOM} (I_{ac})$ is the injected AC current of the STATCOM, and E_L is the voltage across the transformer coupling reactor. The exchange of reactive power between the VSC and AC system can be achieved by varying the amplitude of the 3-phase output voltage of the STATCOM (E_s), as:

- If $E_s > E_t$ then the AC current (I_{ac}) flows from the VSC to the AC system. In this case, the injected AC current (I_{ac}) is 90° leading to the bus voltage (E_t) of the system (E_t). So, STATCOM can supply capacitive reactive power to the AC system.
- If $E_s < E_t$ then the AC current (I_{ac}) flows from the AC system to the VSC. In this case, the injected AC current (I_{ac}) is 90° lagging to the bus voltage (E_t) of the system (E_t). So, the STATCOM can absorb inductive reactive power from the AC system.
- If $E_s = E_t$ then the reactive power exchange is zero. So, the STATCOM is in a floating state.

Figure 20 shows the V-I characteristics of STATCOM. It shows that the STATCOM can operate to supply both capacitive and inductive reactive powers, typically, between 3 to 300 MVAR. Also, STATCOM can provide full capacitive reactive power for any system voltage even for 0.2 per unit. In the capacitive region, the maximum transient current is determined by the maximum current turn-off capability of the VSC

switches. In the inductive region, the maximum transient current is determined by the maximum allowable junction temperature of the VSC switches.

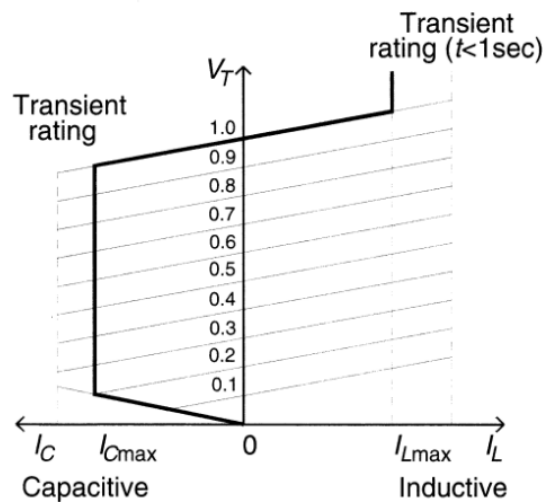


Figure 20: V-I Characteristics of STATCOM.

5.2.3 Operating Modes of STATCOM

STATCOMs operate in multiple modes depending on grid requirements:

- **Voltage Regulation Mode:** Adjusts reactive power output to maintain bus voltage at a specified setpoint.
- **Power Factor Correction Mode:** Adjusts reactive output to maintain a desired power factor at the point of connection.
- **Standby or Idle Mode:** Monitors grid conditions without injecting or absorbing power until needed.

5.3 Applications and Benefits

STATCOMs are flexible power electronic devices that provide dynamic reactive power support, enhancing voltage stability and power quality across various segments of the electrical grid. Their rapid response and precise control capabilities make them invaluable in modern power systems, especially with the increasing integration of renewable energy resources and the growing complexity of industrial loads⁵¹. This section explores the key applications and benefits of STATCOM deployments in both transmission networks and industrial settings, followed by an analysis of their role in mitigating different types of grid violations.

⁵¹ "NERC: loss of reactive power, voltage instability likely outcome from geomagnetic disturbance effects," *POWER Magazine*, 2012. [Online]. Available: [Link](#).

5.3.1 Transmission Line Application

In transmission systems, STATCOMs play a pivotal role in maintaining voltage stability, enhancing power transfer capacity, and improving overall grid reliability. Their applications include:

- **Real-Time Voltage Control:** STATCOMs provide immediate reactive power support, enabling precise voltage regulation at critical buses in the transmission network. This capability is essential for maintaining voltage levels within permissible limits during varying load conditions and contingencies.
- **Grid Stability Enhancement:** By supplying or absorbing reactive power rapidly, STATCOMs help dampen power oscillations and improve transient stability during disturbances such as line faults or sudden load changes. This contributes to the prevention of cascading failures and blackouts.
- **Increased Power Transfer Capability:** STATCOMs can effectively increase the power transfer limits of existing lines by improving voltage profiles and reducing voltage drops along the lines.
- **Reduction of Transmission Losses:** By optimizing reactive power flow and maintaining voltage levels close to nominal values, STATCOMs help minimize losses in transmission lines, thereby improving overall system efficiency.
- **Support for Renewable Integration:** With the growing penetration of renewable energy resources, STATCOMs assist in managing the associated variability and intermittency by providing fast-acting voltage support, thus facilitating the stable integration of renewables into the grid.

5.3.2 Industrial Users Application

In industrial settings, particularly those with large and dynamic loads, STATCOMs offer significant benefits in maintaining power quality and operational efficiency:

- **Power Quality Improvement:** Industrial loads often consist of equipment that introduces voltage fluctuations and harmonics. STATCOMs mitigate these issues by providing dynamic reactive power compensation, thereby stabilizing voltage levels and reducing harmonic distortion.
- **Unbalance Correction:** In facilities with asymmetrical loads, STATCOMs configured with delta connections can effectively correct phase-to-phase voltage unbalances, ensuring balanced power supply and protecting sensitive equipment.
- **Flicker Mitigation:** Loads such as electric arc furnaces cause rapid and severe power fluctuations, leading to voltage flickers. STATCOMs counteract these effects by immediately adjusting reactive power output, thus stabilizing voltage and improving equipment performance.
- **Power Factor Correction:** By dynamically adjusting reactive power flow, STATCOMs help maintain a desired power factor, reducing penalties from utility companies and enhancing the efficiency of power usage in industrial plants.

5.3.3 Effects on Various Types of Grid Violations

STATCOMs are instrumental in addressing several types of grid violations, such as thermal, voltage, and stability violation, in transmission networks.

5.3.3.1 Thermal Violations

Thermal violations occur when transmission lines or equipment operate beyond their thermal capacity, often due to excessive current flow. While STATCOMs do not directly reduce current magnitudes, they indirectly alleviate thermal stress by:

- **Enhancing Voltage Profiles:** Improved voltage levels reduce the reactive power demand from the grid, thereby decreasing the total current flow through transmission lines.
- **Optimizing Power Flow:** By managing reactive power locally, STATCOMs reduce the need for reactive power to be transmitted over long distances, thus lowering line loading and associated thermal stress.

5.3.3.2 Voltage Violations

STATCOMs contribute to voltage stability enhancement through by^{52,53}:

- **Dynamic Voltage Regulation:** STATCOMs immediately inject or absorb reactive power to counteract voltage sags or swells, maintaining voltage within acceptable limits.
- **Voltage Support in Weak Grids:** In areas with weak grid connections or high renewable penetration, STATCOMs provide necessary voltage support to ensure stable operation.
- **Improved Voltage Recovery:** After fault clearance, STATCOMs aid in the rapid restoration of voltage levels, minimizing the risk of delayed voltage recovery phenomena.

5.3.3.3 Stability Violations

STATCOMs contribute to stability enhancement through:

- **Transient Stability Support:** During disturbances, STATCOMs provide rapid reactive power compensation, helping to maintain voltage levels and prevent system collapse.
- **Oscillation Damping:** By modulating reactive power output in response to system oscillations, STATCOMs dampen power oscillations and enhance dynamic stability.
- **Fault Ride-Through Capability:** STATCOMs assist in maintaining voltage stability during faults, enabling critical loads and generators to remain connected and operational.

⁵² F. Dong, b. Chowdhury, M. Crow, L. Acar, "Improving voltage stability by reactive power reserve management," *IEEE Transactions on Power Systems*, 2005.

⁵³ A. Wampack, "Reactive power and the energy transition, explained," *Withthegrid*, 2025. [Online]. Available: [Link](#).

5.3.4 Summary of STATCOM Impact on Grid Concerns

Table 19 summarizes the degree of impact STATCOMs have on addressing various grid reliability challenges.

Table 19: Degree of Impact of STATCOMs on Grid Reliability Challenges.

Thermal violations	Voltage Violations	Stability Violations
Marginal	Notable	Notable

5.4 Technical and Operational Considerations

The successful deployment of STATCOMs in power systems depends not only on the technology itself but also on a general understanding of system requirements, coordination strategies, and operational integration. This section outlines key considerations related to site selection, sizing, control strategy, and system compatibility to ensure optimal performance and long-term reliability of STATCOM installations.

5.4.1 Technology Implementation Assessment

Implementing STATCOMs effectively within a transmission network involves addressing several key technical challenges related to their optimal placement and sizing. This process typically begins with detailed system studies, including power flow analysis, contingency analysis, and dynamic stability simulations, to identify voltage-weak areas where STATCOM support would provide the greatest benefit. Advanced optimization techniques can also be applied to determine ideal locations and ratings, guided by objective functions such as voltage deviation minimization and stability margin improvement. These technical assessments must be integrated with cost-benefit analyses that account for capital costs, operational savings, and the deferral of larger infrastructure upgrades.

5.4.2 Operation and Control Considerations

A critical consideration of STATCOM implementation is to ensure effective operation and control across various system conditions. STATCOMs must be capable of operating in different reactive power control modes, such as voltage control, power factor control, or reactive power setpoint mode, depending on real-time system requirements. Seamless integration with the EMS and SCADA platforms is essential for enabling real-time monitoring, dispatch, and automated control. Furthermore, coordination with other grid assets, including capacitor banks, synchronous condensers, and additional FACTS devices, is necessary to support complementary or hierarchical control strategies that optimize system stability and performance.

5.4.3 Protection and Reliability Considerations

Ensuring robust protection and high reliability is essential for effective STATCOM implementation. Comprehensive protection schemes must be integrated to safeguard the equipment against conditions

such as overvoltage, overcurrent, DC link overvoltage, and system faults, with protective relays designed to detect and isolate disturbances promptly to prevent damage. Reliability can be further enhanced through the use of modular multi-level converters (MMC) and redundancy strategies that improve fault tolerance and minimize operational downtime. Additionally, maintaining high availability requires regular maintenance practices, including scheduled inspections, firmware updates, and proactive management of component life cycles to ensure sustained performance and system dependability.

5.4.4 Utility-Wide Impacts of STATCOM Deployment

The integration of STATCOMs affects key areas within a utility, including generation interconnection, transmission planning, system protection, operations, and engineering design. A comprehensive understanding of the role and impact of STATCOMs across utility departments is essential for effective deployment, operational reliability, and long-term system planning. This section outlines the specific considerations each department must account for when integrating STATCOMs into the power grid.

5.4.4.1 Generation Interconnection

As discussed in Section 5.3, STATCOMs enhance grid stability by dynamically injecting or absorbing reactive power in response to disturbances such as faults, load fluctuations, or variability from renewable energy sources. This fast-reacting capability makes STATCOMs particularly effective in mitigating transient and voltage stability violations frequently encountered in transmission planning studies.

Once a voltage stability issue is identified, a root cause analysis should be conducted to determine the underlying source. If the issue is confirmed and originates from the steady-state model, further investigations are necessary to identify appropriate steady-state mitigation measures. If the required reactive power support exceeds the capacity of standard switched shunt devices, leading to a recommendation for a line upgrade or new build, a STATCOM may present a viable alternative. STATCOMs typically provide significantly higher MVAR capacity along with rapid dynamic response, which can potentially eliminate the need for constructing new transmission lines.

If the voltage stability issue originates from the dynamic model and is genuinely caused by insufficient fast-reactive power support, a STATCOM may be an effective mitigation option. However, if the area has significant potential for load or generation growth, limited short-circuit strength, and requires substantial reactive power support, a transmission project may ultimately be more appropriate. Otherwise, if the reactive power requirement is within a practical range for a STATCOM, its fast dynamic response can potentially resolve the observed voltage stability issues.

In the context of voltage violations, here are some insights for consideration in STATCOM implementation:

- STATCOMs might be a feasible solution for **voltage limit violations** as well as **voltage deviation violations**, identified in steady-state studies, particularly when high reactive power support is needed. STATCOM might not be a feasible alternative once the reactive power support is higher than their typical range (higher than 400-500 MVARs). In those scenarios, conventional transmission solutions might be feasible to enhance weak grid areas.
- For steady-state voltage violations identified during large load interconnection studies, if the dynamic model provided for load facility is not fully trustable, STATCOMs might be a more realistic solution than switched-shunts.
- STATCOMs might be a feasible solution for **voltage recovery transient (peak-to-peak ratio)** violations, due to their fast response.
- STATCOMs might be a feasible solution for the case of **notable voltage drop/peak**, that might lead to multiple generation unit trappings, due to their fast response.
- In case of **simulation crashing** due to voltage collapse, either in steady-state or dynamic simulations, depending on the size and nature of the issue, STATCOMs might be a cost-effective alternative compared to conventional solutions such as building a new transmission line.
- STATCOMs might enhance voltage recovery in the case of **voltage oscillation or slow recovery** due to their fast response.
- STATCOMs might not be a feasible solution for in case of voltage violation in grid with low short-circuited ratio.

5.4.4.2 Transmission Planning

Based on the discussions in Generation Interconnection Section, in the context of NERC Standard TPL-001-5.1, particularly Requirements R4 and R5, which focus on voltage stability and transient stability analyses under a wide range of contingency conditions, STATCOMs offer fast-acting voltage support that can significantly improve both transient and dynamic system performance. Additionally, under CIP-014-3, which requires assessments of reactive power margins, STATCOMs can be considered as part of the mitigation strategy. Their rapid response and voltage-regulating capabilities can help maintain operational resilience even under stressed system conditions or potential loss of critical assets.

5.4.4.3 System Protection

The implementation of shunt FACTS devices can negatively impact on the performance of distance relays. The impacts include under/over-reaching, delayed response and incorrect phase selection. The system protection department should pay close attention to these issues and make sure that protection mechanisms function properly in the presence of STATCOMS.

The integration of shunt FACTS devices such as STATCOMs can introduce challenges for traditional protection schemes, particularly distance relays. The presence of STATCOMs can alter the impedance seen by relays, leading to potential delayed relay response, and incorrect phase selection during fault conditions. These effects are primarily due to the dynamic injection or absorption of reactive power, which changes the voltage and current profiles near the STATCOM's point of interconnection.

Given these challenges, it is essential that the system protection department conducts thorough evaluations to ensure that protective relaying schemes remain effective and reliable in the presence of STATCOMs. This may involve relay coordination reviews, dynamic simulations, and adjustments to relay settings or logic to account for the STATCOM's influence. Coordination with manufacturers and use of advanced relay models that account for power electronic behavior may also be necessary.

5.4.4.4 Operations and Control Systems

STATCOM deployment introduces several important considerations for system operations:

Optimization and Control: To fully leverage the fast-response capabilities of STATCOMs, accurate and detailed modeling must be incorporated into power system operation and optimization tools. Real-time adjustments to device setpoints in response to voltage fluctuations, load changes, or contingencies are critical to ensure effective dynamic voltage support. With the emergence of mobile and relocatable STATCOM units, operational complexity increases further due to the need for dynamic placement strategies. System operators should collaborate with STATCOM vendors to ensure the availability of compatible control interfaces and models that integrate seamlessly with existing SCADA, EMS, and dynamic simulation environments.

Maintenance and Upgrades: STATCOMs require continuous health monitoring to maintain reliability and performance. Establishing a preventive maintenance program is essential to detect potential faults, degradation in performance, or wear in power electronic components. In response to changes in system topology or load patterns, periodic reviews and hardware or firmware upgrades may be necessary to align STATCOM capabilities with evolving grid needs.

5.4.4.5 Engineering and Design

Compared to SVCs, STATCOMs offer a more compact footprint, making them suitable for installations with limited available space. However, site-specific engineering requirements must still be thoroughly addressed. This includes:

- **Site Preparation:** The area must be cleared and properly graded. Engineering teams must design and implement appropriate infrastructure, including foundations, grounding systems, drainage, fencing, and cable trenches to accommodate the STATCOM's components and ensure electrical safety.

- **Compliance and Safety Assurance:** The engineering and design team must verify that all equipment testing and commissioning activities meet applicable safety protocols, utility standards, and regulatory requirements.

5.4.4.6 Summary of Utility-Wide Impacts

Table 20 summarizes the impact of STATCOMs across various utility departments.

Table 20: Utility-Wide Impacts of STATCOMs.

Utility Function	Impact Level	Primary Benefits/Impacts of STATCOMs Deployment
Generation Interconnection	High	Mitigates steady-state and dynamic voltage stability issues, avoids costly upgrades.
Transmission Planning	High	Improves voltage and transient stability under TPL-001-5.1, supports CIP-014-3 compliance, serves as a flexible alternative to new transmission lines.
System Protection	Medium	Can impact relay performance; requires updated relay coordination, protection settings, and advanced modeling to ensure proper fault detection and response.
Operations and Control	Medium to High	Enables real-time voltage regulation, supports dynamic grid conditions, requires SCADA/EMS integration, preventive maintenance, and may involve mobile unit placement and control strategies.
Engineering and Design	Medium	Offers compact installation footprint, but requires detailed site preparation, grounding, compliance assurance, and adherence to safety and regulatory standards during installation and commissioning.

5.5 Best Practice

The successful deployment of STATCOMs across various utilities provides a wealth of practical insights and lessons for future implementation. This section highlights selected projects where STATCOMs have been installed to address voltage stability, reactive power support, and grid modernization challenges. These examples demonstrate how system needs can be effectively addressed through dynamic reactive power compensation. They also reveal critical design, engineering, and operational considerations that contribute to project success.

5.5.1 Los Angeles Department of Water and Power (LADWP)⁵⁴

Siemens Energy supplied a reactive power compensation plant to the LADWP. The plant enhanced operations at Barren Ridge Switching Station, LADWP's renewable energy transmission facility in Kern

⁵⁴ "Siemens Energy's reactive power compensation technology helps advance CO 2-free power supply in California," *Siemens Energy*, 2021. [Online]. Available: [Link](#).

County, California, about 80 miles north of Los Angeles. The plant combines the benefits of STATCOM and modular multi-level converter (MMC) technology. The ± 200 MVAR STATCOM will provide the necessary voltage support needed in the area, where LADWP has significantly increased renewable energy generation.

5.5.2 Pacific Gas & Electric (PG&E) - Orchard Substation Project⁵⁵

The Orchard Substation project in Huron, California, stands out as the largest STATCOM installation in North America, with a capacity of ± 800 MVAR. This project was driven by the need to strengthen grid stability and reliability in California's Central Valley, particularly in support of PG&E's nearby Gates Substation. The STATCOM enhances voltage control and supports power transfer across the region's high-voltage network, which faces increasing demands from renewable integration and load growth. The project highlighted the ability of large-scale STATCOM installations to provide rapid, dynamic reactive power support and delay or avoid the need for costly transmission upgrades, offering a practical path to modernizing grid infrastructure amid growing operational complexity.

5.5.3 Pacific Gas & Electric (PG&E) - Round Mountain Project⁵⁶

The Fern Road STATCOM Project, proposed by LS Power Grid California (LSPGC) in its CPUC application (A.22-04-004), involves the construction of a new ± 529 MVAR dynamic reactive support substation east of Fern Road in Shasta County. The project includes a minimum of two equally sized STATCOM units, looped into PG&E 500 kV Round Mountain–Table Mountain transmission lines. This installation was identified through the California Independent System Operator (CAISO) 2018–2019 Transmission Planning Process as necessary to address high-voltage conditions and dynamic stability issues in the region. The STATCOMs will help maintain grid reliability amid increasing system volatility, particularly in areas with limited reactive support. Lessons learned emphasize the strategic site selection of STATCOMs near key transmission nodes to provide localized dynamic voltage control, and the importance of early coordination with ISO planning processes and environmental permitting to streamline implementation.

5.5.4 Yukon Energy Corporation - Canada⁵⁷

The Stewart Crossing South Substation project in Yukon, Canada, features a ± 15 MVAR STATCOM system provided by Hitachi Energy. The project was driven by the need to address voltage stability challenges in a remote section of the transmission grid, particularly under high load conditions or during disturbances. The STATCOM ensures dynamic voltage support, helping maintain power quality and reliability in the region's harsh and sparsely populated environment. One of the key lessons learned was the critical role

⁵⁵ "LS power grid california energizes orchard substation," *LSPower*, 2025. [Online]. Available: [Link](#).

⁵⁶ "Round mountain 500 kV area dynamic reactive support project," *LSPower*, 2025. [Online]. Available: [Link](#).

⁵⁷ B. Korbutiak, A. Spachynski, N. Costa, R. Isbister, "Application of static synchronous compensator (STATCOM) on the Yukon integrated system," *CIGRE*, 2022.

of modular design and factory testing in minimizing site installation time and ensuring reliable performance under cold weather conditions. The deployment demonstrated how advanced reactive power compensation can effectively reinforce weak grid areas, supporting both current demands and future expansion, including potential renewable energy integration.

5.5.5 German Transmission System Operator - Amprion⁵⁸

Amprion commissioned Siemens Energy with the construction of two STATCOMs to further stabilize the German transmission power grid. The plants are in Polsum (North Rhine-Westphalia) and Rheinau (Baden-Württemberg). Both systems are designed for a reactive power range of ± 600 MVAR making them among the most powerful systems in the world. In addition, the STATCOMs feature innovative grid-supporting control mechanisms allowing the systems to efficiently compensate for increasing voltage fluctuations in the electrical transmission network.

5.5.6 Lessons Learned

Real-world implementations of STATCOMs have uncovered key engineering and operational insights that inform the best practices:

- **Auxiliary Power Redundancy:** In one case, a STATCOM tripped offline following the loss of its auxiliary cooling system power during a grid voltage disturbance, ultimately resulting in the shedding of 92 MW of load. The solution involved installing an uninterruptible power supply to ensure continuous operation of STATCOM auxiliary systems. This incident underscores the need to isolate critical support systems from grid events the STATCOM is meant to mitigate, emphasizing robust and redundant auxiliary power design.
- **Connection Integrity and Fire Risk:** A cable connection malfunction caused a significant fire at a STATCOM site only two weeks after commissioning, leading to damage not only to the STATCOM unit but also nearby equipment such as transformers. This event highlights the importance of thorough pre-commissioning inspections, quality assurance testing, and fault-tolerant installation practices to prevent catastrophic failures.
- **Environmental and Site Preparedness:** Several projects showed that environmental and physical site conditions, such as space constraints, grounding adequacy, and weather exposure, must be addressed early in design. In cold or remote environments, modular construction and factory acceptance testing were shown to reduce commissioning risks and delays.

These lessons reinforce the importance of proactive planning, resilient system design, and thorough testing protocols in ensuring long-term success of STATCOM deployments.

⁵⁸ “Siemens energy strengthens German grid nodes with two STATCOM systems,” *Siemens Energy*, 2021. [Online]. Available: [Link](#).

5.6 Modeling Procedure

The implementation of STATCOMs into transmission systems necessitates several updates in system modeling, which directly impact system behavior under steady state, short circuit, and dynamic conditions.

5.6.1 Steady State Model

In steady state power flow modeling such as in PSS/E, STATCOMs are modeled as shunt FACTS devices. Key parameters, such as Shunt Max (MVA), define the reactive power limits, are marked on Figure 21⁵⁹.

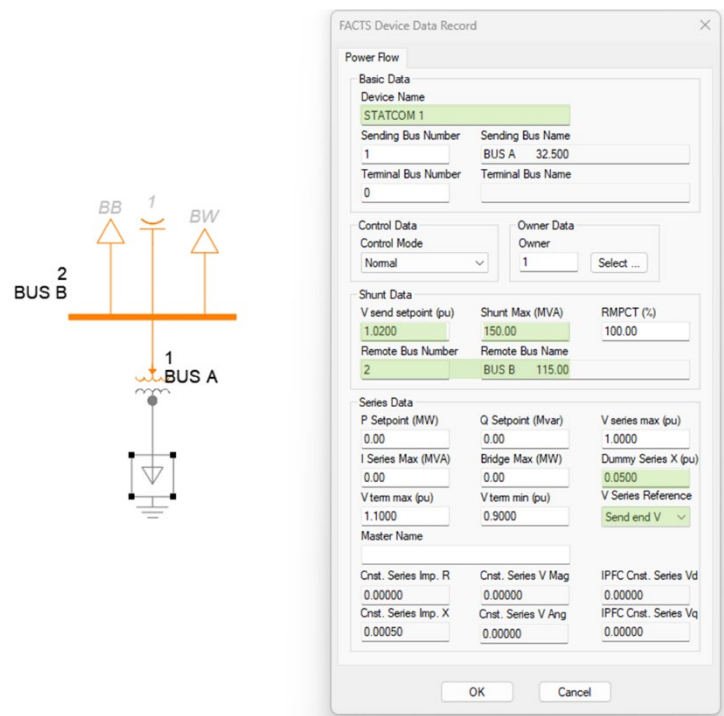


Figure 21: FACTS Parameters in PSS/E.

⁵⁹ “Modeling guideline for NYISO interconnection data,” NYISO, 2024. [Online]. Available: [Link](#).

5.6.2 Dynamic Model

In dynamic stability studies, dynamic models of STATCOMs are used to analyze system responses to time-domain disturbances, such as faults, switching events, or load fluctuations. In PSS/E, widely used dynamic models for STATCOMs are SVSMO3U2 in PSS/E v33 and SVSMO3T259 in PSS/E v34 and v35. The SVSMO3 model captures the fast-response characteristics of STATCOMs, including their control systems and interactions with other grid components. Figure 22 shows the FACTS tab in PSS/E representing SVSMO3T2 model.

Network data Dynamics data x								
	Device Name	Equipment Status	Model	Model Status	Type	Aux Model	Model Status	Type
▶	STATCOM 1	☒	SVSMO3T2	☐	Std	None	☐	

Figure 22. FACTS Tab Showing STATCOMs Dynamic Model.

5.6.3 Short Circuit Model

In short circuit studies, STATCOMs should be modeled as voltage controlled current source (VCCS) such that they do not inject real current into the grid⁵⁹.

6. Static VAR Compensators

6.1 Introduction

This chapter outlines a comprehensive framework for the implementation of Static Var Compensators (SVCs), which are shunt-connected devices within the FACTS family. SVCs regulate reactive power by adjusting shunt reactance, thereby enhancing voltage stability and contributing to more efficient and reliable grid operations. FACTS technologies, including SVCs, are increasingly critical in modern power systems as they offer dynamic control over key electrical parameters, enabling improved power quality, enhanced system stability, and better utilization of existing transmission infrastructure.

The deployment of SVCs has gained renewed importance in the context of growing renewable energy integration. As variable generation from wind and solar resources becomes more prevalent, maintaining grid stability requires advanced solutions for reactive power support. SVCs are particularly effective in this regard, providing fast and flexible compensation that helps mitigate voltage fluctuations and other operational issues associated with high levels of renewable penetration. The anticipated increase in renewable adoption, along with a stronger emphasis on power quality, is expected to drive significant growth in the SVC market over the next decade⁶⁰.

Despite being commercially available since the 1970s, the evolving nature of power system demands calls for updated and holistic approaches to SVC implementation. Traditional methods may not sufficiently address contemporary challenges, including the need for enhanced coordination across operational departments, integration with emerging technologies, and compliance with evolving regulatory standards. As such, this framework seeks to offer practical guidance that is both technically sound and aligned with modern grid requirements.

This chapter serves as a reference for SVC implementation. The subsequent sections investigate the technical configurations, operational principles, and mathematical models underpinning SVC functionality. The diverse applications and benefits of SVCs in addressing operational violations and improving system reliability are reviewed as well. Furthermore, key technical considerations for deployment are discussed, along with real-world case studies demonstrating their efficacy and the challenges associated with their adoption. Finally, the report concludes with modeling approaches essential for accurately representing SVCs in power systems studies, such as steady state, short circuit, and dynamic stability studies.

⁶⁰ S. Chaudhary, A. Gupta, “Static VAR compensator market size - by product, by application, analysis, share, growth forecast,” *Global Market Insights Inc.*, 2025. [Online]. Available: [Link](#).

6.2 Technology Background

The SVC provides reactive power compensation by regulating the shunt reactance. This section presents the key components and the configuration of the SVC as well as how the reactive power compensation capability is mathematically modeled.

6.2.1 SVC Configuration

The SVC has two popular configurations, with one of them consisting of a combination of a thyristor-switched capacitor (TSC) and thyristor-controlled reactor (TCR) connected in parallel. The TSC, as the name suggests, can be switched and only provides discrete and capacitive reactive power support. The controllability is enhanced by the TCR, which can be continuously regulated by controlling the partial conduction of the thyristor valve⁶¹. An alternative SVC configuration, shown in Figure 23 (a), is the combination of a TCR and a fixed capacitor (FC).

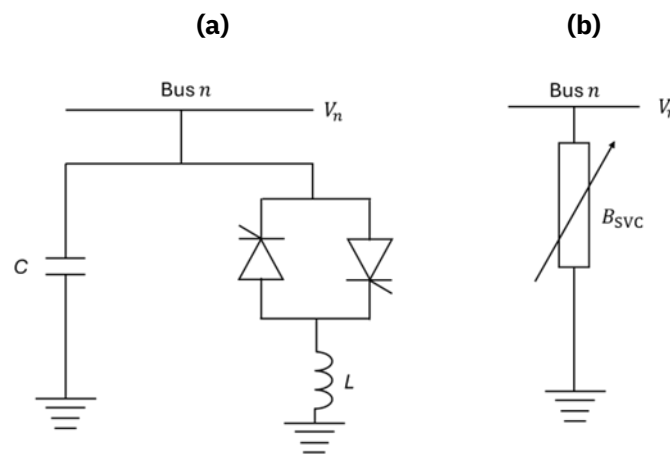


Figure 23: SVC Configuration (FC-TCR) and Modeling.

The TCR reactance is controlled by adjusting the firing angle. Therefore, the SVC can be modeled as a variable shunt susceptance, as shown in Figure 23(b). The SVC can provide inductive or capacitive reactive power to the grid by controlling the value of this shunt reactance.

In addition to the key components discussed in the previous subsection, SVC implementations can also involve other components as follows:

- **Coupling transformer:** It is a step-up transformer that connects SVC devices to the grid. The winding connection types have implications for power system protection which is discussed in detail later in Section 6.4. It is worth noting that SVCs can be directly connected to the power system without the need for a transformer as shown by some of industry examples⁶¹, where SVCs

⁶¹ "SVC Static Var compensator an insurance for improved grid system stability and reliability," ABB, Retrieved 2025. [Online]. Available: [Link](#).

are directly connected to 69 kV or to the 34.5 kV tertiary winding of an existing 345/138 kV autotransformer. This setup leads to various benefits including cost savings in hardware and other aspects, simplified SVC schemes, savings of site footprint, etc.

- **Harmonic filters:** They help mitigate the effect of harmonics generated by the TCR⁶². It is also worth noting that harmonics can be eliminated by tuning the FC with the FC-TCR configuration.

6.2.2 Operating Principal of SVC

As previously discussed, SVC has two operation regions, capacitive and inductive. In the capacitive region, the SVC's current is 90° leading to the voltage at Point of Common Coupling (PCC), and the SVC supplies capacitive reactive power to the power system. In the Inductive region, the SVC's current is 90° lagging to the voltage at PCC, and the SVC absorbs inductive reactive power from the power system.

The V-I characteristic of an SVC is shown in Figure 24. The nominal operation point of the SVC is at V_{ref} when $I_{SVC} = 0$. I_{Cmax} and I_{Lmax} represent the maximum capacitive and inductive currents at which SVC can regulate the current in a continuous manner, respectively. V_{max} and V_{min} represent the maximum and minimum reference voltages for continuous current control, respectively. If the voltage increased beyond V_{max} , the SVC will be kept at B_{min} until the voltage comes back to the controllable range. The same procedure is followed when the voltage decreased beyond V_{min} , the SVC will be kept at B_{max} , until the voltage comes back to the controllable range.

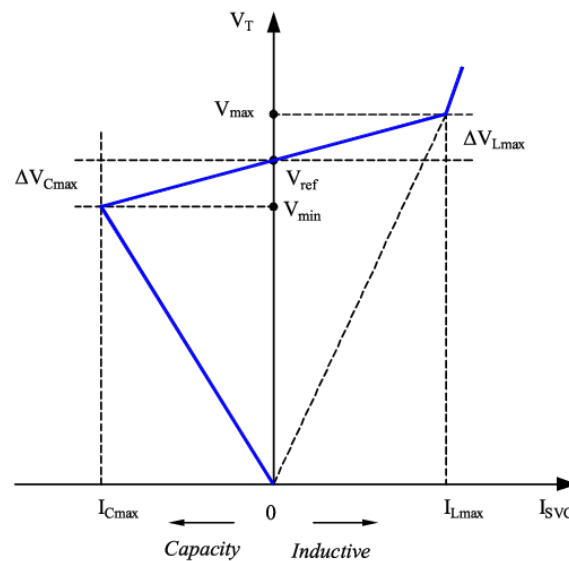


Figure 24: V-I Characteristic of an SVC

⁶² I. Damjanović, F. Tomašević, I. Pavić, B. Filipović-Grčić, A. Župan, "Harmonic performance analysis of static VAR compensator connected to the power transmission network," *Journal of Energy*, 2018.

Based on such modeling, SVC reactive power injection is presented as follows⁶³:

$$Q_{SVC} = -B_{SVC}V_n^2, \quad (1)$$

where B_{SVC} is the value of the controllable shunt susceptance which the SVC is modeled as. Q_{SVC} is the injected reactive power flow from the SVC to bus n which has the voltage level of V_n . Based on this formulation, Q_{SVC} can be either positive or negative, showing that the SVC can inject or absorb reactive power. The value of B_{SVC} is controlled by the firing angle of the TCR, typically varying from 90 to 180 degrees. The equation of B_{SVC} formulated as a function of the firing angle and the constraints on B_{SVC} are presented as follows⁶⁴, assuming the firing angle is constrained by the typical range:

$$B_{SVC} = \frac{X_C[2(\pi-\alpha)+\sin 2\alpha]-\pi X_L}{\pi X_L X_C}, \quad (2)$$

$$\frac{1}{X_C} - \frac{1}{X_L} \leq B_{SVC} \leq \frac{1}{X_C}. \quad (3)$$

In (2), α represents the TCR firing angle. X_L and X_C are the reactance of the inductor and the capacitor shown in Figure 23, respectively. As a result, the capacitive and inductive bounds of the SVC reactive power injection can be presented as follows:

$$-\frac{V_n^2}{X_C} \leq B_{SVC} \leq \frac{V_n^2}{X_L} - \frac{V_n^2}{X_C}. \quad (4)$$

6.3 Applications and Benefits

The main functionality of the SVC is to provide reactive power compensation which helps achieve a variety of benefits to power system operation. This section presents a summary of the key applications and benefits of SVC deployments in the power grid.

6.3.1 Reactive Power Compensation and Voltage Support

Voltage instability is an important issue in grid operation and can potentially lead to blackouts due to voltage collapse. One of the main causes of voltage instability is the limitation of reactive power transfer in transmission lines. In addition, the increasing usage of loads with no inertia leads to potential short-term voltage instability issues⁶⁵. Furthermore, the growing renewable energy resources penetration results in new challenges in voltage stability enhancement. Renewable energy resources generation outputs are naturally intermittent, uncontrollable, and unpredictable, which adds to the reactive power variations. Inverter-based resources are common for renewable energy resources integration provides no

⁶³ M. Haq, "Optimal power loss minimization using static VAR compensator (SVC)," M.Sc. thesis, Southern Illinois University at Edwardsville, 2024.

⁶⁴ M. Hassan, S. Cheng, A. Zakaria, "Steady-state modeling of SVC and TCSC for power flow analysis," in *Proc. of the International Multi Conference of Engineers and Computer Scientists*, 2009.

⁶⁵ Y. Lee, H. Song, "A reactive power compensation strategy for voltage stability challenges in the Korean power system with dynamic loads," *Sustainability*, 2019.

inertia to help maintain system stability⁶⁶. Additionally, the limited contribution to fault current from renewable energy resources can eventually lead to instability issues.

An effective solution to such voltage instability challenges is reactive power compensation which is one of the main benefits provided by the SVC. SVC devices provide continuous reactive power support as shown by the mathematical model in Section 6.2, as well as fast-response capabilities, a critical superiority compared to conventional reactive power compensation measures such as fixed shunt capacitors, to ensure adequate dynamic reactive power support in response to short-term voltage instability and avoid larger scale failures such as big blackouts⁶⁷.

6.3.2 Power Oscillation Damping

Power system oscillations deal with the analysis and control of low frequency oscillations in the 0.2-3 Hz range, which are characteristic of interconnected power systems. Small variations in system load excite the oscillations, which must be damped effectively to maintain secure and stable system operation. Inter-area oscillation is also a common issue in systems with a combination of synchronous and renewable generation⁶⁸. SVC devices help power oscillation damping and the effectiveness is shown in Figure 25.

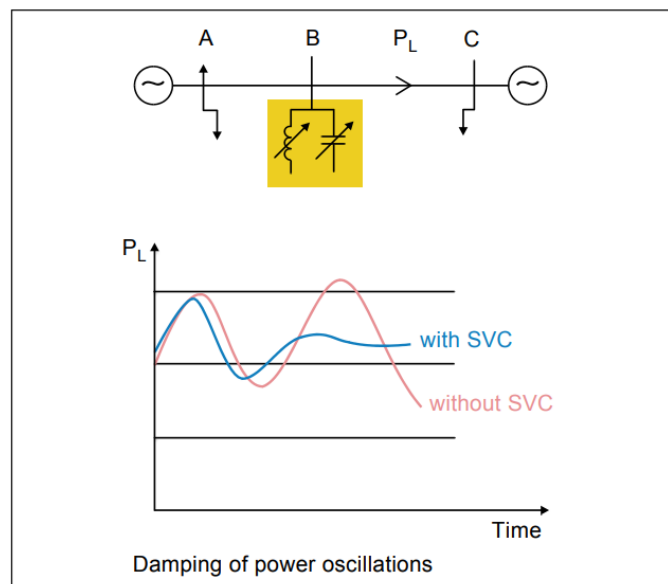


Figure 25: Power Oscillation Damping by the SVC.

⁶⁶ N. Hosseinzadeh, A. Aziz, A. Mahmud, A. Gargoom, M. Rabbani, "Voltage stability of power systems with renewable energy inverter-based generators: a review," *Electronics*, 2021.

⁶⁷ Y. Chi, Y. Xu, "Multi-stage coordinated dynamic VAR source placement for voltage stability enhancement of wind-energy power system," *IET Generation, Transmission & Distribution*, 2020.

⁶⁸ H. Roca, "Enhancing grid stability: power oscillation damping controls," *Green Power Monitor*, 2025.

6.3.3 Transfer Line Capacity Enhancement

The transfer capacity of a transmission line is constrained by the thermal limit, the voltage limit, and the stability limit⁶⁹. Thermal limits are the critical factor for the capacity of shorter transmission lines, whereas lines of moderate and very long lengths are constrained by voltage and stability limits, respectively. Reactive power compensation provided by the SVC can enhance the system stability, thus increasing the stability limits of transmission lines.

6.3.4 Summary of Grid Challenges Addressed by SVC

Table 21 summarizes the degree of impact SVCs have on addressing various grid reliability challenges.

Table 21: Degree of Impact of SVCs on Grid Reliability Challenge.

Thermal Violations	Voltage Violations	Stability Violations
Low	Notable	Notable

6.4 Technical and Operational Considerations

The successful deployment of SVCs in power systems depends not only on the technology itself but also on a holistic understanding of system requirements, coordination strategies, and operational integration. This section outlines key considerations related to site selection, sizing, control strategy, and system compatibility to ensure optimal performance and long-term reliability of SVC installations.

6.4.1 Technology Implementation Assessment

Implementing SVCs effectively within a transmission network involves addressing several key technical challenges related to their optimal placement and sizing. This process typically begins with detailed system studies, including power flow analysis, contingency analysis, and dynamic stability simulations, to identify voltage-weak areas where SVC support would provide the greatest benefit. Advanced optimization techniques can also be applied to determine ideal locations and ratings, guided by objective functions such as voltage deviation minimization and stability margin improvement. These technical assessments must be integrated with cost-benefit analyses that account for capital costs, operational savings, and the deferral of larger infrastructure upgrades.

6.4.2 Operation and Control Considerations

A critical consideration of SVC implementation is to ensure effective operation and control across various system conditions. Seamless integration with the Energy Management System (EMS) and Supervisory Control and Data Acquisition (SCADA) platforms is essential for enabling real-time monitoring, dispatch,

⁶⁹ S. Karimi, P. Musilek, A. Knight, “Dynamic thermal rating of transmission lines: a review,” *Renewable and Sustainable Energy Reviews*, 2018.

and automated control. Furthermore, coordination with other grid assets, including capacitor banks, synchronous condensers, and additional FACTS devices, is necessary to support complementary or hierarchical control strategies that optimize system stability and performance.

6.4.3 Protection and Reliability Considerations

Ensuring robust protection and high reliability is essential for effective SVC implementation. Comprehensive protection schemes must be integrated to safeguard the equipment against conditions such as overvoltage, overcurrent, DC link overvoltage, and system faults, with protective relays designed to detect and isolate disturbances promptly to prevent damage. Reliability can be further enhanced through the use of modular multi-level converters (MMC) and redundancy strategies that improve fault tolerance and minimize operational downtime. Additionally, maintaining high availability requires regular maintenance practices, including scheduled inspections, firmware updates, and proactive management of component life cycles to ensure sustained performance and system dependability.

6.4.4 Utility-Wide Impacts of SVC Deployment

The integration of SVCs affects key areas within a utility, including generation interconnection, transmission planning, system protection, operations, and engineering design. A comprehensive understanding of the role and impact of SVCs across utility departments is essential for effective deployment, operational reliability, and long-term system planning. This section outlines the specific considerations each department must account for when integrating SVCs into the power grid.

6.4.4.1 Generation Interconnection

SVCs can help ensure regulatory compliance for generation interconnection. Specifically, solar and wind power plants can benefit from SVCs in enhancing reactive power capabilities to meet interconnection requirements. Moreover, renewable energy resources are commonly located in remote areas with weak transmission connections, making it vital to have voltage support to ensure power deliverability⁷⁰. Federal Energy Regulatory Commission (FERC) Order No. 827 requires that new non-synchronous generation projects provide dynamic reactive power within the power factor range of 0.95 leading to 0.95 lagging at the high-side of the generator substation. An expected impact of such requirements is the installation of dynamic reactive power compensation device installations to enhance the power factor capability of non-synchronous generation.

6.4.4.2 Transmission Planning

As previously discussed, the SVC enhances the transfer capacity of transmission lines by providing stability improvements. The increased transmission capacity can reduce, defer, or eliminate the need for

⁷⁰ “Reactive power capability and interconnection requirements for PV and wind plants,” *ES/G*. [Online]. Available: [Link](#).

constructing new transmission lines, and such an effect can be achieved by an SVC providing 1-2 MW damping per MVAR⁷¹.

The SVC also involves a planning aspect which can be categorized under reactive power planning (RPP). The process of RPP is to determine the optimal allocation of different Var resources including generation, reserves, FACTS devices, etc⁷².

6.4.4.3 System Protection

The SVC impacts on the protection of both transmission lines and generators:

- **Transmission Line Protection:** SVC devices can impact the apparent impedance seen by the distance relay due to the injection of reactive power to provide voltage support when a fault occurs, thus creating problems for the protective relays and fault locators. Additionally, the behavior of the relay is affected by the winding types of the SVC coupling transformer⁷³. Note that the direct connection configuration of SVCs essentially eliminates the protection concerns related to transformer connection types. The proposed methods in the reference to mitigate the impact of the SVC are to bypass the zero-sequence component of the SVC and change the winding connection types of the coupling transformer to ones that have no zero-sequence current.
- **Generator Protection:** SVCs also affect the protection of synchronous generators against loss of excitation⁷⁴. It is shown by reference that SVC deployment causes delays in the protection against loss of excitation, potentially leading to the reduction of asset life especially under heavy loading conditions due to the synchronous generator operating for a longer period in undesirable conditions.

6.4.4.4 Operation and Control Systems

SVC deployments impact various aspects of system operation which can be summarized as follows:

- **Setpoint Adjustments:** Corresponding to load, generation, and power flow various in the system, SVC setpoints may need to be frequently adjusted to provide optimal reactive power support so that voltage stability can be ensured under different conditions. This is essentially important for post-contingency responses to prevent cascading failures and ensure power system security.
- **Relocation:** SVC deployments may need to be relocated to respond to significant system changes.

⁷¹ “Static var compensator solutions,” GE. [Online]. Available: [Link](#).

⁷² N. Karmakar and B. Bhattacharyya, “Optimal reactive power planning in power transmission system considering FACTS devices and implementing hybrid optimisation approach,” *IET Generation, Transmission & Distribution*, December 2020.

⁷³ A. Ghorbani, M. Khederzadeh, and B. Mozafari, “Impact of SVC on the protection of transmission lines,” *International Journal of Electrical Power & Energy Systems*, November 2012.

⁷⁴ F. C. Neves, A. L. M. Coelho, and I. P. Faria, “A testbed for assessing the impact of static var compensator on loss of excitation protection of synchronous generators,” *Electric Power Systems Research*, December 2021.

- **Maintenance and Upgrades:** The operation departments need to ensure SVC devices are functioning properly and provide necessary upgrades to their capacities.

6.4.4.5 Engineering and Design

The following aspects of SVC installation need to be paid attention to:

- **Device Size and Installation Space:** SVCs can involve devices that are bulky in size requiring large spaces for deployment at substations or mid-points of transmission lines. This factor may affect placement decisions of the SVC, making it important to ensure adequate space and, if needed, make necessary adjustments.
- **Pre-installation Studies:** Power system studies such as load flow analysis, flicker analysis, and harmonic analysis are necessary prior to SVC installations and the results need to be approved by the utility.

6.4.4.6 Summary of SVC impact on system operation and planning

Table 22 summarizes the impact of SVCs across various utility departments.

Table 22: Utility-Wide Impacts of SVCs Deployment.

Utility Function	Impact Level	Primary Benefits/Impacts of SVC Deployment
Generation Interconnection	High	Enhances reactive power capabilities of solar and wind plants to meet interconnection standards (e.g., FERC Order No. 827); supports voltage in weak transmission areas to ensure power deliverability.
Transmission Planning	High	Increases transmission capacity and system stability; may reduce or defer the need for new transmission lines; supports optimal reactive power planning (RPP).
System Protection	Medium	Can impact distance relay performance and fault location due to reactive power injection; requires careful transformer design and relay coordination; may delay generator protection during loss of excitation scenarios.
Operations and Control	Medium to High	Requires dynamic setpoint adjustments in response to system changes; may involve relocation of SVC units; maintenance and upgrades are essential to ensure reliable operation and post-contingency system security.
Engineering and Design	Medium	Large device footprint can influence siting decisions; pre-installation studies (e.g., load flow, harmonic analysis) are necessary for utility approval and to ensure system compatibility.

6.5 Best Practice

This section presents examples of SVC implementation in the current industry. The SVC, as one of the oldest FACTS technologies, has been widely deployed for various applications around the world.

6.5.1 Industry Examples

Notable industry examples of SVC deployments are presented as follows:

- **General Electric (GE):** GE's SVCs have deployed at various locations around the world, providing up to ± 300 MVAR of reactive power and operating at up to 500 kV. Notable examples of GE's SVC projects include implementations in the USA, Brazil, India, and Norway to provide reactive power support, reliability improvement, and voltage stability enhancement. An illustration of GE's SVC solution, which corresponds to the TSC-TCR configuration, was presented in Figure 24.
- **Nidec Conversion:** Nidec Conversion provides two types of SVC products. The "SILCOVAR T" operates at medium or high voltage levels and can provide up to 5 MVAR of reactive power support. The "SILCOVAR T" has a maximum rating of 250 MVAR while operating at 35 kV.
- **ABB:** ABB's SVC devices employ direct connection design and have been implemented in Western Texas to provide reactive power support to systems with higher wind power integration. ABB has also provided SVC solutions to help maintain system stability for TVA by ensuring sufficient reactive power support when conventional generators are retired in the utility's area to diversify the generation mix⁷⁵.

6.5.2 Lessons Learned

Key lessons learned from the industry examples are presented as follows:

- **Control Schemes:** Advanced control systems are essential to ensure the dynamic reactive power support capabilities of the SVC. For example, GE's SVC control system enables smooth integration in modeling tools to facilitate planning and transient analysis, see Figure 26.
- **Design and Configuration:** SVC devices can be implemented for various applications, and the solution needs to have suitable design and configuration. For example, certain SVC configurations can be more effective for lower/higher voltage levels. Additionally, as previously mentioned, the direct connection design of the SVC leads to a variety of benefits, which need to be considered.

⁷⁵ A. Larson, "ABB FACTS solution to help maintain grid stability for TVA as power generation mix changes," *POWER Magazine*. [Online]. Available: [Link](#).

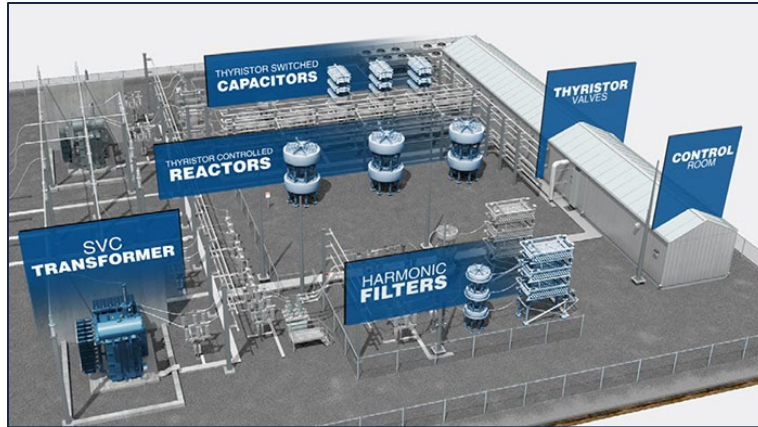


Figure 26: SVC from GE.

6.6 Challenges and Barriers

The key challenges and barriers faced by SVC deployment are summarized as follows:

- **Optimal Allocation:** this involves two aspects: placement and sizing. This is conducted using optimization in academic research, with some involving the usage of advanced solution techniques.
- **Incentives:** Proper regulatory measures or incentives are necessary to ensure that utilities and transmission owners are willing to have SVCs installed at their facilities.
- **Installation:** SVC installation can involve large expenses and require spaces to accommodate the size of the devices.
- **Power System Protection Concerns:** SVC devices can lead to delays in operation or loss of excitation protection and affect transmission line protection.
- **Proper Control Schemes:** Optimal control schemes are necessary to frequently adjust SVC setpoints to maintain bus voltage at a specified voltage level.

6.7 Modeling Procedure

The implementation of SVCs into transmission systems necessitates several updates in system modeling, which directly impact system behavior under steady state, short circuit, and dynamic conditions.

6.7.1 Steady State Model

The modeling of the SVC in power flow problems has been presented previously in Section 6.2. The SVC can be modeled as controllable in power flow calculations or as a fixed shunt impedance⁷⁶.

⁷⁶ “Static VAR Compensator (SVC),” Panda Power. [Online]. Available: [Link](#).

An SVC device can be modeled with either a generator or a switched shunt in PSS/E. If it is modeled with a switched shunt, then the reactive power output of the SVC can be discretely constrained by the blocks and steps within each block, as demonstrated in Figure 27. The MVAR value of the blocks can be either positive or negative, corresponding to the capability of the SVC to provide both inductive and capacitive reactive power compensation.

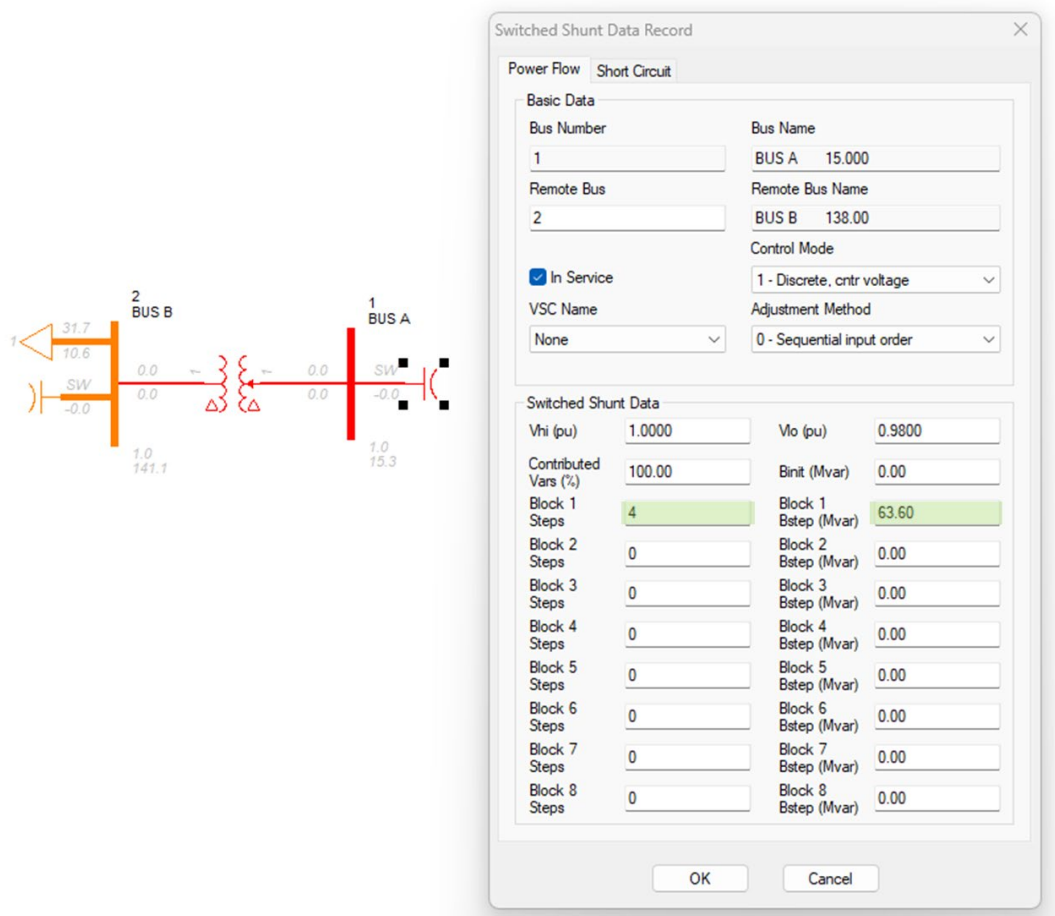
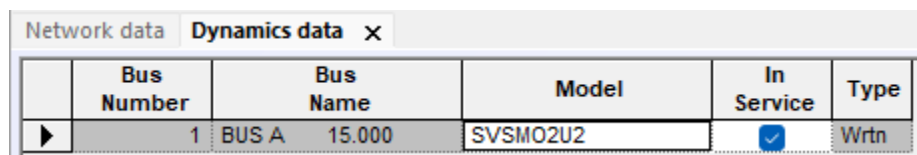


Figure 27: An SVC Device Modeled as a Switched Shunt in PSS/E and its Data Sheet.

6.7.2 Dynamic Model

In dynamic stability studies, various SVC dynamic models are included in the PSS/E model library. If the SVC device is modeled as a generator, then a family of the dynamic model CVSGN can be used to control it, such as CVSGN5. However, if it is modeled with as a switch shunt, then a family of SVSMO models can be used to continuously control SVC devices coupled with mechanically switched shunts (MSS), such as SVSMO2U2, see Figure 28. The following SVSMO models can be used to control both continuous and discrete SVC operations and outputs:

- SVSMO1 (Type 5): TCR-based SVC with coordinated shunt switching
- SVSMO2 (Type 7): TSC/TSR-based SVC with coordinated shunt switching



Network data		Dynamics data x			
	Bus Number	Bus Name	Model	In Service	Type
▶	1	BUS A 15.000	SVSMO2U2	☒	Wrtn

Figure 28: Switched Shunt Tab Showing SVCs Dynamic Model.

6.7.3 Short Circuit Model

In short circuit studies, SVCs should be modeled as voltage controlled current source (VCCS) such that they do not inject real current into the grid.

7. Synchronous Condensers

7.1 Introduction

A synchronous condenser (SC) is a synchronous machine that operates without a prime mover or a mechanical load and functions as a dynamic reactive power source to provide reactive power support and voltage regulation in power systems⁷⁷. Unlike conventional synchronous generators, which supply both real and reactive power, SCs primarily generate or absorb reactive power to enhance system stability and improve power quality. They draw a small amount of active power from the grid to compensate for internal losses. By adjusting the field excitation current, an SC can either inject or absorb reactive power, thereby regulating voltage at the point of connection. When over-excited, it operates with a leading power factor, supplying reactive power, whereas under-excitation results in a lagging power factor, absorbing reactive power from the grid.

SCs have been in use since the 1930s for voltage support and power factor correction. However, their adoption declined with the advent of solid-state power electronics solutions, such as SVCs and STATCOMs, due to the high initial investment and operational costs associated with SCs⁷⁷. Despite this, the increasing penetration of inverter-based resources (IBRs), such as wind and solar, has introduced new challenges for grid stability, including reduced system inertia and short circuit strength. Unlike SVCs and STATCOMs, SCs provide additional support by contributing to frequency stability and short circuit capacity, making them a crucial asset in modern power grids.

With the renewed demand for grid stability solutions, SC installations have surged globally. According to a research report published by Spherical Insights and Consulting, the global synchronous condenser market is projected to grow from \$556.3 billion to \$721.5 billion by 2033, reflecting the increasing reliance on SCs in addressing emerging grid challenges⁷⁸.

7.2 Technology Background

Traditionally, power systems have been dominated by synchronous machines, which inherently provide crucial grid services such as rotational inertia, fault current contribution, and voltage support. These machines play a fundamental role in maintaining grid stability by damping frequency fluctuations and ensuring robust system strength. However, with the ongoing transition toward renewable energy, such as solar and wind energy systems, the grid is increasingly relying on IBRs. While these resources offer efficiency and sustainability benefits, they inherently lack inertia, have limited short circuit capability, and

⁷⁷ P. Kundur, "Power system control and stability," *New York: McGraw*, 1994.

⁷⁸ "Global synchronous condenser market size to worth USD," *Spherical Insights and Consulting*, 2024. [Online]. Available: [Link](#).

provide constrained reactive power support. Consequently, this shift has led to increased grid instability, amplified vulnerability to disturbances, and challenges in maintaining voltage and frequency stability.

To mitigate these challenges, there has been a growing deployment of SCs in modern power systems. SCs help enhance voltage stability, improve power factor, support frequency regulation, and strengthen the overall resilience of the grid. By providing real-time dynamic reactive power support and short circuit capacity, SCs play a crucial role in reinforcing system reliability in grids with high penetration of IBRs.

This section serves as a reference for SC implementation. The subsequent sections investigate the technical configurations, operational principles, and mathematical models underpinning SC functionality. The diverse applications and benefits of SCs in addressing operational violations and improving system reliability are reviewed as well. Furthermore, key technical considerations for deployment are discussed, along with real-world case studies demonstrating their efficacy and the challenges associated with their adoption. Finally, the report concludes with modeling approaches essential for accurately representing SCs in power systems studies, such as steady state, short circuit, electromagnetic transients, and dynamic stability studies.

7.2.1 Components of an SC

An SC consists of several key components, each designed to ensure stable operation, efficient reactive power support, and enhanced grid stability. The primary components include the pony motor, rotor, stator, excitation system, protection and control system, cooling system, and an optional flywheel⁷⁹.

- **Pony motor:** A small auxiliary motor, typically rated between 200–300 kW, that facilitates the startup of the SC. It is controlled by a variable-speed drive that gradually accelerates the SC to synchronous speed over a few minutes. Once synchronization with the grid is achieved, the pony motor is de-energized and disengaged from operation, allowing the SC to run independently.
- **Rotor and stator:** The stator houses the AC armature windings, which generate a rotating magnetic field when connected to the power system. This magnetic field is essential for synchronous operation and reactive power exchange. The rotor is the rotating part of the SC and is magnetized using DC excitation to sustain the synchronous magnetic field. The interaction between the rotor's magnetic field and the stator's armature windings allows the SC to function as a reactive power source.
- **Excitation system:** The excitation system regulates the field excitation current, which determines the amount of reactive power injected or absorbed by the SC. The excitation system is categorized into two types: Brush-Type Excitation and Brushless Excitation.

⁷⁹ "Synchronous Condenser System," *Hitachi Energy*. [Online]. Available: [Link](#).

- **Cooling system:** As the SC operates continuously and handles significant electrical power, effective cooling is essential to dissipate heat and prevent thermal stress. The cooling system varies based on the size and rating of the SC:
 - Air Cooling: Used in small to medium-sized SCs.
 - Water Cooling: Provides enhanced cooling for medium to large SCs.
 - Hydrogen Cooling: Used in large-scale SCs for superior efficiency due to hydrogen's excellent thermal conductivity and low density, which reduces windage losses.
- **Protection and control system:** The protection and control system ensure safe operation and grid integration by continuously monitoring critical parameters such as voltage, current, frequency, and temperature. SCs are typically integrated into SCADA systems, enabling remote monitoring, automation, and fault detection for enhanced reliability and real-time operational adjustments.
- **Flywheel (Optional):** A flywheel can be incorporated into the SC system to increase inertia, enhancing frequency stability and short-term energy storage. By adding rotational mass, the flywheel helps mitigate rapid frequency fluctuations in grids with high renewable energy penetration. A notable real-world application is the Lister Drive Greener Grid Project in Liverpool, England, awarded to ABB in 2021. This project integrates a 67 MVAR SC with a 40-ton flywheel, increasing the inertial frequency response by 3.5 times. The enhanced inertia contribution improves frequency regulation and system resilience during grid disturbances⁸⁰.

Figure 29 illustrates the typical building blocks of an SC system. In practical applications, SCs are connected to the power grid through a step-up transformer and operate at synchronous speed to provide voltage and frequency support.

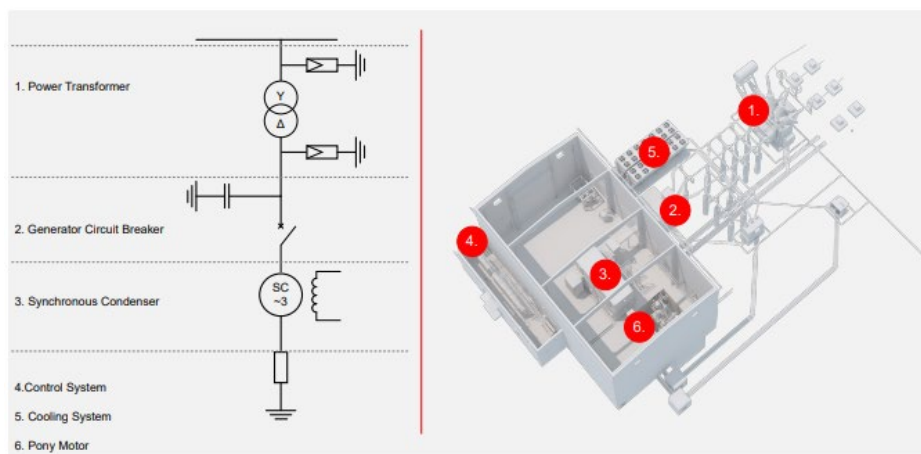


Figure 29: Typical Building Blocks of an SC System⁷⁹.

⁸⁰ C. Payerl, "Synchronous condensers rediscovered—a new way to strengthen grids," *Transmission & Distribution - Modern Power Systems*, 2021. [Online]. Available: [Link](#).

7.2.2 Working Principle of Synchronous Condensers

An SC operates similarly to a synchronous motor, but unlike a motor, it does not drive any mechanical load. Instead, it spins freely, providing dynamic reactive power compensation, voltage regulation, inertia support, and short circuit strength to the power grid. The operation of an SC can be categorized into the following key phases:

1. **Start-Up Phase:** At the initial stage, the SC is accelerated to synchronous speed using an auxiliary starting mechanism. There are two common methods for this process:
 - **Pony Motor Start-Up:** A pony motor (typically rated 200–300 kW) is mechanically coupled to the SC and gradually increases its speed until it synchronizes with the grid frequency. Once synchronization is achieved, the pony motor is disengaged.
 - **Variable Frequency Drive (VFD) Start-Up:** In some modern applications, a VFD is used to start the SC by gradually ramping up its speed electrically, offering a more controlled and efficient startup process.

Once the SC reaches synchronous speed, the excitation system is activated to establish the required magnetic field. At this point, the SC begins operating as a reactive power compensator.

2. **Steady-State Operation Mode:** During normal operation, the SC remains synchronized with the grid frequency and dynamically adjusts its reactive power output to support voltage stability. This process is controlled through the excitation system, which regulates the field current to modify the reactive power exchange:
 - **Over-Excited Mode (Reactive Power Generation):** When the grid requires additional reactive power, e.g., during voltage sags, the SC increases its excitation current, effectively supplying reactive power to boost voltage levels.
 - **Under-Excited Mode (Reactive Power Absorption):** When excessive reactive power is present in the system, e.g., during voltage swells, the SC decreases its excitation current, absorbing reactive power to stabilize voltage.

This rapid response capability enables SCs to correct voltage fluctuations within milliseconds, making them highly effective in mitigating grid disturbances.

3. **Inertia and Short Circuit Support Mode During Grid Disturbances:** In addition to reactive power regulation, SCs contribute to grid stability through two critical support mechanisms:
 - **Inertial Response to Frequency Changes:** When a sudden generation-load imbalance occurs in the grid, frequency deviations can lead to instability. The rotating mass of the SC inherently provides inertial response, which slows down the rate of change of frequency (RoCoF) and helps maintain system stability during transient disturbances. This feature is especially valuable in modern grids with high IBR penetration, where system inertia is significantly reduced.

-
- **Short Circuit Support During Fault Conditions:** In the event of a grid fault, e.g., a short circuit, the SC responds with a high inrush of fault current due to its sub-transient reactance characteristics. Similar to conventional synchronous generators, SCs can supply fault currents 5 to 7 times their rated current, significantly improving the system's short circuit capacity and enhancing protective relay coordination.

7.3 Applications and Benefits

With the increasing penetration of IBRs in modern power systems grid, SCs are being widely deployed to enhance grid stability and reliability. The following sections discuss key applications and benefits of SCs in power systems.

7.3.1 Voltage Stability and Regulation

SCs play a crucial role in voltage stability and dynamic voltage regulation by absorbing or injecting reactive power based on real-time grid conditions. Unlike fixed capacitor banks, SCs provide continuous and dynamic reactive power compensation, allowing for more effective voltage stabilization, particularly in weak grid conditions with high renewable energy penetration. Here are the key functions of SCs in voltage regulation:

- **Dynamic Voltage Support:** By adjusting field excitation, SCs can respond instantly to voltage fluctuations, mitigating voltage sags, swells, and flicker that can negatively impact industrial processes and power quality.
- **Reactive Power Control:** Unlike passive compensation devices, SCs continuously adjust reactive power output, ensuring optimal voltage regulation across the transmission network.
- **Weak Grid Stabilization:** SCs improve voltage control in regions with high renewable energy penetration, where grid strength is relatively low due to the limited fault current contribution from IBRs.

Real-World Examples:

- **Vineyard Wind Project:** To support the integration of the Vineyard offshore wind farm, two SC systems were installed with a rated condenser output of +171/-133 MVar, ensuring voltage stability and reactive power control. The project was supplied by Andritz⁸¹.
- **Siemens Energy SCs for Southern California:** Seven SCs were installed to support power transfer from the Intermountain Power Project to California. The HVDC line from Delta to Adelanto could not operate at full capacity due to the lack of voltage support after the retirement of the San

⁸¹ "Synchronous condenser," Andritz. [Online]. Available: [Link](#).

Onofre Nuclear Generating Station (SONGS), highlighting the critical role of SCs in maintaining voltage stability⁸².

7.3.2 Short Circuit Power Contribution and Fault Ride-Through Capability

One of the key limitations of IBRs is their low short circuit current contribution. Unlike synchronous machines, which provide substantial fault currents, power electronic-based inverters supply limited fault currents, making it difficult for protective relays to detect and isolate faults efficiently. Here are key benefits of SCs in fault support:

- **Enhanced Fault Ride-Through Capability:** SCs contribute fault currents up to 5–7 times their rated current, significantly improving the fault detection and isolation process in protection systems.
- **Improved Grid Resilience:** By increasing the short circuit strength of the system, SCs enhance protective relay coordination and prevent nuisance tripping of transmission lines and substations.
- **Restoration of Grid Strength:** In grids with a high share of renewables, SCs improve system robustness by supplying fault currents like conventional generators.

Real-World Examples:

- **Darlington Point Solar Farm (Australia):** Two ABB SCs were installed to increase short circuit strength, improving fault ride-through capability in a system with high solar penetration⁸⁰.
- **Ouyen SC for Kiamal Solar Farm (Australia):** A 221-ton SC rated at 190 MVar was installed near Ouyen, Northwest Victoria, to protect and stabilize the grid connected to the 256 MW Kiamal Solar Farm⁸³.

7.3.3 Inertia Support and System Strength

As conventional synchronous generators are phased out, power systems with high IBR penetration are experiencing reduced inertia and weakened grid strength. SCs address these challenges by providing rotational inertia and improving transient stability. Here are key contributions of SCs to system strength:

- **Inertial Response:** SCs act as virtual inertia sources, reducing RoCoF and preventing system-wide frequency instability.
- **Transient Stability Enhancement:** SCs improve grid stability by providing synchronized torque response during disturbances, reducing frequency deviations and voltage dips.

⁸² “Synchronous condensers: Key to grid stability in North America,” *Siemens Energy*. [Online]. Available: [Link](#).

⁸³ “Largest synchronous condenser in Australia,” *OMEXOM*. [Online]. Available: [Link](#).

Real-World Examples:

- **ERCOT Study on West Texas Grid Reliability:** A study conducted by ERCOT recommended the installation of SCs at six strategic locations to improve system inertia, voltage stability, and short circuit strength. As part of this initiative, two SCs are being installed at an LCRA TSC substation in Pecos County, reinforcing grid resilience and supporting voltage regulation⁸⁴.

7.3.4 Summary of Grid Challenges Addressed by SCs

Table 23 summarizes the degree of impact SCs have on addressing various grid reliability challenges:

Table 23: Degree of Impact of SCs on Grid Reliability Challenge.

Thermal Violations	Voltage Violations	Stability Violations
Minor	Notable	Notable

7.4 Technical and Operational Considerations

With the increasing penetration of IBRs in the grid, the SC technology is playing a critical role in the reliable integration of these resources. However, several key factors must be considered before deploying SCs, including optimal placement and the choice between retrofitting existing infrastructure or constructing new units. This section outlines such key factors to ensure optimal performance and long-term reliability of SCs installations.

7.4.1 Optimal Location of the Synchronous Condensers

The effectiveness of SCs depends significantly on their strategic placement within the power grid. These devices should be installed in locations that maximize voltage stability, provide inertia support, and enhance fault ride-through capability.

- **Weak Grid Areas:** SCs are best suited for areas where grid strength is low and where renewables dominate generation. These areas often suffer from low inertia and poor short circuit strength, making SCs an ideal solution.
- **High Renewable Penetration Regions:** SCs should be deployed near wind and solar farms to mitigate voltage fluctuations and improve reactive power balance.
- **Interconnection Points:** Placing SCs at major transmission substations ensures system-wide stability and prevents cascading failures during disturbances.

Based on the assessment performed by ERCOT, six optimal locations were identified, as shown in Figure 30, for deploying SCs to significantly improve the reliability of the West Texas system, make system more

⁸⁴ “New transmission project to boost reliability in West Texas,” LCRA. [Online]. Available: [Link](#).

resilient to grid disturbances and address challenges during real-time operations⁸⁵. This assessment estimated an average increment of 11% in the system strength within the West Texas region with the recommended changes.

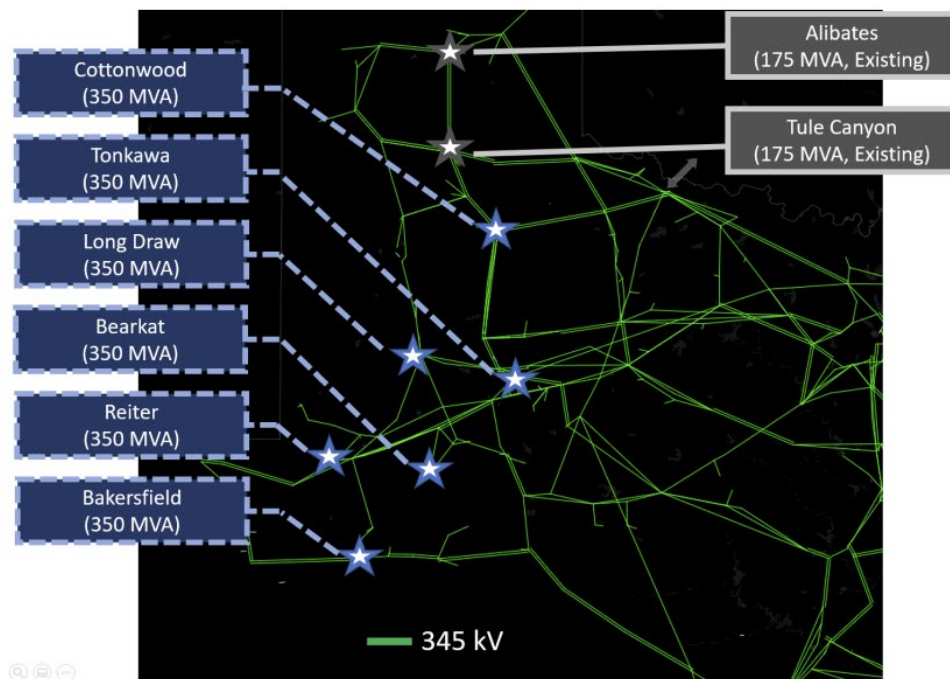


Figure 30: Recommended Locations for the Placement of SCs in West Texas⁸⁵.

7.4.2 Retrofitting vs. New-Build Considerations

As coal and fossil fuel-based synchronous generators are retired, many utilities are exploring the option of retrofitting these existing assets into SCs as a cost-effective alternative to new installations. While retrofitting can offer significant financial and logistical advantages, it also introduces technical and operational challenges that must be carefully assessed before making a final decision.

Advantages of Retrofitting Existing Generators:

- **Reduced Capital Expenditure:** Retrofitting can lower initial investment costs by 40–50% compared to installing a new SC.
- **Utilization of Existing Infrastructure:** Foundations, cooling systems, and other auxiliary components from the retired generator can often be repurposed, minimizing additional construction requirements.
- **Faster Deployment:** Retrofitting typically has a shorter implementation timeline than a ground-up installation, accelerating the availability of reactive power support and inertia to the grid.

⁸⁵ “ERCOT assessment of synchronous condensers to strengthen the west Texas system,” *ERCOT*, version 1.0, June 2023. [Online]. Available: [Link](#).

Challenges of Retrofitting:

- **Aging Equipment:** Older generators may require extensive refurbishment, including upgrades to rotors, excitation systems, and other critical components, potentially offsetting cost savings.
- **Lower Efficiency:** Retrofitted SCs may not perform as efficiently as newly designed units, which are optimized for inertia and reactive power support.
- **Limited Operational Lifespan:** Retrofitted units may have a reduced lifespan due to wear and fatigue from previous generator operation.

Real-World Examples:

An example of retrofitting retired generators into SCs includes the two retired generators at AES Huntington Beach plant which were converted to SCs to provide voltage support after the retirement of the SONGS⁸⁶.

Conversely, the Phoenix Project in the UK opted for new SC installations over retrofitting. A detailed assessment determined that newly built SCs offered superior reliability and lower long-term operational costs. Additionally, the project introduced ABB's Hybrid-SC technology, which integrates STATCOMs for rapid voltage response with SCs' inherent inertia and fault current contribution, providing a more robust grid support solution⁸⁷.

7.4.3 Other Considerations

In addition to location and retrofitting assessments, several other technical and operational factors must be considered to ensure the effective deployment of SCs within the power grid.

- **Transmission Network Capacity:** SCs consume reactive power during voltage swells, which can place additional stress on an already overloaded transmission network. Therefore, a comprehensive SIS must be conducted to assess whether the existing network can accommodate SCs without adversely affecting grid stability.
- **Co-ordination with Other Grid Devices:** SCs interact with various dynamic grid devices, including STATCOMs, HVDC systems, and IBRs. In some cases, these interactions may lead to control-based voltage oscillations, reactive power conflicts, or unintended stability issues. A detailed compatibility assessment should be conducted when SCs are deployed near other active grid components to mitigate potential reliability concerns.
- **Sub-Synchronous Oscillation (SSO) Assessment:** When SCs are installed near series-compensated transmission lines, they can contribute to SSO, which may lead to instability or

⁸⁶ "AES Uses synchronous condensers for grid balancing," *Power Magazine*. [Online]. Available: [Link](#).

⁸⁷ "Hitachi ABB power grids' innovative technology set to contribute to the UK's carbon-neutral future," *Hitachi*. [Online]. Available: [Link](#).

damage to grid infrastructure. An SSO study is essential before SC deployment in such locations to ensure reliable long-term system operation.

- **Integration With Other Technologies:** SCs can be effectively integrated with other grid support technologies to enhance system performance.
 - **SCs and Flywheels:** The combination of SCs with flywheel energy storage can provide additional inertial support, improving frequency stability.
 - **SCs and STATCOMs:** A hybrid approach that combines SCs with STATCOMs allows for both fast-response voltage support and inertia enhancement, offering a more comprehensive grid stability solution.

Considering these factors during planning and implementation will ensure that SC deployments maximize grid reliability, operational efficiency, and resilience against disturbances.

7.4.4 Utility-Wide Impacts of Synchronous Condenser Deployment

The integration of SCs affects key areas within a utility, including generation interconnection, transmission planning, system protection, operations, and engineering design. A comprehensive understanding of the role and impact of SCs across utility departments is essential for effective deployment, operational reliability, and long-term system planning. This section outlines the specific considerations each department must account for when integrating SCs into the power grid.

7.4.4.1 Generation Interconnection

SCs significantly impact the generation interconnection process, particularly in areas with high penetration of IBRs, such as wind and solar, and HVDC systems. The impact will be notable in terms of reactive power support, system strength, short circuit capacity, inertia and frequency stability.

7.4.4.2 Transmission Planning

SCs are a critical component of modern transmission planning strategies, particularly in networks with high penetration of IBRs, where voltage stability and reactive power balancing are key concerns, weak grid conditions, where system strength is insufficient to support reliable operations, and HVDC interconnections, where additional support is needed for stability and power flow control.

While SCs provide several operational advantages, including reactive power support, enhanced system strength, improved short circuit capacity, and inertia support as discussed in previous sections, their integration adds complexity to transmission planning studies. The planning process must account for:

- **Updated contingency lists:** SC failures should be considered in NERC Categories P1 and P3 contingencies to assess their impact on system reliability and stability.
- **Permissible system adjustments:** SCs may be included as allowed system adjustments for NERC Categories P3 and P6 contingencies, cascading events, and post-transient analyses.
- **Reliability compliance considerations:** SCs must adhere to various NERC reliability standards, including MOD-025, MOD-026, MOD-032, PRC-019, and PRC-024.

Given these considerations, transmission planners must incorporate detailed dynamic and short circuit studies to ensure that SC deployment aligns with broader grid planning objectives while maintaining system reliability.

7.4.4.3 System Protection

The introduction of SCs into the grid has significant implications for system protection schemes, particularly in weak-grid areas where fault current levels are already low. Since SCs contribute to short circuit capacity, their deployment can improve protection system performance by:

- **Enhancing fault current levels**, enabling more effective detection and isolation of faults by protective relays.
- **Improving protection coordination**, ensuring selectivity and sensitivity of relays to prevent mis-operations.
- **Reducing the risk of inadvertent tripping**, particularly in low short circuit strength regions where protection devices may struggle to differentiate between normal and fault conditions.

However, integrating SCs into the grid also requires adjustments to relay settings and coordination studies to account for changes in short circuit levels. Transmission utilities must ensure that:

- Relays are recalibrated to reflect the new system condition.
- Protection coordination studies are updated to account for SC fault contributions under various operating scenarios.
- Potential interactions between SCs and IBRs are assessed to avoid unintended system oscillations that could lead to protection mis-operations.

Ensuring a well-coordinated protection scheme is essential to fully leveraging SC benefits while maintaining a secure and resilient power system.

7.4.4.4 Operation and Control Systems

From a real-time operations perspective, SCs provide utilities with greater flexibility and enhanced stability during normal and contingency conditions. Their primary operational benefits include:

- **Voltage and frequency support:** SCs help stabilize system voltage by providing dynamic reactive power compensation, particularly during periods of fluctuating demand or high IBR generation.
- **Enhanced system inertia:** By contributing to system inertia, SCs mitigate RoCoF following sudden disturbances.
- **Improved grid resilience:** During system disturbances such as transmission faults, generator trips, or large power swings across HVDC links, SCs provide critical dynamic support that enhances grid stability and reduces restoration times.

Operational challenges associated with SC deployment include:

- Dynamic coordination with other reactive power compensation devices, e.g., STATCOMs, SVCs, capacitor banks, requiring advanced control strategies to prevent reactive power conflicts.
- Incorporation into real-time dispatch and voltage control strategies, ensuring that SCs are optimally utilized without introducing operational constraints.
- Potential concerns with maintenance schedules, as SCs are rotating machines that require periodic inspections, cooling system management, and excitation system monitoring.

Grid operators must have appropriate visibility and control mechanisms to integrate SCs into EMS and SCADA platforms for effective real-time operation and contingency response.

7.4.4.5 Engineering and Design

The deployment of SCs introduces significant engineering and design considerations, impacting substation infrastructure, grid integration, and long-term asset management. Key aspects that must be addressed include:

- Substation Layout and Space Requirements:
 - SCs require dedicated substation space for installation, often necessitating modifications to existing substations or the construction of new facilities.
 - Cooling and ventilation systems must be incorporated to manage heat dissipation from the rotating machine.
- Electrical Integration and Control Systems:
 - SCs must be seamlessly integrated into the existing grid control architecture, requiring modifications to relay protection settings, excitation systems, and SCADA interfaces.
 - Coordination with other voltage regulation devices, such as STATCOMs and SVCs, is crucial to maintain stability under varying grid conditions.
- Grid Optimization and Long-Term Planning:
 - SCs help reduce the need for additional transmission infrastructure by enhancing system strength and optimizing power flow across existing lines.
 - Proper deployment of SCs can extend asset lifespan by alleviating stress on transmission equipment, reducing voltage instability risks, and mitigating power quality issues.

Ensuring comprehensive engineering assessments, robust system modeling, and coordinated integration plans is essential to maximizing the benefits of SC deployment while minimizing infrastructure costs and operational risks.

7.4.5 Summary of SC Impact on System Operation and Planning

Table 24 summarizes the impact of SCs across various utility departments.

Table 24: Utility-Wide Impacts of SCs Deployment.

Utility Function	Impact Level	Primary Benefits/Impacts of SC Deployment
Generation Interconnection	High	Enhances reactive power support, system strength, short circuit capacity, and inertia, enabling stable integration of IBRs like wind, solar, and HVDC systems.
Transmission Planning	High	Improves voltage stability, reactive power balance, and system strength; supports contingency analysis, compliance with reliability standards, and dynamic/short circuit studies.
System Protection	High	Increases fault current levels, improves relay coordination and selectivity, and enhances protection performance in weak-grid areas, requires updated relay settings and coordination.
Operations and Control	High	Provides dynamic voltage and frequency support, boosts system inertia and grid resilience, but requires advanced coordination with other devices and integration into EMS/SCADA.
Engineering and Design	High	Requires substation space and cooling, affects control and protection system integration, and supports long-term grid optimization and reduced stress on transmission infrastructure.

7.5 Best Practice

This section presents real-world examples of SC technology implementation, and the key lessons learned from these applications. These case studies highlight how SCs enhance grid stability, support renewable energy integration, and improve system resilience in various operational contexts.

7.5.1 Grid Stability After Generator Retirements

The retirement of large synchronous generators significantly impacts grid reliability by reducing system inertia, short circuit capacity, and voltage support. SCs can effectively mitigate these losses, restoring critical grid functions and ensuring stable operations. While devices such as STATCOMs and SVCs provide voltage regulation, SCs uniquely offer additional inertia and short circuit support, making them the preferred choice for systems requiring comprehensive stability enhancements.

- **Southern California, USA:** When the San Onofre nuclear power plant shut down, the Southern California grid lost a crucial source of voltage support. To address this issue, CAISO collaborated with AES and Siemens Energy to repurpose two retired units at the Huntington Beach station into

SCs. This conversion leveraged much of the existing infrastructure, incorporating essential upgrades such as pony motors, thrust bearings, variable frequency drives (VFDs), and digital control system (DCS) panels. The project was completed within an accelerated timeline, achieving full operation by June 2013. Currently, seven Siemens Energy SCs provide voltage and inertia support in the region, stabilizing the grid and maintaining operational reliability.

- **Bavaria, Germany:** Following the 2018 closure of the 1.34 GW Gundremmingen nuclear power plant, grid stability in Oberottmarshausen was compromised due to reduced inertia and reactive power compensation. To address these issues, an SC was installed, delivering ± 340 MVAR of reactive power support. This solution optimized efficiency and prolonged equipment lifespan while ensuring stable voltage regulation under varying grid conditions⁸⁸.
- **Hesse, Germany:** In response to Germany's nuclear phase-out policy after the Fukushima incident, a unit from the 2.5 GW Biblis nuclear power plant was repurposed into a rotating SC in 2013. This upgrade included the installation of a 14 MW startup converter, integration with 18.3 MVA and 17 MVA transformers, and a 30 kV gas-insulated switchgear connection. The converted condenser now provides reactive power support ranging from -400 MVAR to +900 MVAR, significantly enhancing voltage stability for the grid operator Amprion⁸⁸.

These implementations demonstrate the effectiveness of SCs in maintaining grid stability following generator retirements, providing a roadmap for future projects facing similar challenges.

7.5.2 Reliably Interconnecting IBRs at Remote Locations

As the penetration of IBRs such as wind and solar farms increases, grid stability challenges become more pronounced, particularly in remote areas with weak grid conditions. SCs provide a robust solution by compensating for reduced inertia, enhancing voltage stability, and improving short circuit strength, enabling reliable interconnection of renewable energy sources.

- **New Mexico, USA:** In 2018, the Public Service Company of New Mexico installed a Siemens Energy SC at its Blackwater station in Clovis to support the transmission of 200 MW of wind power over a 216-mile line to Albuquerque. The SC enhanced voltage stability and short circuit strength, preventing operational issues for utilities managing renewable integration⁸⁹.
- **West Texas, USA:** As ERCOT continues to integrate IBRs, grid challenges such as weak network conditions and reduced voltage support have emerged. To address these issues, ERCOT is installing two SCs at an LCRA TSC station in Pecos County, reinforcing grid reliability and ensuring stable renewable energy integration.
- **Italy:** In 2020, Terna installed two SCs equipped with flywheels at the Brindisi station to bolster grid stability. Each unit provides ± 250 MVAR of reactive power and 1750 MW of inertia, totaling

⁸⁸ "Synchronous condensers," *ENTSO-E*, March 2025. [Online]. Available: [Link](#).

⁸⁹ "Synchronous condensers: key to grid stability in north America," *Siemens Energy*. [Online]. Available: [Link](#).

500 MVAR and 3500 MW for the entire system. This infrastructure supports renewable energy integration while mitigating frequency fluctuations.

- **Denmark:** In 2015, Denmark deployed SCs at the Bjæverskov, Fraugde and Herslev stations to support its high wind energy share. Each unit provides over 900 MVA of short circuit power and ± 215 MVAR (Bjæverskov) or ± 150 MVAR (Fraugde & Herslev) of reactive power. These SCs ensure voltage stability and enhance system resilience, achieving 98% operational availability.

These cases highlight SCs' effectiveness in enabling reliable IBR integration in remote regions, ensuring sustainable grid operations.

7.5.3 Providing support to the HVDC transmission system

SCs enhance HVDC transmission system performance by addressing low short circuit strength, voltage stability, and inertia limitations. Installing SCs near HVDC converter stations significantly improves overall system reliability.

- **Sardinia, Italy:** In 2014, two 250 MVar SCs were installed in Codrongianos to stabilize the Sardinian grid and optimize its HVDC interconnections. These units feature an innovative round rotor design, two-pole structure for reduced weight, and air-to-water cooling. They also incorporate a fast static starting system (<15 minutes), adiabatic cooling, and remote unmanned operation. With a 200% overload capacity (for 10 seconds) and total losses of only 1.15%, the project ensures safer and more efficient utilization of Sardinia's HVDC links.

This example underscores the critical role of SCs in enhancing HVDC grid performance, particularly for islands and long-distance power transfer applications.

7.5.4 Improving Power Quality for Industrial Applications

Industrial operations with significant power demands require stable voltage levels and power quality to ensure efficient and uninterrupted processes. SCs contribute to industrial power systems by improving power factor, mitigating harmonics, and providing dynamic voltage support, particularly for operations with high inductive loads.

- **Peru:** In 2013, ABB commissioned two SCs and harmonic filters for Xstrata Copper's Antapaccay project in southern Peru. The project, located in a remote region, depended on a long power transmission line. The SCs provided precise and dynamic power factor correction, enhancing grid stability and ensuring reliable mining operations. Additionally, harmonic filters helped reduce disturbances, optimizing energy efficiency and equipment lifespan⁹⁰.

⁹⁰ "ABB successfully commissions synchronous condensers at Antapaccay copper mine," *Mining*, September 2013. [Online]. Available: [Link](#).

This case demonstrates how SCs effectively mitigate power quality issues in industrial applications, especially in remote locations where transmission constraints exist.

7.6 Challenges and Barriers

Despite the significant benefits of SCs in enhancing grid stability, several challenges continue to limit its widespread adoption. These challenges include high capital and operational costs, space and maintenance requirements, efficiency concerns, integration complexities, and regulatory hurdles. Addressing these barriers is essential to maximizing the effectiveness of SC technology and ensuring its viability as a long-term grid stability solution.

7.6.1 High Capital and Operational Costs

One of the primary challenges associated with SC deployment is the high initial capital investment and ongoing operational costs.

- A complete SC system, including cooling, excitation, and protection systems, can cost hundreds of thousands of dollars per MVAR. This makes it a significant upfront investment compared to alternative grid support technologies such as STATCOMs and SVCs⁹¹.
- In addition to installation costs, SCs require substantial operational and maintenance expenditures. The presence of rotating components contributes to higher maintenance costs, typically ranging between \$0.4 per kVAR to \$0.8 per kVAR per year. Scheduled inspections, component replacements, and lubrication requirements add to the total cost of ownership.

Due to these high costs, utilities must conduct thorough cost-benefit analyses to determine whether SC deployment is economically justified in comparison to other solutions that provide reactive power and voltage support.

7.6.2 Space and Maintenance Requirements

SCs require a significant amount of physical space compared to power electronic-based solutions such as STATCOMs and SVCs.

- The size and weight of SCs make them difficult to install in locations where space is constrained, such as dense urban areas or existing substations with limited expansion possibilities.
- Unlike FACTS devices, which are compact and modular, SCs consist of large rotating machines that necessitate additional infrastructure, such as cooling systems, control panels, and robust foundations to support their weight and operational dynamics.

⁹¹ “Synchronous condenser market by cooling type,” *Markets and Markets*. [Online]. Available: [Link](#).

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- The mechanical nature of SCs also introduces additional maintenance requirements. Periodic inspections, alignment checks, and potential overhauls increase operational downtime and require skilled personnel for upkeep.

7.6.3 Efficiency and Energy Losses

Another limitation of SCs is their relatively lower efficiency and higher energy losses compared to alternative reactive power compensation technologies.

- SCs typically exhibit energy losses of approximately 1–3%, whereas SVCs and STATCOMs operate with losses ranging from 0.1% to 1%⁹².
- The continuous energy consumption of SCs, even when they are not actively compensating for reactive power fluctuations, further contributes to their overall inefficiency.
- These losses may be more evident in systems with frequent operational fluctuations, requiring utilities to carefully assess the long-term energy implications of SC deployment.

7.6.4 Complexity of Grid Integration and Control

Integrating SCs into modern power systems presents several technical challenges, particularly in networks with high penetration of IBRs.

- SCs must be carefully coordinated with other grid devices, including STATCOMs, SVCs, HVDC links, and energy storage systems, to prevent reactive power conflicts and voltage oscillations.
- The deployment of SCs introduces additional considerations in transmission planning, including contingency analysis, fault ride-through capability assessments, and adjustments to grid protection schemes.
- Due to their mechanical inertia, SCs respond more slowly to system disturbances compared to fast-acting power electronic devices, which may necessitate additional measures to enhance system flexibility.

7.6.5 Regulatory and Market Barriers

Regulatory and market challenges also play a role in limiting the adoption of SC technology.

- In many energy markets, SCs do not generate revenue in the same way as traditional generators, making it difficult for utilities to justify their investment purely from a financial standpoint.
- Regulatory frameworks often prioritize cost-effective solutions for voltage support and system stability, which may favor lower-cost options such as STATCOMs and SVCs over SCs.
- The classification of SCs within transmission planning frameworks can also be ambiguous, making it challenging to secure funding for their deployment.

⁹² J. Gentle, S. M. Alam, M. Sun, Z. Priest, C. Postma, and K. Tetz, “Shunt- connected FACTS and synchronous condensers,” *Idaho National Laboratory*, November 2024.

7.6.6 Limited Industry Experience and Skilled Workforce

Despite their historical use, SCs are not as widely deployed as other grid stabilization technologies, leading to challenges in expertise and workforce availability.

- Many utilities and transmission operators may lack the necessary technical knowledge and experience to integrate and operate SCs efficiently.
- The specialized skills required for maintenance and troubleshooting of SCs further exacerbate this challenge, necessitating additional training programs and workforce development initiatives.

7.7 Modeling Procedure

This section outlines the modeling methodologies for SCs in different types of power system studies, including steady state analysis, dynamic stability analysis, and electromagnetic transient (EMT) studies.

7.7.1 Steady State Model

In steady state studies, SCs are typically represented as controllable reactive power sources with their active power set to zero. In some cases, a small negative value may be assigned to the active power to account for internal losses, reflecting the minimal real power drawn from the grid. SCs operate in one of two control modes:

- **Voltage Control Mode:** Regulates and maintains a set terminal voltage, ensuring local voltage stability.
- **Reactive Power Control Mode:** Operates at a specific reactive power output (Q setpoint) to support system voltage and reactive power balance.

Additionally, SC contingencies must be considered in system planning and operational studies. Specifically, SC failures should be included in NERC Categories P1 and P3 contingencies to evaluate their impact on system reliability and stability.

7.7.2 Dynamic Model

For dynamic stability studies, SCs are modeled as synchronous machines without a prime mover, using standard synchronous generator models that accurately capture their transient and dynamic behavior. The key modeling parameters include:

- **Inertia Constant (H):** Represents the inertial response of the SC, which contributes to frequency stability by resisting sudden changes in system frequency.
- **Excitation System:** Governs voltage regulation and dynamic reactive power control to maintain system voltage stability during disturbances.
- **Damping and Governor Dynamics (if applicable):** Though SCs lack prime movers, certain models may include damping elements to accurately simulate their response in transient conditions.

Similar to steady state studies, SC contingencies should be incorporated into NERC Categories P1 and P3 contingencies to assess their impact on system reliability, stability, and transient response following faults or operational changes.

7.7.3 Short Circuit Model

In short circuit studies, SCs should be modeled as voltage controlled current source (VCCS) such that they do not inject real current into the grid.

7.7.4 Electromagnetic Transients (EMT) Model

For EMT studies, SCs are represented using detailed synchronous machine models that capture their full electromagnetic and electromechanical behavior. These models include:

- **d-q Axis Representation:** Enables accurate simulation of SC interactions with power electronic converters, IBRs, and HVDC systems.
- **Sub-transient, Transient, and Steady-State Reactance:** Captures SC behavior across different time frames, including fault response and recovery dynamics.
- **External Excitation System:** The field voltage is applied directly to the machine model through an external exciter, simulating real-world control interactions.
- **Zero Mechanical Torque:** Since SCs do not have a connected mechanical load, the mechanical torque input is set to zero, ensuring an accurate representation of their operational characteristics.

EMT studies are essential for evaluating SC behavior in systems with high penetration of IBRs, weak grids, and power electronics-based components, as they provide detailed insights into transient interactions, harmonics, and fast-switching phenomena that could impact overall grid stability.

8. Voltage Source Converters

8.1 Introduction

Voltage Source Converter (VSC) technology is a power electronics-based conversion system widely used in power systems. It has emerged as a key innovation in modern power systems, enabling efficient and flexible control of electrical energy transmission and distribution systems. Unlike traditional Line Commutated Converters (LCCs), which depend on thyristors and require strong AC networks, VSCs utilize fully controllable semiconductor devices such as IGBTs or Metal-Oxide-Semiconductor Field-Effect Transistors (MOSFETs). This capability allows VSCs to regulate both active and reactive power independently, thereby improving power network stability and reliability, particularly in weak grid conditions⁹³. A VSC can operate in rectifier mode (AC to DC conversion) or inverter mode (DC to AC conversion). By maintaining a controlled voltage at its DC side, VSC technology enables bidirectional power flow, enhancing its flexibility in grid applications.

VSC technology is widely applied in HVDC systems, FACTS, inverter-based resource (IBR) integration, and industrial applications. In HVDC transmission, VSC-HVDC systems provide advantages such as black start capability, reduced footprint, and the ability to connect to asynchronous grids. In FACTS applications, VSC-based devices like Static Synchronous Compensators (STATCOMs) offer dynamic voltage support and stability enhancement. Moreover, VSCs play a crucial role in integrating IBRs such as wind and solar power by providing grid-forming and grid-following capabilities.

This report explores the fundamental principles of VSC technology, its operational characteristics, control strategies, and diverse applications in modern power systems. The objective is to provide a comprehensive understanding of VSC technology and its role in advancing grid infrastructure and energy transition.

8.2 Technology Background

VSC technology has significantly advanced power electronics, enabling precise and independent control of active and reactive power. Its development has been driven by innovations in power semiconductor devices, control methodologies, and modulation strategies. Below is a detailed exploration of its technological foundation.

⁹³ N. Hatziaargyriou, "Stability definitions and characterization of dynamic behavior in systems with high penetration of power electronic interfaced technologies," *IEEE PES Technical Report PES*, 2020.

8.2.1 Evolution of Power Electronics and VSC Development

The concept of voltage source conversion has progressed through several key phases:

- **Early Power Converters (1950s–1970s): Thyristor-Based LCC Technology⁹⁴:** The first breakthrough in power electronics came with the development of silicon-controlled rectifiers (SCRs), also known as thyristors, in the 1950s. Thyristor-based Line LCCs became the dominant technology for HVDC transmission and industrial drives. However, LCC technology had limited control over reactive power and relied on a strong AC system for commutation, making it less flexible in weak grids. These converters were also prone to commutation failures.
- **Emergence of Self-Commutated Devices (1980s–1990s): Introduction of GTOs & IGBTs⁹⁵:** Gate Turn-Off Thyristors (GTOs) emerged in the 1980s, allowing self-commutation (i.e., turning off without relying on an external AC source) and independent control of active and reactive power in various applications. The IGBT was introduced in the late 1980s and early 1990s, offering improved switching capabilities with lower control power requirements, paving the way for VSC technology.
- **Rise of VSC-Based Systems (2000s–Present): Multi-Level Converters & Wide Bandgap Semiconductors:** The 2000s saw widespread adoption of VSC-based HVDC systems for offshore wind integration and weak-grid connections. Multi-level converter (MLC) topologies, such as Modular Multilevel Converters (MMC), significantly reduced switching losses and improved efficiency. Advances in Silicon Carbide (SiC) and Gallium Nitride (GaN) semiconductors further enhanced VSC technology by allowing higher switching frequencies, lower losses, and compact designs.

8.2.2 Semiconductor Devices in VSC Technology

The performance and efficiency of VSC technology depend heavily on the power semiconductor devices used for switching operations. These devices enable bidirectional power flow, efficient control of active and reactive power, and operation in weak grid conditions. Over the years, advancements in power semiconductor technology have significantly improved the efficiency, voltage handling, and reliability of VSC-based systems. Some of the main semiconductor devices used in VSC technology are described below:

- **Insulated Gate Bipolar Transistors (IGBTs)⁹⁶:** The IGBT is one of the most widely used switching devices in modern VSC applications, such as HVDC lines, FACTS devices, and IBR integration. It combines the high-voltage capability of bipolar junction transistors (BJTs) with the fast switching

⁹⁴ B. R. Pelly, “Thyristor phase-controlled converters and cycloconverters,” *Wiley*, 1971.

⁹⁵ B. Wu, “High-power converters and AC drives,” *Wiley*, 2006.

⁹⁶ N. Mohan, T. M. Undeland, and W. P. Robbins, “Power electronics: converters, applications, and design,” *Wiley*, 2002.

and low drive power of MOSFETs. IGBTs are widely used in medium to high-power applications due to their high efficiency and controllability.

- **Metal-Oxide-Semiconductor Field-Effect Transistors (MOSFETs)**⁹⁵: MOSFETs are high-frequency switching devices commonly used in low-voltage VSC applications such as distributed energy resources and electric vehicles.
- **Gate Turn-Off Thyristors (GTOs)**⁹⁷: The GTO was one of the first self-commutated power devices, replacing conventional thyristors in some VSC applications, such as early-generation VSC-based HVDC and FACTS systems. However, GTOs have now been largely replaced by fast switching IGBTs in modern applications.
- **Wide Bandgap Semiconductors: Silicon Carbide (SiC) and Gallium Nitride (GaN)**⁹⁸: Recent advancements in wide bandgap semiconductor materials have led to the development of SiC and GaN devices, which outperform traditional silicon-based IGBTs and MOSFETs in many aspects such as providing higher power density, reduced switching losses and the ability to operate at higher temperatures. While IGBTs remain dominant in modern VSC applications, SiC and GaN-based devices are shaping the next generation of power converters, offering superior efficiency and performance.

8.2.3 VSC Operating Principles

A VSC is an electronic power device that converts electrical power between AC and DC using pulse-width modulation (PWM) or other advanced switching techniques. It operates based on the principle of maintaining a controllable voltage source at its DC terminal, enabling bidirectional power flow and independent control of active and reactive powers. The core of VSC functionality lies in its operating modes, modulation strategy, topologies, and control systems.

8.2.3.1 Operating Modes

A VSC can operate in two primary modes:

- **Inverter Mode (DC to AC conversion)**: In this mode, VSC converts power from a DC source, e.g., an HVDC transmission line or a DC bus, into an AC output synchronized with the grid. This mode is essential for grid integration of IBRs or HVDC transmission terminals.
- **Rectifier Mode (AC to DC conversion)**: In this mode, VSC converts incoming AC power from the grid into DC power. This is useful in applications like HVDC sending-end stations, battery charging systems, or energy storage.

⁹⁷ L. Zhang, L. Harnefors, and H.P. Nee, “Power electronics for modern wind turbines,” *Springer*, 2012.

⁹⁸ M. K. Das, “Silicon carbide (SiC) power devices and applications,” *IEEE Transactions on Industry Applications*, 2020.

Because VSCs use self-commutated devices like IGBTs, both modes can be executed seamlessly and bidirectionally, allowing for dynamic grid support and enhanced stability. The bidirectional functionality of the VSC technology enables flexible energy exchange between AC and DC systems, which is crucial for energy storage, microgrid applications and black start capability.

8.2.3.2 Modulation Strategies⁹⁹

Modulation is at the core of VSC operation, which controls how the semiconductor switches are turned on/off to synthesize the desired output waveform. The most common modulation strategies include:

- **Pulse Width Modulation (PWM):** The most common approach, where the switching frequency determines waveform quality.
- **Space Vector Modulation (SVM):** Provides better DC voltage utilization and lower harmonic distortion compared to PWM.
- **Selective Harmonic Elimination (SHE):** Used in applications requiring minimal harmonic distortion.

8.2.3.3 Control Techniques

VSCs rely on sophisticated control strategies to ensure stable, efficient, and flexible operation in various power system environments. These strategies enable VSCs to independently regulate active and reactive powers, manage a stable DC link voltage, synchronize with the AC grid, and provide grid support services such as voltage regulation, frequency support, black start capability, fault ride-through (FRT), and dynamic support during transients. These objectives are typically achieved using a hierarchical control structure that has three different loops¹⁰⁰:

- **Primary (Inner Loop) Control**
 - Fast-response control of currents or voltages.
 - Ensures fast dynamic performance and system stability.
 - Implemented using PI controllers or vector control techniques in a rotating (d-q) reference frame.
 - Most VSCs use current control for fast and decoupled control of active and reactive power.
- **Secondary (Outer Loop) Control**
 - Manages power flow (active and reactive) and DC voltage regulation.
 - Reference values for current/voltage are generated based on system demand.

⁹⁹ M.H. Rashid, "Power electronics: circuits, devices and applications," *Pearson*, 2014

¹⁰⁰ R. Teodorescu, M. Liserre, and P. Rodriguez, "Grid converters for photovoltaic and wind power systems," *Wiley*, 2011.

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- **Tertiary (Supervisory or Energy Management) Control**
 - Optimizes power dispatch, coordinates multiple converters.

The other control techniques required for achieving different functionalities of VSCs include:

- **DC-Link Voltage Control¹⁰¹**: In a VSC, one terminal is usually assigned to control the DC voltage. This is essential for maintaining the power balance between the AC and DC sides. The DC voltage controller adjusts the active power reference in the outer control loop:
 - If DC voltage increases, then the power injection to the AC grid is reduced.
 - If DC voltage drops, then the power injection from the AC grid is increased.

This mode is critical in VSC-HVDC systems, where one converter station controls DC voltage, and the other controls power flow.

- **Reactive Power and Voltage Control**: Reactive power control is typically implemented in the q-axis of the control system. VSCs can operate in different modes based on grid requirements:
 - Voltage Control Mode: Maintain a constant AC voltage at the point of common coupling (PCC).
 - Reactive Power Control Mode: Maintain a desired level of reactive power.
 - Power Factor Control Mode: Maintain a constant power factor.

This makes VSCs ideal for grid support, voltage stabilization, and IBR integration.

- **Grid-Forming and Grid-Following Control¹⁰²**: In grid-following mode, VSCs use a Phase-Locked Loop (PLL) to synchronize with the AC grid voltage. A PLL tracks the grid voltage angle, frequency, and magnitude, and ensures the control reference frame is properly aligned with the grid. A robust PLL is essential for FRT, voltage regulation and weak grid operation.

In grid-forming mode, VSC does not rely on an external voltage reference, but instead generates its own voltage waveform providing a stable voltage and frequency reference for other sources and loads to synchronize. This enables VSCs to be used for black start, islanded operation in microgrids and reliably interconnect IBRs in weak grids. Grid-forming VSCs act as a virtual synchronous machine using droop control or synthetic inertia.

¹⁰¹ D. Jovcic and K. Ahmed, "High voltage direct current (HVDC) transmission systems for large offshore wind farms," *Energy*, 2009.

¹⁰² M. H. J. Bollen, "Understanding power quality problems: voltage sags and interruptions," *Wiley*, 2000.

8.2.3.4 VSC Topologies

VSC technology has evolved significantly over the past few decades, leading to the development of various topologies to suit different power system requirements. These topologies define the structure of the converter circuits and play a vital role in determining their voltage levels, efficiency, harmonic performance, modularity, and applicability in HVDC, FACTS, or renewable energy integration.

- **Two-level VSC**¹⁰³
 - Simple topology, but with higher switching losses and output harmonics
 - More applicable for low to medium power applications
- **Three-Level VSC (Neutral Point Clamped - NPC)**¹⁰⁴
 - Complex control system and requires additional components
 - Better performance at higher voltages than two-level converters
 - Lower total harmonic distortion (THD)
 - Suitable for industrial applications and STATCOMs
- **Modular Multilevel Converter (MMC)**¹⁰⁵
 - Ideal for high-power HVDC transmission
 - Consists of cascaded submodules per phase
 - Allows scalable voltage handling without increasing individual device ratings
 - Very low harmonic distortion, often eliminating the need for filters
 - Highly modular and scalable
 - Reduced dv/dt stress and lower switching losses
 - Fault-tolerant (redundancy can be built-in)
 - Complex control and communication system required
 - Expensive as compared to two- or three-level converters
- **Cascaded H-Bridge (CHB) Converter**¹⁰⁶
 - Consists of multiple single-phase full-bridge submodules per phase, with separate isolated DC sources (common in solar PV or battery systems)
 - Suitable for low-frequency transformer-less applications
 - Low harmonics and no need for phase transformers
 - Ideal for distributed generation
 - Complex voltage balancing and control

¹⁰³ N. Mohan, T. M. Undeland, and W. P. Robbins, "Power electronics: converters, applications, and design," Wiley, 2002.

¹⁰⁴ J. Rodriguez, et al., "Multilevel converters: an enabling technology for high-power applications," *IEEE Proc.*, 2009.

¹⁰⁵ R. Marquardt, "Modular multilevel converter: an universal concept for HVDC-networks and extended DC-bus-systems," *IEEE Power Electronics Conference*, 2010.

¹⁰⁶ S. Kouro, et al., "Recent advances and industrial applications of multilevel converters," *IEEE Trans. on Industrial Electronics*, 2010.

8.3 Applications and Benefits

VSCs operate by dynamically regulating their output through advanced switching and control methods. Their ability to convert and regulate AC/DC power in both directions, coupled with fast dynamic response and flexibility, makes them a cornerstone of modern power systems, especially in HVDC transmission, renewable integration, microgrids, and FACTS devices. Some of the applications and benefits of VSC technology are discussed next.

8.3.1 HVDC Transmission System (VSC-HVDC)

One of the most significant applications of VSC technology is HVDC transmission systems, which have greatly enhanced efficiency of long-distance power transfer. A key advantage of VSC-HVDC over traditional LCC-HVDC systems is its ability to support weak grid networks. VSC-HVDC systems are particularly beneficial for:

- **Grid Connection of Offshore Wind Farms and IBRs:** Due to grid-forming capability, voltage support, and black start capability, VSC-HVDC has been widely used for reliable power transmission from offshore wind farms to main grid.

An example of the use of VSC-HVDC to reliably transmit power from offshore wind farms to the main grid includes the BorWin1 HVDC project by TenneT, the first HVDC facility in the world which connects a wind farm to the power grid using HVDC technology¹⁰⁷. This project by ABB transmits up to 400 MW of clean energy from the BARD Offshore 1 wind farm via an HVDC cable system through the North Sea and overland to the onshore converter station in Diele.

- **Underground and Submarine Cable Transmission:** VSC-HVDC is ideal for long-distance power transmission via underground and submarine cables, where AC transmission would cause high reactive power losses. This can be used in densely populated urban areas where overhead lines are impractical and for island interconnections to ensure stable power exchange between isolated grids. VSC-HVDC also enables long-distance interconnections between countries, improving grid reliability and market efficiency.

An example of the use of the VSC-HVDC for this application includes the NordBalt project, which consists of 250 miles of submarine power cable installed between Klaipėda in Lithuania and Nybro in Sweden, operating since 2015. The maximum capacity of this project is 700 MW¹⁰⁸.

- **Multi-Terminal and DC Grid Development:** Traditional LCC-HVDC systems primarily operate in a point-to-point configuration, whereas VSC-HVDC enables multi-terminal and meshed DC grid configurations. Multi-terminal HVDC allows several converters to be connected in a flexible power

¹⁰⁷ “BorWin1 200-kilometre-long and 400-megawattstrong direct current connection,” *TenneT*. [Online]. Available: [Link](#).

¹⁰⁸ “NordBalt, the Baltic sea,” *NKT*. [Online]. Available: [Link](#).

transmission network and thereby enabling a large-scale renewable integration and efficient power routing.

An example of this includes Zhangbei HVDC power transmission project in China, which is the world's first HVDC power transmission system to utilize multi-level VSC technology. This project has four interconnected converter stations in a ring network with a transmission capacity of 4.5 GW and the length of the DC line is 648 km operating at ± 500 kV¹⁰⁹.

- **Grid Connection for Remote and Weak Networks:** Unlike LCC-HVDC, VSC-HVDC does not require a strong synchronous voltage source to operate and therefore can provide a stable connection to weak or passive networks, such as remote communities or industrial facilities. It enhances grid stability by providing voltage and frequency support and enables black start capability.

An example of this application of VSC-HVDC includes the Trans Bay cable (TBC) in California. This project consists of Siemens HVDC PLUS system using Modular Multilevel Converter (MMC) topology, with a maximum power transfer capacity of 400 MW and an operating voltage of ± 200 kV. VSC technology was selected for this project due to its suitability for connecting to weak or passive grids, such as San Francisco's urban load center, and its compact design, ideal for space-constrained urban environments. In 2018, Siemens upgraded the system's controls to enable black start functionality, allowing the TBC to independently power critical infrastructure in San Francisco as the sole source of power, without relying on the local grid¹¹⁰.

8.3.2 Industrial Applications

This section covers industrial applications of VSC:

- **Electric Arc Furnaces (EAFs) and Metal Processing:** VSC-based solutions regulate power quality in electric arc furnaces used in steel and metal industries. They help reduce voltage flicker, improve energy efficiency, and stabilize the supply network.
- **Mining Operations:** VSCs power underground mining equipment and conveyor systems, ensuring stable voltage supply in remote locations. They are also used in DC microgrids for efficient power distribution in mines.
- **Railway Electrification:** Many railway networks require stable and controlled DC power for train operations. VSC-based converters improve voltage stability and power quality in rail traction systems. Regenerative braking systems in electric trains use VSCs to recover and reinject power back into the grid.
- **Oil and Gas Industry (Offshore Platforms and LNG Facilities):** Offshore oil and gas rigs often rely on VSC-HVDC to receive power from mainland grids, reducing the need for on-site generation.

¹⁰⁹ "Zhangbei VSC-HVDC power transmission project," *NS Energy*, 2020. [Online]. Available: [Link](#).

¹¹⁰ "Trans Bay Cable project," *Babcock & Brown*, 2007. [Online]. Available: [Link](#).

VSC-based frequency converters are used in liquefied natural gas (LNG) plants to match different power frequencies (e.g., 50 Hz to 60 Hz conversion).

- **Industrial Drives and Motor Control:** VSCs enable precise speed and torque control in industrial motors and pumps, enhancing efficiency in manufacturing and processing industries. Their high dynamic response makes them essential in robotics, paper mills, and textile industries.

8.3.3 Integration of Renewable Energy Sources

VSC converters are crucial in integrating wind, solar, and battery storage systems into modern power networks. They provide essential grid services such as frequency regulation, dynamic voltage support, and black start support. VSCs enable grid-forming operation, which is especially valuable for maintaining stability in weak or islanded grids. Additionally, their bidirectional power flow capability allows efficient charging and discharging of batteries, enhancing the flexibility and resilience of the power system by providing peak shaving and load leveling grid support.

8.3.4 FACTS and Grid Stability

VSCs are commonly used in several FACTS devices that enhance the stability and controllability of the power systems grid.

- **VSC-based STATCOMs** is a type of shunt-connected FACTS device that provides fast and dynamic reactive power compensation and voltage support in AC networks. They improve system reliability by mitigating voltage fluctuations, harmonics, and power oscillations.
- **VSC-based Static Synchronous Series Compensator (SSSC)** is a series-connected FACTS device that uses a VSC to inject a controllable voltage in series with a transmission line. The injected voltage is in quadrature (90° phase shift) with the line current and is used to control power flow dynamically and improve system stability. SSSC supports grid with active power flow control, reactive power compensation, and damping of power oscillations. The fast response of VSCs enables the SSSC to dampen the sub-synchronous resonance in series-compensated lines.

VSC based FACTS devices are widely used in the USA and other parts of the world to support reliable grid operations. One such example is the Gates 500kV Dynamic Reactive Support Project in California¹¹¹. It involves the construction of the Orchard Substation, which will house two STATCOM units. These devices will regulate voltage and support grid stability, specifically for the nearby PG&E Gates Substation, which operates at 500 kV and 230 kV. The project aims to provide dynamic reactive power support, ensuring the reliable operation of the extra high voltage transmission system.

¹¹¹ “Gates 500 kV dynamic reactive support description and functional specifications for competitive solicitation,” CAISO, 2019. [Online]. Available: [Link](#).

8.3.5 Microgrids and Islanded Systems

VSCs enable seamless operation of microgrids, allowing them to operate in both grid-connected and islanded modes. They provide synthetic inertia and frequency regulation, critical for modern decentralized power networks.

The University of California, San Diego microgrid is a prime example of VSC technology being used to enhance the operation of microgrids, especially for integrating IBRs and improving grid resilience. It demonstrates how VSC-based converters can be a critical technology in creating self-sustaining, flexible, and reliable microgrids.

In 2015, Kodiak Island became the first U.S. community to achieve a 100% renewable energy supply. This milestone was made possible using VSC-based converters, which facilitated the smooth and reliable integration of solar and wind energy, battery storage, and diesel backup systems. VSC technology plays a vital role in Kodiak Island microgrid operations by providing precise control of voltage and frequency, an especially critical capability for remote and isolated locations like Kodiak Island.

8.3.6 Effects on Various Types of Grid Violations

VSC technology offers targeted solutions to a broad range of reliability challenges in transmission systems. Their impact can be categorized according to the three primary classes of reliability violations: thermal, stability, and voltage.

- **Thermal Violations:**
 - Dynamic Power Flow Control: VSCs can independently and rapidly control active and reactive power, optimizing power flow and mitigate thermal overloads on transmission lines.
- **Voltage Violations:**
 - Reactive Power Support: VSCs can provide dynamic reactive power compensation, stabilizing voltage levels during fluctuations or faults.
 - Voltage Regulation in Weak Grids: In regions with weak grids, VSC-HVDC systems can maintain voltage stability, facilitating the integration of renewable energy sources.
 - Compact and Modular Design: MMC offers scalable and compact solutions with reduced harmonic distortion and lower filter requirements, enhancing voltage quality.
- **Stability Violations:**
 - Damping Electromechanical Oscillations: By modulating active and reactive power, VSCs can suppress electromechanical oscillations, enhancing rotor angle stability.
 - Fast Frequency Response: VSC-HVDC systems can provide rapid frequency support during disturbances, improving transient stability and preventing frequency-related issues.
- **Operation in Weak Grids:** VSCs can operate in weak or passive grids without the need for a strong synchronous voltage source, maintaining stability in areas with low short-circuit capacity.

Table 25 summarizes the degree of impact VSCs have on addressing various grid reliability challenges:

Table 25: Degree of Impact of VSCs on Grid Reliability Challenges.

Thermal Violations	Voltage Violations	Stability Violations
Notable	Notable	Notable

8.4 Technical and Operational Considerations

With the increasing penetration of IBRs in the grid, VSC technology is playing a critical role in the reliable integration of these resources. However, it is essential to take into consideration several factors before the deployment of VSCs.

8.4.1 Grid Integration and Interoperability

The integration of VSC systems into existing AC transmission networks requires careful attention to compatibility with local grid conditions, operational practices, and regulatory standards. As discussed in Section 8.3, VSCs are particularly well-suited for interfacing with weak grids or remote renewable generation sites due to their ability to operate without a strong synchronous voltage source. Their fast-acting controls allow for dynamic support of system voltage and frequency, facilitating the stable integration of variable resources such as wind and solar.

However, VSC systems contribute limited short-circuit current, which can affect traditional protection schemes based on fault current magnitude. This requires re-evaluation of protection coordination and may involve integrating fault current limiters or upgrading protective relays. While MMCs produce lower harmonic distortion than earlier VSC designs, harmonic filtering and system studies may still be necessary to ensure compliance with power quality standards, especially in sensitive industrial or urban environments. These interoperability considerations are essential to ensure that VSC systems function harmoniously within broader transmission networks.

8.4.2 Reliability and Maintenance

Reliability is a key advantage of VSC systems, particularly those using modular architectures such as MMCs. The redundancy built into modular submodules allows for continued operation even in the presence of individual component failures, reducing the likelihood of system-wide outages. This design, combined with robust thermal management and high-quality components, enhances long-term operational performance. VSC installations also typically incorporate real-time condition monitoring, enabling utilities to adopt predictive maintenance practices that reduce unplanned downtime and optimize asset life cycles.

Maintenance procedures for VSCs benefit from the modularity of the equipment, which simplifies repair and replacement activities. Faulty submodules can often be swapped without requiring a complete system shutdown, minimizing service interruptions. Additionally, modern VSC systems support remote

diagnostics and automated fault detection, allowing operators to quickly identify issues and dispatch maintenance resources efficiently. These features contribute to a lower total cost of ownership and improved service continuity compared to traditional HVDC technologies.

8.4.3 Cybersecurity and Digital Control

As VSC systems rely on sophisticated digital control platforms for real-time power modulation, protection, and communication, cybersecurity becomes a critical operational concern. The integration of VSCs with SCADA, EMS, and remote control systems exposes them to potential cyber threats that could disrupt power delivery or compromise sensitive grid data. To mitigate these risks, VSC deployments must include robust cybersecurity frameworks, such as encryption of control signals, secure authentication protocols, and firewalled communication gateways.

Moreover, the increasing reliance on remote operation and automated functionality introduces both opportunities and challenges. Remote diagnostics and firmware updates enhance operational flexibility and reduce the need for onsite personnel, but they require highly secure and resilient communication infrastructure. Adherence to North American Electric Reliability Corporation Critical Infrastructure Protection (NERC CIP) standards or equivalent cybersecurity guidelines is essential for ensuring grid reliability and protecting critical infrastructure. In this digital landscape, operational resilience is as much about cyber-physical integration as it is about hardware robustness.

8.4.4 Utility-Wide Impacts of VSC Deployment

The integration of VSC technology affects key areas within a utility, including generation interconnection, transmission planning, system protection, operations, and engineering design. A comprehensive understanding of the role and impact of VSCs across utility departments is essential for effective deployment, operational reliability, and long-term system planning. This section outlines the specific considerations each department must account for when integrating VSCs into the power grid.

8.4.4.1 Generation Interconnection

From a generation interconnection perspective, VSC technology can be used to reliably interconnect IBRs at remote locations to the main grid. Grid-forming VSCs might be a feasible alternative to conventional upgrades, if grid strength at the point of interconnections is weak.

VSCs can also interact with other dynamic devices like STATCOMs, HVDC systems, and IBRs resulting in control-based oscillations, reactive power conflicts, etc. Therefore, if there are other devices in proximity to the VSC, a thorough assessment needs to be performed to ensure no grid reliability issue arises because of the control interaction between these devices.

8.4.4.2 Transmission Planning

VSCs play a crucial role in modern transmission planning in HVDC transmission. Once a violation is identified in transmission system, a thorough transmission planning study is needed to evaluate the effectiveness of VSC technology in mitigating the violation. VSC-HVDC system is studied to understand its

impact on system stability including control interaction with other controllers in proximity to the VSC-HVDC. These HVDCs can also be used as damping controllers, thereby affecting system small-signal stability and requiring a system impact study. VSC-HVDCs usually transfer high power across long distances; therefore, it is important to study the contingencies involving these converters on system reliability.

8.4.4.3 System Protection

VSCs have a notable impact on system protection in both planning and operations timeframe. Due to the limited fault current capabilities of VSCs, the traditional protection scheme, such as overcurrent and distance protection schemes, may not work as intended and could potentially result in miscoordination, or even complete failure to detect and isolate faults near VSC terminals.

VSCs can respond fast to grid disturbances by changing their output, phase angles and voltage magnitudes rapidly. While this enables robust voltage support and system stabilization, it may also confuse traditional directional relays and transient-sensitive protection elements, thereby posing additional issues when using traditional protection schemes.

Therefore, a thorough study needs to be done to understand the impact of the VSCs on protection schemes to ensure that protection systems remain secure, selective, and dependable in the evolving landscape of power electronics-dominated networks.

8.4.4.4 Operation and Control Systems

In the operations timeframe, use of VSCs will be critical for controlling active power flows and for providing voltage and frequency stability support. As VSCs can independently control both active and reactive power, VSCs provide operational flexibility and overall stability during periods of grid disturbances by providing fast, dynamic support to the grid, thereby reducing the time required by operators to restore and maintain a stable, reliable system. Since grid-forming VSCs also have the capability of black-start, these VSCs can play a critical role in restoring the system during system-wide outage.

8.4.4.5 Engineering and Design

The installation of VSCs introduces significant modifications to the engineering and design of transmission systems and substations. The installation of VSC requires a dedicated filtering system to filter out the high frequency switching harmonics caused by PWM. Therefore, substation design must include harmonic filters either integrated into converter or as dedicated bays. Grounding and shielding for harmonic containment and electromagnetic compatibility (EMC) are critical as well. The substation may require electromagnetic shielding and segregation of control/power cables to mitigate interference from high-frequency switching. Earthing systems must be robust to handle converter stray currents and provide low-impedance paths for Electromagnetic Compatibility (EMC) compliance.

VSCs typically connect to the AC system via interface transformers, often with delta/star or delta/delta configurations. This must be taken into consideration when installing VSCs. The transformer design may also need to consider magnetizing inrush, harmonic flux, and voltage regulation (e.g., with tertiary

windings for filtering). Besides, the VSC system must have a dedicated protection scheme, particularly on the DC side, for fast fault detection. On the AC side, the protection scheme needs to consider the reduced fault current limit of the VSCs. The VSC station may require additional equipment, particularly for VSC-HVDCs, such as converter buildings, colling systems, such as air or water cooled, control systems, filter banks and reactors.

VSC installation also requires communication infrastructure to ensure high-speed redundant communication links between VSC control system and central dispatch, converter stations in multi-terminal setups and protection systems for DC and AC-side fault handling. IEC 61850 is often used for substation automation, but with enhancements for VSCs.

8.4.4.6 Summary of Utility-Wide Impacts

Table 26 summarizes the impact of VSC technology across various utility departments.

Table 26: Utility-Wide Impacts of VSC Technology.

Utility Function	Impact Level	Primary Benefits of VSC Deployment
Generation Interconnection	High	Enables reliable interconnection in weak grids; supports renewables; mitigates control interactions with nearby devices.
Transmission Planning	High	Supports mitigation of thermal, voltage, and stability violations; enhances transfer capacity and damping; enables contingency planning.
System Protection	Medium to High	Requires adaptation of traditional schemes; fast dynamic response; limited fault current affects coordination.
Operations and Control	High	Provides dynamic voltage/frequency support; enhances grid resilience; enables black-start capabilities and real-time control.
Engineering and Design	High	Involves major changes in substation layout; requires harmonic filtering, EMC compliance, and advanced communication infrastructure.

8.5 Best Practice

This section presents real-world examples of VSC technology implementation, and the lessons learned from these applications.

8.5.1 Zhangbei HVDC Power Transmission Project in China

Zhangbei HVDC power transmission project is the world's first HVDC power transmission system to utilize multi-level VSC technology. This project highlights how multi-converter VSC-HVDC can be used to integrate different energy resource types and facilitate power transfer across long transmission lines. This project enabled the integration of wind, solar, and hydro energy systems through a four-terminal transmission ring network. Some of the lessons learnt from this project are:

- **Complex control-coordination in VSC-HVDC is achievable**
 - This project coordinates power flow among four terminals, each capable of varying power and operating modes.
 - The control was achieved by using a hierarchical control structure such that primary control handles voltage/power regulation and secondary/tertiary control coordinates overall power dispatch.
 - High-speed communication and low-latency control links essential for synchronization of converters
 - Droop control allows decentralized decision-making during disturbances.
- **Fault handling in multi-terminal HVDC is challenging**
 - DC faults can propagate quickly across terminals.
 - Use of fast DC fault detection and isolation techniques (e.g., DC circuit breakers and converter blocking control) was used in this project.
 - Design of selective fault clearing to avoid full-system shutdown.
 - Extensive real-time simulation testing (RTDS, HIL) is required to validate protection coordination.
- **Grid-forming capability is vital for weak grid integration**
 - At least one or more of the VSC terminals in the Zhangbei project were configured to operate in grid-forming mode.
 - The remote terminals (e.g., in Zhangbei, rich in wind and solar but weak in synchronous generation) had weak or no strong AC voltage references.
 - The converter had to establish voltage and frequency reference for local renewable generation and local loads.
 - This enhances system stability during faults or when parts of the system operate in island mode.
 - But this also requires robust control tuning to avoid oscillations and maintain synchronization across terminals.

- **Harmonic filtering needs careful design even with MMC**
 - Although MMCs generate lower harmonics, resonances and interactions with the AC grid can still occur.
 - Perform thorough harmonic impedance scanning.
 - Use passive filters or active damping controls where needed, especially in weak grids.
- **Converter reliability and redundancy are crucial**
 - High power and long transmission routes demand extreme reliability.
 - Incorporate submodule-level redundancy in MMCs for continuous operation during module failures.
 - Use of hot-swappable components and predictive maintenance systems improved uptime.
- **Cybersecurity and communication infrastructure are critical**
 - Secure, redundant communication for control coordination and SCADA is critical for reliable operations.
 - A dedicated optical fiber network was used with redundant paths in this project.
 - Emphasis on cybersecurity hardening of converter stations and control centers.

8.5.2 DolWin1 Offshore Wind Connection in Germany

DolWin1 Offshore Wind Connection VSC-HVDC project in Germany connects North Sea wind farms to the onshore grid transferring power up to 800 MW. Some of the lessons learnt from this project include:

- **Harsh Environment:** Offshore platforms are exposed to extreme marine conditions. All components must be corrosion-resistant and maintenance-free for years.
- **Black Start Challenges:** While the VSC was designed for black start, practical issues like relay coordination and sequence delays prevented smooth implementation. Sequence tuning and load anticipation needed improvement.
- **AC Voltage Control:** Reactive power management was challenged by long HVAC export cables; converter needed to provide continuous voltage regulation, requiring dynamic tuning under variable wind output.
- **Startup Synchronization:** Wind farms and VSCs needed precise synchronization schemes; delays in wind farm inverter coordination resulted in converter oscillations.

8.5.3 South-West VSC-HVDC Link in Sweden

The South-West VSC-HVDC project in Sweden facilitates power transmission up to 1200 MW from Southern to central Sweden. Some of the lessons learnt from this project include:

- **Control and Protection Interoperability:** Delay in commissioning due to software integration bugs between local protection systems and the VSC control platform. Testing with live AC system simulations was missing.

- **DC Cable Installation:** Long DC cable route exposed to multiple soil types caused uneven thermal loading, requiring real-time temperature monitoring to avoid derating.
- **Converter Location Impact:** Proximity to high-reliability AC substations influenced layout design and fire safety protocols. Strong coordination with local utilities was essential.
- **Cybersecurity:** Early security audits identified vulnerabilities in remote SCADA links. Retrofitting encryption and firewall rules caused delays but are now considered standard best practice.

8.5.4 INELFE (France–Spain Interconnection) Project

INELFE Project interconnects France and Spain transmission system through the Pyrenees. This project is 64.5 km in length and supports power flow of up to 2 GW. Some of the lessons learnt from this project include:

- **EMC and Interference:** Proximity to railways and telecom infrastructure required advanced EMC design. EMC simulation should be part of the early design stage.
- **Modular Layout:** Converter building design was modular and future-ready, but grounding and shielding between compartments caused early noise issues, leading to design rework.
- **Commissioning Logistics:** Cross-border coordination required pre-defined joint test protocols and agreed-upon control modes. Language, regulation, and control philosophy differences added complexity.
- **Converter Redundancy:** Having redundant cooling and submodule bypass features greatly increased system availability.

8.5.5 VSC-based Microgrid in Borrego Springs, California

The Borrego Springs Microgrid, operated by San Diego Gas & Electric (SDG&E), is one of the most well-known utility-operated VSC-based microgrids in the United States. It's particularly notable for its successful use of VSC technology in real-world grid-forming, black start, and islanding applications. This project demonstrates the capability of micro grids to manage a community-scale, high amounts of IBRs with economic benefits. Some of the lessons learnt from this project include:

- **Mode Switching Stability:** Transitions between grid-connected and islanded operation require precise coordination of control modes. Poor tuning initially led to inverter tripping and load rejection.
- **Inverter Coordination:** Grid-forming inverter must establish voltage/frequency reference; PV inverters need to detect this quickly to reconnect. Some commercial PV inverters were too slow to resynchronize.
- **Load Forecasting:** Underestimation of evening load in some islanding events led to rapid State of Charge (SoC) depletion. Enhanced forecasting and load shedding algorithms were added.
- **Cybersecurity:** Early designs lacked robust encryption on remote control systems. SDG&E added firewalls, VPNs, and NERC-style protection.

- **Battery Thermal Management:** High desert temperatures caused thermal derating of battery inverters. Improved HVAC and SoC balancing strategies were introduced.

8.5.6 VSC in Renewable Energy Park in South Australia

The Port Augusta Renewable Energy Park (PAREP) is Iberdrola's first renewable energy facility in Australia. This hybrid wind and solar plant has a total installed capacity of 317 MW and is situated in South Australia's coastal region. The project consists of the installation of 50 wind turbines with unit capacity of 4.2 MW in a wind farm of 210 MW and a solar photovoltaic plant with 250,000 solar panels with an installed capacity of 107 MW. This project utilizes both grid-forming and grid-following VSC inverters. Some of the lessons learnt from this project include:

- **Weak Grid Performance:** VSCs in grid-forming mode stabilized local microgrids even during major transmission outages.
- **Inertia Emulation:** VSCs using synthetic inertia algorithms helped prevent frequency collapse during generation drops.
- **Coordination with Synchronous Machines:** Conflicts between virtual and physical inertia led to overshoots, coordination logic was improved with hybrid inertia control.
- **Weather Variability:** Power electronics needed derating during extreme heat waves to prevent overheating.

8.6 Challenges and Barriers

Despite the benefits of VSCs, several challenges hinder their widespread adoption. Some of the challenges encountered in technical, economic, regulatory, and operational.

8.6.1 Technical Challenges

VSC systems introduce a new set of technical complexities that must be carefully managed to ensure reliable performance:

- **Limited Fault Current Contribution:** VSCs inherently provide limited fault current during short-circuit events due to their controlled nature. This poses significant challenges for conventional protection schemes, such as overcurrent or distance protection, which rely on high fault current magnitudes for accurate detection and coordination.
- **Control Interactions and Stability Risks:** VSCs depend on sophisticated control algorithms to manage real and reactive powers, voltage, and frequency. In high IBR penetration scenarios, especially in weak grid conditions, there is a heightened risk of adverse control interactions and small-signal instability. These issues are exacerbated when multiple VSCs from different vendors operate in close electrical proximity, as lack of standardization across control schemes can lead to uncoordinated responses, resonance, or oscillatory behavior.
- **Harmonic Emissions and Electromagnetic Interference:** The high-frequency switching nature of VSCs leads to the generation of harmonics and electromagnetic interference (EMI), which can

affect the performance of nearby equipment and communication systems. This necessitates careful design of harmonic filters, electromagnetic shielding, and robust grounding systems to maintain power quality and ensure EMC with existing infrastructure.

8.6.2 Capital Cost and Spatial Requirements

VSC systems involve high capital investment due to costly components like converters, cooling systems, filters, transformers, and advanced control equipment. Additionally, these components require a larger physical footprint, which can present further challenges for VSC deployment, especially in space-constrained areas.

8.7 Modeling Procedure

VSC models are widely available in modern power system simulation tools. These models vary in complexity depending on the type of study, steady state (power flow), dynamic stability, short circuit, or EMT, and they are typically implemented as part of built-in libraries or user-configurable blocks.

8.7.1 Steady State Model

In steady state studies, VSCs are represented as controlled power injections at converter buses, supplemented by components such as transformers and filters. PSS/E library includes a VSC-HVDC power flow model that allows users to specify control buses and define reactive power capabilities through QMAX and QMIN. This facilitates accurate modeling of VSC behavior under various operating conditions.

In addition, VSC can be modeled using generators capable of both positive and negative power outputs. This approach leverages user-defined dynamic models, providing enhanced flexibility and alignment with proprietary control strategies.

8.7.2 Dynamic Model

Dynamic modeling of VSCs in PSS/E is essential for assessing system stability and response to disturbances. Two library models are available for simulating VSC-HVDC systems: HVDCPLU1/HVDCPL1 and VSCDCT. While these models are functional for long-term planning studies, they exhibit limitations during fault simulations, particularly in capturing the nuanced behaviors of VSCs under transient conditions.

For project-specific analyses, user-defined models are recommended. These models offer detailed representations of converter dynamics, control schemes, and protection mechanisms, ensuring more accurate simulation outcomes. Additionally, WECC developed a generic VSC-HVDC model (vhvdc1), that can be utilized in dynamic modeling.

8.7.3 Short Circuit Model

Modeling VSCs for short-circuit studies presents unique challenges due to their limited fault current contributions and fast-acting controls. Traditional protection schemes, which rely on significant fault currents for operation, may not function as intended in systems with high VSC penetration. Therefore, accurate representation of VSC behavior during faults is crucial.

In PSS/E, short circuit modeling of VSCs often involves simplifying assumptions or the use of equivalent current sources to represent fault contributions. However, these methods may not capture the detailed dynamics of VSCs during fault conditions. For more precise analyses, EMT simulation tools like PSCAD are employed, offering detailed insights into VSC responses during faults.

9. Dynamic Line Rating

9.1 Introduction

A transmission line rating is the maximum current, apparent power, or real-power transfer that may be permitted on a facility under stated conditions. Although the term is often treated as a single number in a planning case or Energy Management System (EMS), a rating is the result of engineering assumptions about the line, its environment, and the consequence of exceeding a limit. For overhead conductors, the most common short-term physical limitation is thermal: current heats the conductor, the conductor expands and sags, and prolonged high temperature can degrade material properties and accessories. A safe rating therefore links electrical loading to conductor temperature, mechanical clearance, and equipment capability.

The U.S. Department of Energy describes DLR as an umbrella term for technologies and methodologies that determine conductor thermal ratings using more granular or real-time data. FERC distinguishes DLR from static and ambient-adjusted ratings by noting that DLR may use near-term forecasts of ambient temperature together with wind, cloud cover, solar intensity, precipitation, and line conditions such as sag or tension. In practical utility use, DLR may refer to an instantaneous calculated limit, a short-term forecast, a filtered operational rating, or a family of ratings with different confidence levels and time horizons.

9.1.1 Fundamentals of Transmission Line Ratings

The principal transmission line rating methodologies used in utility practice are summarized in Table 27.

The thermal rating of a bare overhead conductor answers a specific engineering question: what current can flow without causing the conductor temperature to exceed a selected limit under the assumed weather and operating conditions? The selected temperature limit may be controlled by ground clearance, crossing clearance, conductor annealing, connector performance, hardware capability, or utility policy. The weakest applicable element—not necessarily the conductor itself—sets the usable facility rating.

As conductor temperature rises, thermal expansion increases sag. If minimum clearances to ground, vegetation, buildings, railways, roadways, or other circuits are not maintained, the consequence can be flashover, public-safety exposure, or violation of design criteria. Higher temperature also increases conductor resistance, which further increases losses, and long periods at elevated temperature can reduce tensile strength or accelerate aging. Line ratings therefore serve both immediate reliability and long-term asset-health objectives.

A facility can also be limited by nonthermal phenomena. On long transmission lines, voltage or angular-stability limits may be lower than the thermal limit. Series compensation, protection reach, breaker capability, current transformers, wave traps, switches, jumpers, or terminal conductors may restrict the

facility below the calculated bare-conductor ampacity. DLR changes only the weather-dependent thermal component. Before a DLR rating is used, the utility must confirm that the dynamic conductor limit is not above another valid facility limitation.

Table 27: Principal transmission line rating methodologies

Rating approach	Primary basis	Key implication
Static Line Rating (SLR)	Fixed seasonal or annual weather assumptions	Simple, familiar, conservative; may understate or occasionally overstate actual capability.
Seasonal Rating	Separate fixed ratings for summer, winter, or other seasons	Captures broad temperature differences but not hourly weather variation.
Ambient-Adjusted Rating (AAR)	Forecast ambient temperature and updated day/night solar assumptions	More accurate than SLR; generally does not fully capture wind variation.
Dynamic Line Rating (DLR)	Ambient temperature plus wind and other weather and/or direct asset measurements	Most granular representation; requires data, forecasting, validation, integration, and fallback logic.

9.1.2 Scientific Basis: Conductor Heat Balance

The scientific foundation of line rating is an energy balance on the conductor. The governing thermal processes are illustrated conceptually in Figure 31. Current produces resistive or Joule heating. Sunlight adds absorbed solar heat. Heat is removed by convection to the surrounding air and by radiation from the conductor surface. Under icing or rain conditions, additional heat-transfer mechanisms may apply, but the four-term balance below is the core of standard bare-conductor rating calculations.

$$\text{Steady-state heat balance: } I^2R(T_c) + q_s = q_c + q_r$$

$$\text{Transient heat balance: } mC_p(dT_c/dt) = I^2R(T_c) + q_s - q_c - q_r$$

In these expressions, I is conductor current; $R(T_c)$ is the conductor's AC resistance at conductor temperature T_c ; q_s is solar heat gain; q_c is convective heat loss; q_r is radiative heat loss; m is conductor mass all per unit length; and C_p is specific heat. The steady-state equation is used when the current and weather have persisted long enough for conductor temperature to stabilize. The transient equation is used when current or weather changes faster than the conductor can reach equilibrium.

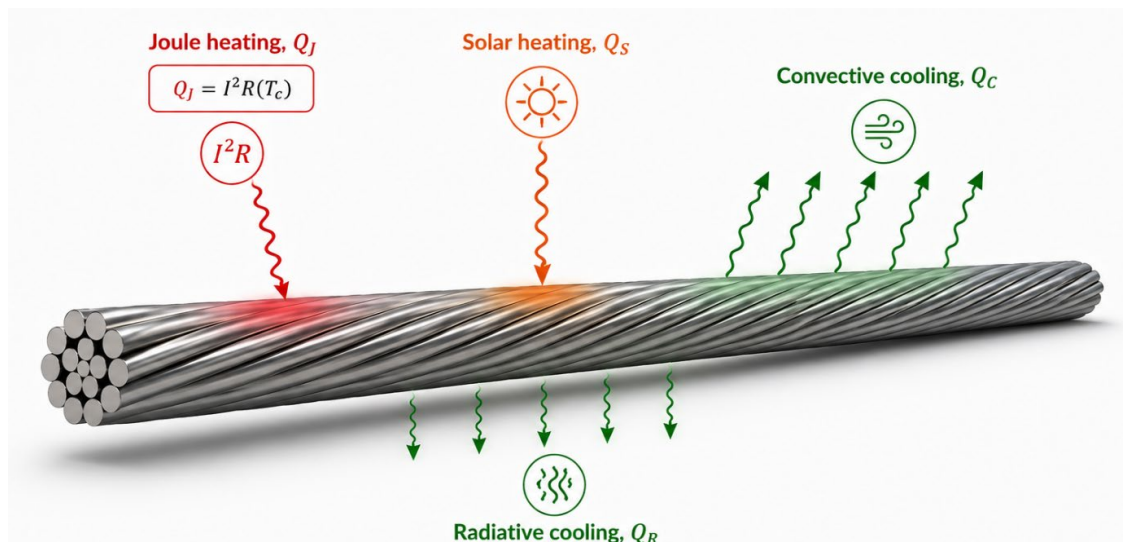


Figure 31: Conceptual heat-balance model for an overhead conductor. The figure is a schematic based on the heat-balance structure used in IEEE Std 738 and CIGRE thermal-rating methods

Joule heating increases approximately with the square of current. Resistance also rises with temperature, so there is a reinforcing effect: more current raises temperature, and higher temperature increases electrical losses. Solar gain depends on solar position, atmospheric conditions, conductor diameter, surface absorptivity, and line orientation. Radiative cooling depends strongly on the difference between the absolute temperatures of the conductor and its surroundings and on surface emissivity.

Convective cooling is often the dominant and most uncertain term. Even a modest crosswind can remove substantially more heat than the conservative low-wind assumption used for a static rating. Wind direction matters because wind normal to the conductor generally produces more effective cooling than wind parallel to the line. Turbulence, terrain, vegetation, buildings, span height, and local channeling can make wind highly variable along a corridor. This is why the critical thermal span may not be located near the nearest public weather station and why DLR deployments require careful siting or spatial modeling.

The DLR calculation is formulated to determine the maximum current that can be safely carried while maintaining the conductor temperature below its specified thermal limit under the prevailing or forecast environmental conditions. The resulting ampacity is subsequently adjusted using engineering filters, equipment limits, confidence margins, ramp-rate constraints, and fallback logic before being issued as the operational rating.

Thermal inertia is important. A conductor does not instantaneously reach its final temperature after a current increase. Depending on conductor size and weather, the response may take minutes to tens of minutes. This creates the possibility of short-time or emergency ratings above the continuous rating. However, using thermal inertia requires a time-dependent model, an accurate initial temperature estimate, a defined duration, and a control action that reduces loading before the temperature limit is reached.

The relative influence of the principal environmental variables governing conductor ampacity is summarized in Table 28.

Table 28: Influence of Key Environmental Variables on Dynamic Line Rating

Input	Typical influence on permissible current	Important qualifications
Wind speed	Higher wind generally increases convective cooling and ampacity.	Effect is nonlinear and sensitive at low wind speeds; local turbulence and sensor uncertainty matter.
Wind direction	Crosswind generally cools more effectively than wind parallel to the conductor.	varies by span; complex terrain can change local direction.
Ambient temperature	Lower ambient temperature generally increases allowable current.	Temperature alone does not capture wind-driven cooling; AAR is not equivalent to full DLR.
Solar radiation	Higher solar loading reduces available electrical heating margin.	Depends on time, cloud cover, latitude, line orientation, surface absorptivity, and day/night.
Conductor surface condition	Absorptivity and emissivity change with age and contamination.	New and aged conductors may behave differently; assumptions should be documented.
Maximum conductor temperature	Higher allowed temperature increases ampacity.	May be restricted by clearance, annealing, connectors, accessories, or utility policy.
Conductor resistance	Higher resistance produces more heating at the same current.	Resistance changes with temperature and conductor construction.

9.1.3 Static, Seasonal, Ambient-Adjusted, and Dynamic Ratings

Static ratings are calculated using a fixed set of weather assumptions and a selected conductor temperature. Many utilities maintain separate summer and winter ratings, and some use normal and emergency values. This approach is operationally straightforward and does not depend on communications or real-time measurements. Its limitation is that the same rating is applied through a wide range of actual conditions.

Static assumptions are often described as conservative, but this should not be interpreted as a guarantee that the static rating is lower than actual capability at every moment. If actual weather is more adverse than the assumed weather—for example, very low wind combined with high ambient temperature and strong solar heating—the instantaneous thermal capability can fall below the static rating. Static ratings are best understood as ratings designed to meet a chosen level of conservatism or risk, not as absolute real-time measurements.

Ambient-adjusted ratings update the permissible current based primarily on forecast ambient temperature and updated solar assumptions. They capture a major source of seasonal and diurnal variation without requiring the full sensor and forecasting architecture of DLR. FERC Order No. 881 established requirements for the use of AARs in near-term transmission service and market processes, while subsequent FERC proceedings have examined a potential framework for broader DLR implementation.

DLR incorporates additional drivers of heat transfer, particularly wind. A full DLR may also use direct conductor or mechanical measurements. Because wind can dominate convective cooling, DLR can identify substantial usable headroom that an ambient-temperature-only method misses. The tradeoff is greater complexity: wind must be measured or forecast at the relevant location and height, data quality must be checked, and the operational rating must be managed when forecasts or communications fail.

9.1.4 Importance of Dynamic Line Rating

The transmission system is experiencing rapid changes in both generation and demand. Renewable resources are frequently located far from load centers, and their interconnection can be constrained by existing corridor limits. Electrification, manufacturing growth, and data-center development can create large new load pockets on timelines shorter than those required to permit and construct major transmission upgrades. DLR offers a comparatively fast method of extracting more value from existing facilities when the binding constraint is weather-dependent conductor heating.

DLR can be especially synergistic with wind generation. Periods of high wind production may also provide enhanced convective cooling on nearby transmission corridors, although the relationship is site-specific and must be evaluated using spatially and temporally aligned data. The same principle can support offshore-wind and remote-renewable integration, but it should not be assumed without study: wind at a generating plant, wind at the critical line span, and system congestion may not occur simultaneously.

Beyond additional ampacity, DLR improves situational awareness. Sensor and weather data can reveal conductor temperature, sag behavior, icing, anomalous heating, or changes in line response. These data may support asset management and condition-based maintenance. Nevertheless, the core reliability requirement remains unchanged: operators must have a secure, validated rating and a conservative alternative whenever the dynamic system cannot provide one.

9.2 Technology Background

Dynamic rating is not a different law of conductor physics; it is a more information-rich application of the same thermal principles used to establish static ratings. The technology developed as utilities gained the ability to measure weather and conductor behavior along transmission corridors, communicate those data to control centers, and compute ratings frequently enough to influence operations. Its history is therefore closely tied to advances in sensing, telecommunications, numerical weather prediction, EMS integration, and regulatory treatment of transmission ratings.

9.2.1 Evolution of Line-Rating Practice

Early transmission-line ratings were derived from engineering calculations and conservative weather assumptions suitable for printed operating guides and manual dispatch. Utilities commonly developed fixed seasonal ratings because ambient temperature patterns were easy to characterize and because control centers had limited access to corridor-specific weather or conductor measurements. The practice was robust and manageable, but it treated environmental conditions as fixed for long periods.

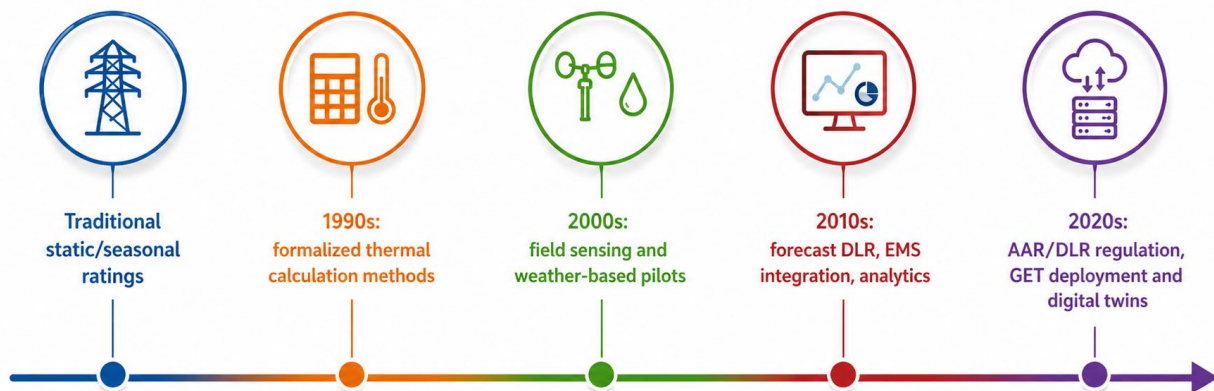


Figure 32: Simplified evolution of overhead line-rating practice. Dates indicate broad industry phases rather than a single invention date.

The thermal relationship between current, weather, and conductor temperature became progressively standardized. IEEE issued a formal standard for calculating the current-temperature relationship of bare overhead conductors by at least 1993, with later revisions in 2006, 2012, and 2023. CIGRE produced complementary guidance addressing weather-parameter selection, thermal rating calculations, high-temperature operation, and forecasting. These publications established a common technical foundation for both static and dynamic ratings.

Field demonstrations expanded in the 1990s and 2000s as utilities instrumented lines with weather stations, conductor-temperature sensors, tension or sag monitors, and communications.

During the 2010s, the focus shifted from proving that line capability varies to making DLR operationally actionable. Forecast ratings, filtering methods, uncertainty margins, operator displays, and integration with markets and security-constrained dispatch became central. Research also addressed complex terrain, computational fluid dynamics, short-term numerical weather prediction, probabilistic security assessment, and the correlation of DLR with renewable production.

In the 2020s, DLR became a prominent Grid-Enhancing Technology. FERC Order No. 881 required ambient-adjusted ratings for specified near-term uses, and FERC subsequently opened proceedings concerning potential DLR requirements and implementation criteria. At the same time, utilities and vendors expanded deployments using compact line-mounted sensors, cloud or edge analytics, higher-

resolution forecasts, and digital-twin concepts. The direction of travel is from isolated pilots toward repeatable, utility-grade rating services with formal data governance and operational procedures.

9.2.2 Thermal Rating Standards and Methods

IEEE Std 738 provides a numerical method relating the current and weather conditions of a bare overhead conductor to its core and surface temperatures under steady-state or time-varying conditions. The standard can also be used in reverse to calculate the current corresponding to a selected temperature limit. Importantly, IEEE 738 supplies a calculation method; it does not prescribe the weather conditions, conductor parameters, or risk criteria a utility should select for a rating. Those choices remain engineering and policy decisions.

CIGRE Technical Brochure 601 provides guidance for thermal-rating calculations, including dynamic methods that account for continuously changing weather. CIGRE publications also address selection of weather parameters and forecasting dynamic thermal ratings. In many practical applications, IEEE and CIGRE methods produce comparable conceptual results but may differ in detailed correlations, parameter treatments, and implementation conventions. A utility should select and document a consistent method, validate it against measurements, and avoid mixing assumptions without reconciliation.

The main model inputs include conductor diameter and construction, electrical resistance as a function of temperature, absorptivity, emissivity, heat capacity, maximum permissible temperature, line azimuth, elevation, ambient temperature, wind speed and direction, solar input, and time. For a facility rating, the calculation also requires knowledge of limiting spans, clearances, terminal equipment, and other series components. Good DLR practice therefore begins with an engineering model of the complete rated facility, not merely a vendor sensor installation.

9.2.3 DLR Measurement and Estimation Approaches

DLR systems are commonly classified as weather-based, asset-based, or hybrid as shown in Table 29. The classification describes what is directly measured and what is inferred through a thermal or mechanical model.

Weather-based systems may use dedicated line-corridor weather stations, public weather networks, remote sensing, or numerical weather prediction. Dedicated stations provide locally relevant observations but only at selected points. Numerical forecasts provide spatial coverage and future ratings, but their errors must be quantified, especially for low wind speeds and complex terrain. A robust system often blends observations and forecasts and applies conservative adjustments where the model is uncertain.

Table 29: Comparison of Dynamic Line Rating Measurement Approaches

Approach	How it works / advantage	Strength	Key limitation
Weather-based	Measures or forecasts ambient temperature, wind, solar conditions, and sometimes precipitation near the line. A thermal model calculates conductor temperature and ampacity.	No conductor-mounted hardware may be required; scalable across multiple spans when weather representation is adequate.	Wind at the critical span may differ from the measurement or forecast; requires careful spatial validation.
Conductor temperature	Directly measures conductor surface or internal temperature and uses current and thermal models to infer available margin.	Direct observation of the thermal state; useful for validation and asset awareness.	Light load can produce temperature changes within measurement uncertainty.
Sag or clearance	Measures sag, clearance, or conductor position using cameras, LiDAR, radar, or other methods.	Measures a key safety consequence of heating and mechanical loading.	Sag is influenced by tension, creep, ice, span geometry, and conductor history; conversion to ampacity requires a validated mechanical model.
Tension monitoring	Measures mechanical tension at structures and infers average conductor temperature or sag.	Can characterize a line section and may detect mechanical changes.	Requires accurate ruling-span and mechanical models; hardware installation and calibration can be significant.
Hybrid	Combines weather, electrical loading, direct measurements, and line models with quality checks or state estimation.	Provides redundancy, validation, and a more complete estimate; supports forecasting and diagnostics.	Highest integration and data-governance complexity; requires clear treatment of conflicting measurements.

Asset-based systems directly monitor the conductor or its mechanical response. Conductor-mounted devices may measure temperature, current, tilt, vibration, or local weather and communicate wirelessly. Sag or clearance systems observe the geometric consequence of temperature and loading. Tension systems infer average conductor state over a ruling span. Each method observes a different part of the physical process, and none removes the need to identify the true limiting span and terminal equipment.

Hybrid systems can use one measurement to validate another. For example, a weather-based model can predict conductor temperature while a conductor sensor checks the prediction. If the difference exceeds a threshold, the system can lower the published rating, flag maintenance, or revert to a fallback. This type of data fusion is increasingly associated with the term digital twin, although implementations vary and the label itself does not guarantee model quality.

9.2.4 System Architecture and Data Flow

A utility-grade DLR system normally contains five functional layers: (1) field or external data sources; (2) secure communications and time synchronization; (3) data-quality and state-estimation functions; (4) thermal-rating and forecasting algorithms; and (5) interfaces to operators, markets, EMS applications, and archives. The published rating is the result of the entire chain. A highly accurate sensor has limited operational value if communications, time stamps, model configuration, or EMS interfaces are unreliable.

Field data may include weather, conductor measurements, line current, breaker status, topology, and equipment availability. Data-quality checks screen for missing values, frozen sensors, implausible jumps, inconsistent units, stale time stamps, and disagreement between redundant sources. The calculation engine then determines conductor temperature or ampacity, applies the applicable facility cap, and may create several products: a real-time rating, a look-ahead rating, an emergency rating, and a conservative fallback.

The control-center interface should present not only the rating but also its validity and confidence. Operators need to know whether the value is measured, forecast, substituted, capped, or in fallback mode. Alarm thresholds, rating-change limits, and procedures should prevent rapid oscillation or unexplained jumps in an operational limit. Historical archiving is essential for model validation, post-event analysis, planning studies, and assessment of economic benefits.

A summary of the typical Dynamic Line Rating system architecture, including its principal functional components, representative elements, and primary control objectives, is presented in Table 30.

Table 30: Typical Dynamic Line Rating System Architecture, Data Flow, and Primary Control Objectives

Layer	Typical elements	Primary control objective
Data acquisition	Weather stations, conductor sensors, sag/tension devices, SCADA current, topology	Quality flags, time stamps, calibration status
Communications	Cellular, radio, fiber, utility networks, edge gateways	Encryption, redundancy, latency, cybersecurity, loss-of-signal behavior
Analytics	Thermal model, mechanical model, weather forecast, state estimation	Version control, parameter management, uncertainty treatment
Rating management	Equipment caps, filters, confidence margins, normal/emergency/	Clear hierarchy of limits and fail-safe behavior
Operational integration	EMS, state estimator, contingency analysis, market systems, displays	Update frequency, auditability, operator training, change management
Archive and review	Historian, event logs, model-performance reports	Benchmarking, maintenance, planning data, regulatory evidence

9.2.5 Rating Horizons and Operational Products

Real-time DLR is an estimate of present allowable loading based on the latest measurements. It is useful for situational awareness and real-time dispatch, but it cannot by itself support day-ahead scheduling or outage planning. Forecast DLR provides ratings for future intervals and must therefore include weather-forecast uncertainty. Forecast horizons may range from minutes to several days, with declining confidence at longer horizons.

A published operational rating may be lower than the raw calculated DLR. Utilities commonly apply confidence margins, percentile forecasts, equipment limits, minimum and maximum caps, persistence requirements, and limits on the rate of change. These controls reduce the risk that a noisy wind

measurement creates an unstable or impractical operating limit. The distinction between raw physical capability and the approved operational rating should be maintained in data archives and documentation.

Fallback ratings are fundamental. When critical sensors fail, forecasts are unavailable, communications are lost, or a model-quality flag is triggered, the system should automatically use a pre-approved conservative rating. The fallback may be the seasonal static rating, an ambient-adjusted rating, or another validated limit. The choice depends on the failure mode and the remaining trustworthy data.

9.2.6 Technology Maturity and Current Direction

DOE's 2019 Report to Congress concluded that DLR pilots and demonstrations had shown capacity increases but that results were difficult to extrapolate across lines and that technical, market, and regulatory challenges remained. Since then, the policy environment has advanced: FERC required ambient-adjusted ratings through Order No. 881 and initiated further proceedings focused on DLR implementation, including how wind, solar conditions, sensors, and weather forecasting should be considered.

The next stage of DLR is likely to emphasize integrated deployment rather than isolated lines; probabilistic and ensemble forecasting; integration with topology optimization, power-flow control, advanced conductors, and energy storage; and use of historical DLR data in planning. As deployment scales, governance will become as important as sensing: utilities will need standard asset models, approved assumptions, cyber controls, model-performance metrics, operator training, and transparent rules for when DLR can be credited in planning and operations.

9.3 Applications and Benefits

Dynamic Line Rating (DLR) is principally applied where the thermal capability of an overhead transmission line varies materially with weather and where that variability can be converted into operational or planning value. The technology does not increase the physical strength of a conductor or remove nonthermal constraints; rather, it provides a more accurate estimate of the current that the complete facility can safely carry under measured or forecast conditions. The resulting value depends on three factors occurring together: the conductor must be the governing constraint, favorable weather must coincide with system need, and operators or planning processes must be able to use the additional capability. When those conditions are present, DLR can improve utilization of existing corridors, reduce congestion and curtailment, facilitate new generation and load, and defer conventional upgrades.

The applications described below are not mutually exclusive. A single deployment may initially be justified as a congestion-relief measure, later provide outage flexibility, and ultimately supply historical data for planning studies. Table 31 summarizes the principal application areas and the mechanism through which DLR creates value. The magnitude of benefit remains corridor-specific and should be established using time-synchronized weather, loading, topology, and market data rather than a generic percentage uplift.

Table 31: Main applications of Dynamic Line Rating and associated value mechanisms

Application area	Value mechanism
Renewable integration	Uses favorable cooling conditions to increase transfer capability and reduce renewable curtailment when the constrained corridor and generation output are correlated.
Generator and large-load interconnection	Provides an additional alternative for accommodating new injections or withdrawals when thermal loading is the binding limitation.
Congestion and market operations	Improves the representation of available transfer capability, allowing lower-cost dispatch and reducing unnecessary redispatch or curtailment.
Outage and maintenance support	Provides temporary operating flexibility during planned outages, maintenance, construction, or abnormal topology, subject to forecast confidence and fallback procedures.
Technical, Operational, and Economic Benefits	Enhances transmission asset utilization through weather-responsive ratings, improving operational flexibility, supporting renewable integration, reducing congestion and infrastructure costs, and enabling more efficient and reliable grid operation.

9.3.1 Renewable Energy Integration

DLR is frequently associated with renewable integration because renewable resources are often located in remote areas where existing transmission corridors constrain delivery to load centers. When a line is thermally constrained, a weather-responsive rating can increase the amount of renewable output that can be accepted without exceeding the conductor-temperature limit. The application is especially attractive for wind generation because the same regional weather systems that increase wind production may also improve convective cooling of nearby conductors. This relationship can reduce curtailment and permit lower-cost generation to displace more expensive resources.

The correlation should not be assumed automatically. Wind speed at turbine hub height may differ significantly from wind at the critical line span, and congestion may occur at times when generation, local cooling, and system demand are not aligned. Solar generation presents a different profile: high solar output can coincide with strong solar heating and high ambient temperature, although local wind and seasonal conditions may still provide additional capability. For both wind and solar applications, benefits should be quantified using chronologically aligned generation, weather, line-rating, and dispatch data. DLR is most valuable when the additional rating occurs during the hours that would otherwise drive curtailment, redispatch, or an upgrade.

9.3.2 Generator and Large-Load Interconnections

For generator interconnections, Dynamic Line Rating (DLR) can increase the effective utilization of existing transmission corridors by identifying additional thermal capacity during favorable environmental conditions. This capability may reduce renewable energy curtailment, alleviate thermal congestion, and defer reconductoring or other transmission upgrades while longer-term network reinforcements are

planned and constructed. Similarly, for rapidly growing demand centers—including hyperscale data centers, electrified industrial facilities, and manufacturing expansions—DLR can provide valuable operational flexibility by supplying temporary transmission headroom during phased load growth or before permanent infrastructure becomes available.

The planning value of DLR, however, should be evaluated conservatively. Any planning credit should be supported by historical operating data, validated weather forecasts, and an assessment demonstrating that the required dynamic ratings are available with sufficient frequency and duration over the relevant study horizon. Utilities must also verify that the transmission facility is not constrained by terminal equipment ratings, protection systems, voltage or stability limits, or downstream network elements. Consequently, DLR should be regarded as a probabilistic enhancement to transmission capability rather than a source of unconditional firm capacity, unless its performance has been demonstrated through utility-specific engineering analyses and operational validation.

9.3.3 Congestion Management and Transfer Capability

Static or seasonal ratings can understate available transfer capability during many operating hours. When these ratings are used in security-constrained dispatch, the resulting constraint may force redispatch from low-cost generation to higher-cost generation, increase congestion components of locational marginal prices, or require renewable curtailment. A validated DLR allows the operator to use a more accurate thermal limit in real-time and look-ahead applications. FERC has emphasized that improved line-rating accuracy can both reveal additional capability and identify periods when transfer capability should be reduced for reliability.

The operational benefit depends on how the rating is incorporated into the Energy Management System, contingency analysis, and market or dispatch processes. A raw calculated ampacity is not automatically an operational rating. Equipment caps, confidence margins, persistence filters, ramp limits, and fallback logic may reduce the value published to the control room. Even after those adjustments, a modest increase on a frequently binding constraint can produce substantial economic value because it changes dispatch during high-cost congestion hours. Conversely, a large rating increase on a line that rarely binds may have little system benefit.

9.3.4 Outage Management, Reliability, and Asset Awareness

DLR can provide operational flexibility during planned outages, construction, maintenance, or abnormal topology. If an adjacent circuit is unavailable, a monitored line may safely carry additional current under favorable conditions, reducing the need for restrictive generation or load actions. Forecast DLR can also support outage scheduling by identifying weather windows with higher expected capability. These uses require greater attention to forecast uncertainty because the system may have fewer alternatives if the rating declines unexpectedly.

The data infrastructure installed for DLR can also improve situational awareness. Conductor temperature, sag, tension, local weather, and clearance measurements may reveal anomalous heating, icing, mechanical changes, sensor drift, or discrepancies in the line model. These observations can support model validation, post-event analysis, and condition-based maintenance. Such benefits are secondary to the line-rating function but can improve the overall business case, particularly when the same communications and analytics platform supports multiple asset-management objectives.

9.3.5 Technical, Operational, and Economic Benefits

The principal technical benefit of DLR is more accurate use of the conductor's weather-dependent thermal capability. This improves asset utilization without changing the underlying temperature, clearance, and equipment limits. It also improves the quality of operational information: the operator receives a rating that reflects current or expected conditions rather than a fixed seasonal assumption. In some hours, the dynamic value will be higher than the static rating; in adverse conditions it may be lower. The benefit is therefore accuracy and risk-informed utilization, not simply a permanent rating increase.

Operationally, DLR can increase transfer capability, reduce the frequency or severity of thermal constraints, improve outage flexibility, and provide additional response options during contingencies. It can also complement topology optimization, power-flow-control devices, advanced conductors, storage, and remedial action schemes. The combination can be more valuable than any individual technology: DLR identifies available thermal headroom, while another technology redirects flow toward that headroom. Coordination is essential because the limiting element can move as ratings and topology change.

Economic benefits arise when improved ratings change an actual decision. Avoided or deferred reconductoring and new-line construction can reduce near-term capital requirements and preserve optionality while load and generation forecasts develop. Operational savings may include lower congestion costs, reduced redispatch, lower renewable curtailment, and faster connection of generation or load.

Environmental benefits are primarily indirect. By enabling greater use of low-cost renewable generation and reducing curtailment or redispatch from higher-emitting units, DLR can support emissions reductions. It can also reduce the immediate need for new rights-of-way and make better use of existing corridors. These outcomes should not be counted automatically: the environmental value depends on the generation displaced, the duration of the additional transfer, and whether the deferred infrastructure is ultimately avoided or merely postponed.

In summary, DLR can provide substantial value for renewable integration, interconnections, congestion management, outage support, and planning. Its strongest business cases occur where a weather-dependent conductor limit is frequently binding and where the additional capability can be acted upon. The next sections of this framework address the technical and operational controls required to convert calculated ampacity into a secure utility operating practice.

9.4 Technical and Operational Considerations

The successful implementation of Dynamic Line Rating depends not only on the accuracy of the thermal rating calculation but also on a broad range of technical and operational considerations that determine whether the calculated rating can be applied safely and reliably in utility practice. These considerations include the quality and representativeness of weather and asset data, sensor selection and placement, communications, forecasting, data validation, equipment limitations, EMS integration, operator procedures, and governance. Together, these elements establish the engineering framework required to convert a calculated conductor ampacity into a secure operational transmission rating. The following sections discuss the principal technical and operational considerations that should be evaluated when planning, deploying, and operating DLR systems.

9.4.1 Facility Definition and Limiting-Element Assessment

The first technical requirement is to define the rated facility and identify the element that actually limits its transfer capability. Although DLR increases the weather-dependent thermal rating of an overhead conductor, the conductor is only one component of the rated transmission facility. Other series-connected equipment—including breakers, disconnect switches, current transformers, wave traps, jumpers, terminal conductors, and substation connections—may have lower continuous or emergency ratings than the conductor itself. Similarly, downstream facilities or adjacent network elements may impose additional restrictions on the permissible transfer. Consequently, the published operational rating should always be governed by the most restrictive validated equipment or facility limit rather than by the conductor ampacity alone.

In addition to equipment limitations, the governing transmission constraint may not be thermal at all. On many transmission corridors, interfaces, or long-distance power transfers, the maximum permissible transfer is determined by voltage performance, transient stability, angular stability, or other system-security criteria before the conductor reaches its thermal limit. In such cases, increasing the conductor ampacity through DLR does not necessarily increase the transfer capability of the corridor, because the binding constraint remains a system-level limitation rather than a conductor limitation. Therefore, DLR should always be evaluated within a comprehensive system assessment to ensure that any additional thermal capability can be utilized without violating voltage, stability, protection, or other operational security requirements.

The conductor model must represent the applicable conductor construction, diameter, resistance-temperature relationship, absorptivity, emissivity, heat capacity, maximum permissible temperature, span orientation, elevation, and mechanical-clearance criteria. Particular attention is required for the critical thermal span. Wind can vary significantly along a corridor because of terrain, vegetation, structures, elevation, and local channeling; the most weakly cooled span may not be located near a substation or a convenient weather station. Before operational use, the utility should confirm the critical span through engineering records, field surveys, sag-clearance analysis, LiDAR or other measurements, and comparison of calculated and observed conductor behavior. IEEE Std 738 provides the thermal calculation method,

but the utility remains responsible for selecting and documenting the facility parameters, allowable temperatures, and risk criteria used in the rating.

9.4.2 Weather Data, Forecasting, and Uncertainty

Ambient temperature, wind speed and direction, solar heating, and—in some implementations—cloud cover and precipitation are the principal weather inputs. Wind is generally the most influential and uncertain variable because convective cooling is highly sensitive to low wind speeds, wind angle relative to the conductor, turbulence, and local terrain. FERC's 2024 DLR proceeding specifically highlights wind, solar conditions, weather forecasting, and sensors as central implementation questions. The data source must therefore represent conditions at the line height and at the limiting spans, rather than merely using the nearest public airport or surface-weather station without validation.

Real-time observations support present-state ratings, whereas day-ahead and hour-ahead operations require forecast ratings. Forecast error should be characterized by horizon, season, location, and weather regime. A single deterministic forecast may be insufficient where a last-minute reduction in forecast wind would materially lower the rating. Utilities can address this risk through conservative percentile ratings, ensemble forecasts, confidence margins, persistence requirements, minimum-rating floors, and explicit procedures for forecast downgrades. Recent Idaho National Laboratory research illustrates the operational trade-off: increasing conservatism reduces the probability and severity of last-minute rating reductions, but it also reduces the capacity benefit available to operators. The appropriate margin should therefore be based on an approved risk tolerance and historical performance, not on an arbitrary percentage.

9.4.3 Sensing, Communications, and Data Quality

DLR may use corridor weather stations, conductor-mounted temperature or current sensors, sag or clearance monitoring, tension measurements, numerical weather prediction, or a hybrid of these methods. Sensor selection should follow the intended use. Weather-based systems can scale across many spans but depend on spatial representativeness. Direct conductor-temperature measurements provide valuable validation, although light loading may produce a temperature rise that is comparable to sensor uncertainty. Sag and tension systems observe mechanical response but require validated ruling-span and creep models. Hybrid systems can provide redundancy by comparing measured conductor state with a weather-based thermal model, but they also increase configuration and data-governance complexity.

The communications path is part of the rating system and should be engineered accordingly. Requirements include secure transport, accurate time synchronization, acceptable latency, redundant or diverse communications where justified, loss-of-signal detection, and defined behavior during partial data loss. Data-quality logic should detect missing or stale values, frozen sensors, implausible jumps, unit or sign errors, calibration drift, and disagreement between redundant sources. The system should retain quality flags and provenance so the control room can distinguish a measured value from a forecast, substituted input, calculated estimate, capped value, or fallback rating. DOE's review identified

communications, sensing, forecasting, system integration, and operational acceptance among the practical requirements and barriers associated with DLR implementation.

9.4.4 Rating Management and Fail-Safe Operation

The raw thermal ampacity should not be published directly to operators. Rating-management logic should apply the complete facility cap, forecast or measurement confidence margin, normal and emergency duration rules, filtering, and limits on the permitted rate of rating change. Filtering prevents sensor noise—especially short-lived wind fluctuations—from causing an unstable operating limit. A ramp-rate constraint limits abrupt changes in the published rating, but it must not delay a safety-critical reduction when validated conditions show that capability has fallen. Emergency ratings should be associated with a defined duration and transient conductor-temperature calculation; thermal inertia is not unlimited capacity.

Fallback logic defines the pre-approved action when DLR inputs or calculations become unavailable or unreliable. For example, failure of a critical wind sensor, loss of communications, expiration of a forecast, or a model-quality alarm may cause the system to use a validated Ambient-Adjusted Rating, seasonal Static Line Rating, or another conservative limit. The fallback should match the remaining trustworthy information and should occur automatically where practical. The system should also specify whether the last valid DLR may be held for a short grace period, how quickly loading must be reduced after a downgrade, and which alarms require operator acknowledgement. FERC Order No. 881 requires systems and procedures that can receive and use more accurate line ratings and underscores the need for transparent, electronically updated ratings in operational processes.

9.4.5 EMS Integration, Operating Procedures, and Human Factors

A utility-grade implementation should integrate DLR into the EMS, state estimator, contingency analysis, dispatcher displays, market or scheduling applications, historian, and—where appropriate—outage-planning tools. The displayed value should include its time horizon, effective interval, validity state, source, applicable facility cap, and fallback status. Operators should be able to determine why a rating changed and what action is required if a forecast rating is reduced. The EMS and downstream applications must also use consistent identifiers and units; an accurate rating is of little value if it is mapped to the wrong branch, applied to only one end of a facility, or not propagated to contingency analysis.

Procedures should address normal operation, forecast downgrades, contingencies, sensor or communications failures, maintenance outages, model changes, and restoration from fallback. Operator training is essential because DLR introduces a time-varying limit and may create additional workload during rapidly changing weather. Training should include the distinction between raw and approved ratings, the hierarchy of facility limits, the meaning of confidence and quality flags, and the actions required following a rating reduction. This aligns with the broader NERC expectations that transmission operators act promptly to prevent or mitigate reliability risks and that personnel supporting real-time operation receive training on topics essential to reliable performance.

9.4.6 Cybersecurity, Model Governance, and Performance Validation

Because DLR can influence operating limits and dispatch decisions, its sensors, gateways, communications, servers, interfaces, and configuration data should be included in the utility's applicable cybersecurity and change-management processes. Controls should address authentication, encryption, access privileges, patching, configuration baselines, vulnerability management, incident response, vendor remote access, and protection against the substitution or manipulation of weather and rating data. The applicable NERC Critical Infrastructure Protection obligations depend on system classification and architecture, but DLR design should follow the same core principle: unauthorized or unverified changes must not be allowed to alter a Bulk Electric System operating limit.

Model governance is equally important. Each facility should have controlled versions of conductor and equipment parameters, sensor locations, weather-source mappings, forecast models, confidence margins, fallback values, and approval records. Commissioning should compare calculated ratings and conductor-state estimates against field measurements over a representative range of load and weather conditions. Continuing performance review should evaluate forecast error, frequency and duration of fallback operation, sensor availability, rating volatility, false alarms, observed conductor temperature or sag, and instances in which forecast ratings were downgraded close to real time. Material model changes should be tested, documented, approved, and communicated to operators before production deployment.

9.4.7 Summary of Technical and Operational Considerations

The principal technical and operational considerations associated with the implementation of Dynamic Line Rating are summarized in Table 32, together with their primary engineering considerations and recommended operational controls.

Table 32: Summary of the Technical and Operational Considerations for Dynamic Line Rating

Area	Primary Consideration	Recommended Control
Facility rating	DLR may exceed another equipment or system limit.	Publish the most restrictive valid facility limit.
Voltage and stability limits	Verify that the transmission corridor is thermally, rather than voltage- or stability-constrained.	Perform system-wide power-flow and stability studies to identify the governing transfer limits
Weather and forecasting	Wind is spatially variable and forecast ratings are uncertain.	Validate siting; use confidence margins or probabilistic forecasts.
Sensors and data	Missing, stale, biased, or conflicting inputs can corrupt the rating.	Apply quality flags, redundancy, calibration, and provenance.
Communications and EMS	Ratings must reach all operational applications securely and on time.	Use secure interfaces, time synchronization, mapping checks, and alarms.
Rating management	Raw ampacity may be volatile or operationally impractical.	Apply caps, filters, ramp controls, duration rules, and equipment limits.
Failure response	Data or model failure can leave the operator without a valid DLR.	Automatically revert to a pre-approved conservative fallback rating.
Operations and governance	Changing limits affect operator workload and require controlled models.	Use procedures, training, version control, validation, and performance review.

9.5 Best Practices

Recent DLR experience shows a clear progression from instrumented demonstrations toward operational programs that influence dispatch, congestion management, renewable integration, and investment decisions. The strongest implementations are not defined only by the number of sensors installed or the maximum rating increase observed. They are distinguished by a well-defined operational objective, validated facility models, integration with control-room systems, conservative treatment of uncertainty, and evidence that the additional thermal capability can be used when the network needs it. The case studies below emphasize deployments from the United States first, followed by selected international programs, and identify the practical lessons that are most transferable to other utilities.

9.5.1 United States Deployment Experience

9.5.1.1 PPL Electric Utilities and PJM: Congestion Relief and Avoided Reconductoring

PPL Electric Utilities, working with PJM, deployed DLR on two Pennsylvania transmission lines to determine whether real-time ratings could manage congestion more economically than rebuilding the affected facilities. The operational intention was specific: provide PJM with line-condition information that could be used in dispatch and infrastructure decisions, rather than treat DLR as an isolated engineering pilot. PPL reported that the pilot demonstrated sufficient capability for PJM to conclude that a new or rebuilt line was not required to address the identified congestion. Subsequent DOE reporting attributes avoidance of an approximately \$12 million reconductoring project and more than \$64 million in congestion-cost reductions to DLR installations covering about 31 miles of line.

The project also illustrates the importance of evaluating the entire facility: if terminal equipment or another network element had become limiting, the observed conductor headroom would not have eliminated the upgrade. For other utilities, the transferable practice is to begin with a corridor that has recurring, measurable congestion and a clearly defined alternative investment, then establish in advance how the DLR output will be accepted by the system operator and reflected in operating or planning decisions.

9.5.1.2 National Grid, Western New York: Operational Ratings for Renewable Integration

National Grid installed non-contact monitoring systems on transmission lines in western New York to increase transfer capability and reduce curtailment of planned renewable generation. The project was announced in 2022 and became fully integrated into grid operations in 2024. National Grid and the technology provider described it as New York State's first operational DLR implementation and, at the time, the largest operationalized DLR project in the United States. The project was intended to avoid or defer rebuild costs while creating approximately 350 MW of additional capability for renewable delivery. National Grid has also reported that earlier implementations in New York and Massachusetts produced average transmission-capacity increases above 30 percent, although realized values remain line- and weather-specific.

This deployment provides two important lessons. First, a successful transition from trial to operation requires the rating to be visible, qualified, and actionable in the control room; a high-quality sensor output that remains outside the utility's operating systems has limited value. Second, non-contact monitoring can reduce installation complexity and conductor-mounted hardware, but the rating still depends on accurate line geometry, critical-span representation, forecast quality, and communications. The New York experience also supports phased deployment: demonstrate the method on a constrained corridor, complete EMS and operating-procedure integration, and then expand only after the utility has accumulated enough operating history to understand rating variability, alarms, fallback behavior, and maintenance needs.

9.5.1.3 Oncor, Texas: Capacity Increase under Hot-Weather Conditions

Oncor has used DLR sensors on selected Texas transmission facilities to obtain additional capacity in a system where high ambient temperatures and rapid load growth make static assumptions particularly consequential. DOE's 2025 summary reports capacity increases of approximately 6 to 14 percent across the evaluated applications and notes that the additional capability reduced the need for infrastructure investment. The intention was not merely to demonstrate that ratings vary with weather, but to quantify operationally dependable capacity under the climatic conditions of the ERCOT region.

The lesson is that DLR value should be assessed against local meteorology rather than transferred from another geography. Hot climates do not eliminate the DLR opportunity, because wind can still provide meaningful convective cooling, but low-wind and high-temperature periods can also reduce ratings.

9.5.1.4 AES Utilities, Indiana and Ohio: Multi-Line Evaluation across Diverse Grid Conditions

AES installed 42 non-contact DLR sensors on transmission structures in Indiana and Ohio in 2023, described by AES as the largest single U.S. deployment at that time. The program intentionally selected lines with different voltages, structures, terrain, and operating conditions so that the utility could evaluate where DLR produces repeatable value rather than optimize a single favorable site. AES framed the work as an assessment of how ATTs could safely maximize existing capacity, improve resilience, and support renewable integration. Public case-study material later reported an average capacity gain of 43 percent across evaluated conditions, project cost equal to approximately 7.6 percent of the reconductoring alternative, avoidance of roughly 2.5 months of outages, and about \$1.24 million in savings on one line; these values should be interpreted as project-specific rather than general expectations.

Deploying sensors across diverse facilities allowed AES to compare weather exposure, structural configuration, rating headroom, installation effort, and upgrade alternatives. The work also illustrates the schedule advantage of DLR: where reconductoring would require extended design, procurement, and outages, monitoring can sometimes be installed much faster. However, rapid installation does not remove the need for model validation, facility-rating review, or operating integration. A utility should use a multi-line demonstration to develop repeatable selection criteria, not merely to calculate an average uplift across unrelated circuits.

9.5.1.5 New York Power Authority: Correlation of Wind Production and Line Capability

NYPA's DOE-supported demonstration instrumented three 230 kV lines in northern New York to evaluate whether increased wind generation was correlated with increased transmission capability. The project used real-time thermal-rating measurements in areas with wind-development potential and examined whether DLR could defer capital expenditures. Although this demonstration predates the most recent operational deployments, it remains important because it tested one of DLR's central value propositions: favorable wind conditions may simultaneously increase renewable production and cool nearby conductors.

The principal lesson is that correlation must be demonstrated spatially and temporally. Wind at a turbine hub, wind at a public weather station, and wind at the critical transmission span are not interchangeable. A utility should align generation output, line loading, local weather, and the location of the limiting span before crediting synergy between wind generation and DLR. The project also reinforced the value of retaining high-resolution historical data, which later supports forecast validation, planning studies, and economic assessment.

9.5.2 International Deployment Experience

9.5.2.1 National Grid, Great Britain: From Trial to Network Rollout

National Grid Electricity Transmission moved from a 2022-2024 trial on a 275 kV circuit in northern England to installation across more than 275 km of overhead conductor in 2025. The stated purpose was to increase capacity across major north-south boundaries, integrate more renewable generation, and reduce constraint costs. National Grid estimated potential savings of approximately GBP 20 million per year for the 2025 deployment and reported that the technology could unlock capacity sufficient to serve about 75,000 homes. In 2026, National Grid announced a further 585 km rollout and reported that DLR had saved GBP 21 million in constraint costs over the preceding five years, with an average safe capacity increase of about 8 percent across the relevant circuits.

The central best practice is disciplined scaling. National Grid did not move directly from a small test to system-wide use; it accumulated multi-year trial evidence, integrated ratings with network operations, and expanded to boundaries where constraint costs created a measurable business case. The experience also shows that DLR is most effective as part of an integrated grid strategy. National Grid explicitly combines DLR with reconductoring and power-flow-control technologies, allowing one measure to expose headroom while another redirects power toward it. A related lesson is that national or regional control-room capability must scale with field deployment; the United Kingdom is implementing a ratings-management system so that real-time limits can be consistently received and applied by the system operator.

9.5.2.2 Statnett, Norway: Qualification, Forecasting, and Operational Learning

Statnett has followed a staged program that began with automatic ambient-temperature-adjusted ratings in 2018, continued with qualification of multiple DLR methods and sensor technologies, and progressed

to sensor-based DLR use in its eTerra control-center platform in 2023. Statnett reported that forecasts had been used operationally on three lines from June 2023, producing weekly average capacity increases that varied substantially by line and season and reached nearly 20 percent in some weeks. In 2026, Statnett began a broader sensor rollout, including drone installation and tower-mounted weather stations, with reported potential increases of up to 30 percent on selected lines.

Statnett's published experience provides unusually candid lessons. Testing sensors from three suppliers produced materially different ampacity estimates, demonstrating that vendor outputs should not be accepted without independent validation. Statnett also found that a weather-only method could become too optimistic because wind speed and direction are difficult to forecast and because the consequences of rating overestimation are asymmetric. The resulting best practices are to qualify technologies before fleet deployment, compare independent methods, use conservative uncertainty treatment, and continuously benchmark forecast ratings against sensor observations. Statnett's week-to-week variability also confirms that DLR should be viewed as time-varying capability, not a guaranteed percentage increase.

9.5.2.3 Red Electrica, Spain: Large-Scale Sensorization and Renewable Integration

Red Electrica announced in 2024 that it was deploying more than 750 DLR devices across selected overhead lines to maximize use of the Spanish transmission grid and facilitate renewable integration. The company reported that flows on certain lines could increase by up to 30 percent under favorable conditions. In the Balearic Islands, Red Electrica installed dense combinations of weather stations and conductor sensors on 66 kV lines to improve use of existing infrastructure, support renewable integration, and strengthen supply reliability in an island system.

The Spanish program demonstrates the importance of moving beyond a single-sensor concept. Dense monitoring is used where microclimate, island geography, mixed overhead-underground circuits, or supply-security concerns justify additional observability. The lesson is not that every span requires instrumentation, but that sensor density and placement should reflect terrain, exposure, line configuration, and the consequences of error. Red Electrica's public descriptions also emphasize communications and analytics as part of the solution, illustrating that large-scale DLR is fundamentally a data-governance and operational-integration program rather than a collection of field devices.

9.5.2.4 Elia, Belgium: Calibration and Real-Time Capacity Estimation

Elia uses DLR to estimate the maximum transmission capability of equipped lines in real time from local weather conditions and available measurement and forecasting techniques. Elia describes a process in which acquired data are used to calibrate the conductor model before variable transmission limits are produced. This approach highlights a foundational best practice: the thermal model should be calibrated to the actual asset and local environment rather than rely indefinitely on generic conductor parameters and remote weather observations.

9.5.3 Lessons from Recent Deployment Outcomes

A recurring lesson is that reported percentage increases are not directly comparable across projects. Some utilities report instantaneous or maximum uplift, others report weekly averages, and others report the operational rating after confidence margins and equipment caps. A high maximum value can coexist with modest annual economic benefit if congestion occurs at different times or if another facility becomes limiting. Best-practice reporting should therefore distinguish raw calculated ampacity, approved operational rating, average or percentile uplift, hours of binding congestion relieved, and monetized system benefit.

Recent deployments also demonstrate that forecast quality becomes more important as DLR moves from real-time awareness into day-ahead scheduling, outage planning, and market use. A real-time sensor can show present conductor behavior, but operators need a sufficiently conservative look-ahead rating to commit generation and manage contingencies. Forecast errors are asymmetric: under-forecasting sacrifices economic value, whereas over-forecasting can require urgent redispatch or threaten clearance and thermal limits. Utilities should therefore maintain confidence bands, conservative percentiles, rating-change controls, and documented remedial actions for forecast shortfalls.

A further lesson is that organizational readiness can govern the pace of deployment. Successful programs assign ownership for asset data, sensor maintenance, communications, forecast performance, EMS configuration, operating procedures, and post-event review. They also define who has authority to approve or withdraw a dynamic rating. Without this governance, DLR may remain an advisory display even when the underlying technology performs well. The transition from pilot to utility program should include acceptance tests, operator training, cybersecurity review, model version control, and recurring benefit verification.

Finally, DLR is most durable when treated as one option in a coordinated transmission strategy. Where thermal headroom is available but power does not naturally flow onto the monitored line, topology optimization or power-flow control may be required. Where ratings remain low during critical weather, reconductoring, storage, generation redispatch, or conventional expansion may still be necessary. The best-practice objective is not to maximize the use of DLR; it is to select the least-cost, reliable combination of measures for the specific constraint.

9.5.4 Cross-Cutting Best Practices and Lessons Learned

The recurring practices identified across the case studies are summarized in Table 33.

Table 33: Summary of Best Practices, Deployment Experience, and Recommended Utility Approaches for Dynamic Line Rating

Practice	Why It Matters	Evidence from Deployments	Recommended Utility Approach
Select a binding thermal constraint	DLR has little value where equipment, voltage, or stability limits govern.	PPL/PJM linked DLR to a specific congestion and rebuild decision.	Screen corridors using congestion history, facility limits, and system studies before deployment.
Integrate ratings into operations	Benefits occur only when ratings affect dispatch, outage, or market decisions.	National Grid New York and Statnett moved ratings into control-room platforms.	Define EMS interfaces, validity flags, alarms, fallback ratings, and operator procedures before go-live.
Validate sensors and models	Different technologies can produce materially different ratings.	Statnett observed significant deviations among three sensor suppliers.	Perform parallel testing, independent calculations, calibration, and periodic performance review.
Treat forecasts probabilistically	Wind uncertainty can create optimistic ratings and rapid reductions.	Statnett reported large seasonal and weekly variation and asymmetric risk.	Use conservative percentiles, confidence margins, look-ahead forecasts, and remedial-action capability.
Scale after operational proof	Large programs require governance, maintenance, and consistent rating management.	National Grid GB progressed from a two-year trial to hundreds of route-kilometers; Spain is deploying hundreds of devices.	Use staged deployment with documented acceptance criteria and post-implementation benefit tracking.
Combine DLR with complementary measures	Thermal headroom may not align with power-flow distribution.	National Grid combines DLR with reconductoring and power-flow controllers.	Evaluate DLR jointly with topology optimization, flow control, storage, and conventional upgrades.

9.6 Challenges and Barriers to Dynamic Line Rating

Dynamic Line Rating (DLR) is technically mature at the component level, but widespread utility adoption remains limited because successful deployment depends on more than the accuracy of the thermal calculation. The principal barriers arise from uncertainty in the availability and persistence of additional capacity, limited standardization of planning and operating practices, difficult integration with legacy utility systems, uneven economic incentives, and institutional reluctance to rely on weather-dependent limits for reliability-critical decisions. These barriers are distinct from routine implementation considerations: they determine whether a technically functional DLR system can be scaled, credited, financed, and trusted as part of normal utility practice. The following discussion summarizes the most significant challenges identified in recent DOE, FERC, INL, IRENA, and industry assessments.

9.6.1 Variability and Uncertainty

The additional capacity identified by DLR is inherently variable because it depends on local and forecast weather conditions. Wind speed and direction can change rapidly and may differ significantly among spans along the same corridor. As a result, a high average dynamic rating does not imply that the same capability will be available during the peak hour, under every contingency, or over the full planning horizon. This limits the amount of DLR capability that can be treated as firm transmission capacity. Recent international assessments characterize DLR as having relatively low firmness compared with reconductoring or new transmission because its contribution depends on favorable conditions, active system management, and probabilistic availability. Utilities must therefore avoid translating average or maximum DLR values directly into firm planning credit. The practical challenge is to develop defensible percentile, duration, and coincidence criteria that reflect the reliability need being studied.

9.6.2 Forecast Error and the Risk of Rating Reduction

A DLR forecast may degrade after generation, interchange, outage, or market schedules have already been established. This creates a distinct operational and commercial risk: the system may have to redispatch generation, curtail renewable output, reduce transfers, or activate remedial actions on short notice. More conservative forecasts reduce this risk but also reduce the usable value of DLR. Less conservative forecasts unlock more capacity but increase exposure to forecast error. FERC's 2024 DLR proceeding identifies weather forecasting, wind conditions, solar treatment, and sensors as central implementation questions, reflecting the fact that forecast quality and uncertainty treatment remain unresolved policy and engineering issues. The barrier is therefore not simply forecast accuracy; it is the absence of broadly accepted rules for converting forecast uncertainty into an operationally secure rating.

9.6.3 Legacy-System Integration and Lack of Standardization

DLR values must be accepted by Energy Management Systems, state estimators, contingency-analysis tools, market engines, outage-planning applications, and data historians. Many legacy systems were designed around a small number of fixed seasonal ratings and cannot readily manage hourly or sub-hourly

values, confidence indicators, changing emergency limits, or fallback states. Vendor interfaces, data models, update frequencies, quality flags, and naming conventions are not yet fully standardized across utilities and system operators. Consequently, a successful pilot may still require extensive custom engineering before it can be replicated across a fleet of lines.

9.6.4 Economic Incentives and Cost-Recovery Barriers

The DLR business case is highly corridor specific. Strong value may exist where a conductor is frequently congested and a conventional upgrade can be deferred, while the same technology may produce little economic benefit on an uncongested or non-thermal corridor. This uneven value complicates portfolio budgeting and makes outcomes difficult to extrapolate from one project to another. DLR also competes with conventional capital projects that often have established cost-recovery pathways and familiar utility accounting treatment. Digital optimization investments may face less certain recovery mechanisms even when their total system cost is lower. Hardware, communications, cybersecurity, software licensing, integration, and continuing maintenance costs must also be justified against benefits that may vary annually with congestion and weather.

9.6.5 Institutional Acceptance, Skills, and Long-Term Governance

DLR changes a line rating from a stable engineering value into a continuously managed operational product. This requires coordination among transmission planning, operations, asset management, information technology, cybersecurity, meteorology, market operations, and regulatory teams. Operators may reasonably be cautious about a rating that changes with weather or depends on remote sensors and third-party forecasting services. Pilot programs can demonstrate technical feasibility, but broad adoption requires training, clear authority, documented fallback rules, performance metrics, and confidence developed through operating experience. Long-term governance is equally important: sensors require inspection and calibration; models require parameter control and periodic validation; software and communications require lifecycle support; and archived results must be reviewed for bias or model drift. Without an enduring ownership model, a successful demonstration can remain an isolated pilot rather than becoming standard utility practice.

Conclusion

The collective analysis presented in this framework underscores the transformative potential of advanced transmission technologies in addressing critical challenges across the electric grid. From relieving thermal congestion and enhancing voltage stability to optimizing ROW utilization and enabling renewable interconnection, ATTs offer versatile and actionable solutions for modern grid operation and planning.

Indiana Utilities, like many utilities across the nation, faces complex constraints that cannot always be resolved through conventional transmission upgrades. The technologies examined—such as advanced conductors, APFC devices, and reactive power compensators—provide meaningful opportunities to enhance system performance without the extended lead times or capital burdens typically associated with traditional infrastructure expansion.

However, realizing the full value of these technologies requires a coordinated approach that integrates ATTs into Indiana Utilities' planning studies, protection schemes, operational practices, and interconnection assessments. This integration must also consider evolving regulatory expectations, such as those outlined by FERC, which increasingly promote the evaluation of innovative technologies as part of grid development efforts.

Ultimately, this framework advocates for a pragmatic, data-driven approach to ATT adoption—one that is informed by both technical merit and implementation experience. By leveraging the insights, modeling practices, and best-practice deployments outlined herein, IURC is well-positioned to lead in the deployment of high-impact, scalable, and resilient transmission solutions.

Appendix 1: Sample Modeling Files

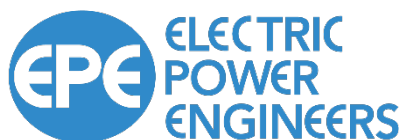
Sample Modeling	Sample Modeling Files
Advanced Power Flow Control	 Modeling_APFC.zip
Static Synchronous Compensators	 Modeling_STATCO M.zip
Static VAR Compensator	 Modeling_SVC.zip
Synchronous Condenser	 Modeling_Synchro nous Condenser.zip

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A low-angle, close-up photograph of a high-voltage electrical transmission tower. The image shows the complex lattice of steel beams and cross-arms supporting multiple high-voltage power lines. The perspective creates a sense of height and structural complexity, with the lines converging towards the top of the frame.

Advanced Transmission Technologies Procedure

**Decision Making,
Thermal Violations**

Presented To:

Indiana
Utility Regulatory
Commission



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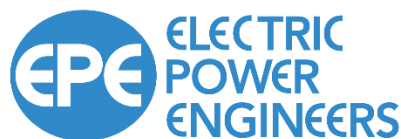
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1. Introduction

Advanced Transmission Technologies (ATTs) offer potential solutions that can be deployed more rapidly, cost-effectively, and with less disruption to the existing grid.

This document provides a systematic procedure for screening the feasibility of these technologies in addressing thermal overloads identified through system planning studies.

The methodology presented in this report is built around a structured decision-making framework, incorporating a set of technical features, rule-based evaluations, and decision trees. Figure 1 presents a high-level overview of the ATT feasibility evaluation process, which is detailed throughout this report. The process begins with violation identification and verification, followed by the development of traditional upgrade options. This step of procedure is considered as a generic study process which is well-established in existing transmission planning and generation interconnection workflow. Followed by generic study process, the ATT decision-making process introduces a structured screening framework that includes feature extraction and sequential evaluation of violation type, facility characteristics, contingency causes, and technology-specific considerations, as discussed in Section 3 and Section 4.

Upon identifying feasible ATT options, technology-specific guidelines are applied to support the development of preliminary justifications. These justifications are ultimately enhanced by comparative insights across technologies, as presented in Section 5.



Figure 1. Overview of the ATT Feasibility Evaluation Process for Thermal Violations

2. ATTs Feasibility Procedure

To support the integration of flexible, non-traditional transmission solutions, this section presents a step-by-step procedure for evaluating the feasibility of ATTs in response to identified system violations.

Figure 2 illustrates the overall ATT feasibility evaluation process. The procedure begins following the detection of a system violation and includes the following steps:

- **Violation Verification:** This step ensures the validity of the reported violation and serves as a foundational quality check before considering any mitigation options. The verification process may include but is not limited to confirming the accuracy of facility ratings, reviewing the definition and modeling of contingencies, validating assumptions used in the study case dispatch and base case setup. This verification step is a standard practice applicable to all transmission upgrade evaluations, whether or not ATTs are under consideration. Accordingly, this step is not part of the ATTs decision making process.
- **Feature Extraction:** To evaluate the feasibility of ATTs, key attributes of the identified violation must be extracted. These features, detailed in Section 3 of this document, serve as critical inputs to the ATTs decision-making trees. The features are selected based on industry best practices, subject matter experts (SMEs) input, and the technical characteristics of the technologies. The feature extraction process will be conducted by SMEs based on study results and engineering judgment.
- **Decision-Making Process:** A “**Rule-Based System**” has been developed to evaluate the feasibility of ATTs using extracted features of each violation. This system relies on a structured set of predefined “**if-then**” rules that assess the viability of various ATTs based on specific violation characteristics. These rules are derived from industry best practices, SME knowledge, and the inherent technical capabilities and limitations of the technologies. The decision-making framework serves as a screening process to identify where ATTs are not feasible or potentially feasible. The process is implemented using a set of compressed decision trees, which are detailed in Section 4 of this document.
- **If No ATT is Feasible:** Once “**Decision-Making Process**” determines that no ATTs are feasible for a specific violation, “**Infeasibility Rationale**” should be developed. This rationale should clearly address the central question: *Why are none of the ATTs feasible for this violation?* Section 4 of this document outlines common scenarios and technical conditions under which ATT solutions are deemed infeasible and can be used to guide the preparation of this rationale. Following this determination, the next step is to identify and evaluate traditional transmission upgrade options to resolve the violation.

-
- **If any ATTs might be Feasible:** Once “**Decision-Making Process**” indicates that one or more ATTs *might be* feasible for a specific violation, a “**Preliminary Feasibility Rationale**” should be prepared. This rationale must address the key question: *Why might an alternative solution be feasible for this violation?* It is important to note that this document does **not** constitute a full ATT feasibility study, which requires further technical evaluation and detailed analysis of the candidate technologies. Section 4 of this document outlines common scenarios and technical conditions under which ATT solutions might be feasible and can be used to guide the preparation of this documentation. In addition, relevant technical characteristics and considerations of ATT options may be incorporated into the rationale from the “**Alternative Transmission Technologies Framework**” document prepared by EPE.
 - **Technology Comparison for Deemed Feasible ATTs:** While the “**Decision-Making Process**” provides an initial feasibility rating (High, Medium, or Low) for each ATT option, a further comparative assessment on the deemed feasible technologies is necessary. This comparison should consider generic cost estimates, expected outage durations associated with implementing each technology, generic timeline of implementing each technology, and key technical considerations of each technology. The combination of feasibility ratings and technology comparison enables SMEs to prioritize and rank ATT options for more detailed feasibility studies. Section 5 of this document presents a comparative analysis of ATTs to support this evaluation.

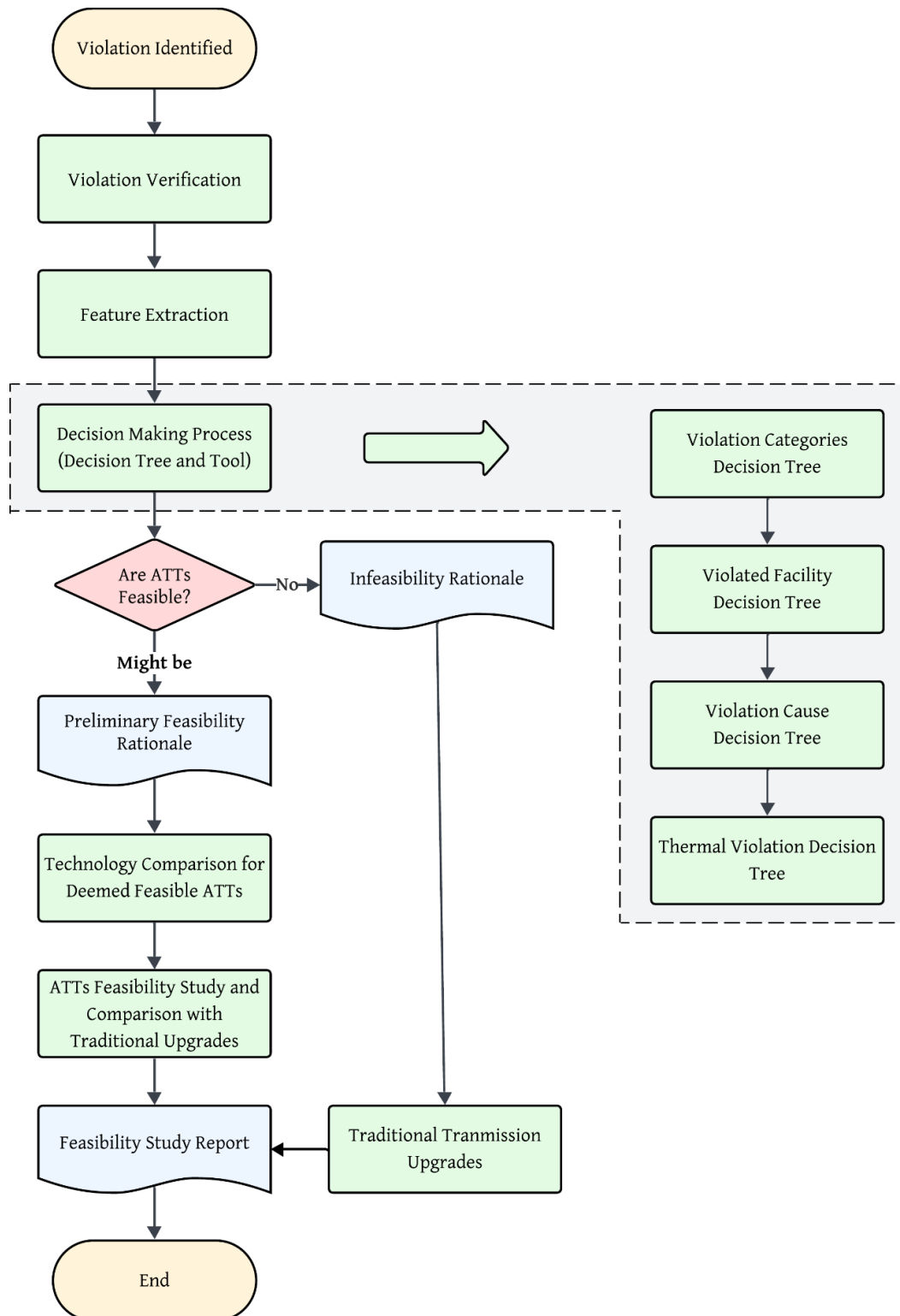


Figure 2. Flowchart for ATT Feasibility Assessment and Technology Selection

-
- **ATTs Feasibility Study and Comparison with Traditional Upgrades:** Following the ranking of ATT options, a detailed feasibility study must be conducted to evaluate each alternative's technical effectiveness and system impacts. This assessment should address two key questions: (1) *Can the ATT option successfully mitigate the identified violation?*, and (2) *Does the ATT option introduce any new violations or adverse impacts to the system?* To support this analysis, the modeling methodology presented in the **"Alternative Transmission Technologies Framework"** developed by EPE could be used to simulate and assess the performance of ATT solutions. Following the feasibility study, a comprehensive comparison should be conducted to evaluate the relative advantages and disadvantages of each ATT option against traditional transmission upgrades for the identified violation.

3. Decision-Making Factors

To enable effective screening, prioritization, and selection of mitigation strategies following system violations, this section defines a comprehensive set of decision-making factors, both quantitative and qualitative, that provide insight into the frequency, scope, drivers, and contextual relevance of each violation. These factors allow transmission planners to align potential solutions with technical feasibility, planning standards, and long-term system needs. A summary of these factors is provided in

Violation Frequency: This feature quantifies the total number of times a specific monitoring facility is overloaded across different base cases and under all evaluated contingencies. A high Violation Frequency highlights persistent vulnerabilities in the system, a.k.a., weak points, and may indicate locations where some ATTs are less practical in case of consistently high AC loading levels. This feature can be extracted from reliability assessment results in simulation tool.

Contingency Impact Scope: This feature represents the total number of monitoring facilities that experience an overload under an individual contingency scenario. This factor captures the extent of the impact caused by a contingency event, indicating how widespread the violation is across the system. A higher value suggests that the contingency affects multiple parts of the system, potentially might not be mitigated by ATTs. This feature can be extracted from reliability assessment results in simulation tool.

Facility Type: This feature identifies the type of facility where the violation occurs—typically a transmission line, transformer, or breaker. While the **Contingency Impact Scope** quantifies the extent of the violation across the system, the **Facility Type** highlights the diversity of affected equipment. The primary purpose of this feature is to consider the technical limitations of ATTs in addressing overloads on certain types of facilities. For example, ATTs are generally not directly applicable to transformers or breakers. This feature can be extracted directly from simulation tool.

Voltage Level: This feature classifies the voltage level of the overloaded facility. Within the Indiana Utilities footprint, voltage levels are categorized as follows:

- Medium Voltage (Sub-Transmission) (MV): < 100 kV
- High Voltage (HV): 100 kV – 345 kV
- Extra High Voltage (EHV): ≥ 345 kV

The purpose of this feature is to consider technical challenges and installation constraints associated with deploying ATTs at different voltage tiers. For example, installing Advanced Power Flow Control (APFC) equipment at EHV levels may be impractical due to stricter ground and phase-to-phase clearance requirements. This feature can be extracted from reliability assessment results in simulation tool.

AC% Loading: This feature represents the final AC loading percentage of a monitoring facility, based on its rated capacity under base case or post-contingency conditions. It reflects how heavily a facility is loaded relative to its limit. The purpose of this feature is to account for the limitations of ATTs in mitigating severe overloads. For instance, solutions like APFC or transmission switching may be less effective or infeasible when attempting to mitigate highly loaded facilities, potentially leading to new violations elsewhere in the system. This feature can be extracted from reliability assessment results in simulation tool.

DC% Loading: Similar to AC% Loading, this feature represents the final DC loading percentage of a monitoring facility, based on its rated capacity under base case or post-contingency conditions. The purpose of this feature is to compare AC and DC loading and extract additional information that can be utilized to classify violations in different categories. This feature can be extracted from reliability assessment results in simulation tool.

dLoading: This feature represents the absolute difference between AC% Loading and DC% Loading for a given monitoring facility, based on its rated capacity under base case or post-contingency conditions. The purpose of this feature is to help classify the nature of a violation whether it is primarily thermal, voltage-related, or a combined thermal and voltage issue. Larger discrepancies between AC and DC loading can indicate voltage-driven violations, whereas smaller differences suggest primarily thermal concerns. This metric can be derived from reliability assessment results produced by simulation tool.

MW% Loading: This feature represents active power (MW) loading percentage of a monitoring facility, based on its rated capacity under base case or post-contingency conditions. It indicates how heavily a facility is loaded by active power relative to its limit. This metric is used in conjunction with **dLoading** to help classify the nature of a violation whether it is thermal, voltage-related, or both. For example, if a facility is overloaded and its MW% Loading also exceeds 100%, thermal mitigation becomes necessary. In such cases, addressing the thermal overload may also resolve any associated voltage violations. However, reactive support alone is typically insufficient to mitigate both thermal and voltage issues. This feature can be extracted from reliability assessment results in simulation tool.

dMVAR Loading: This feature represents the absolute difference in reactive power (MVAR) flow between pre- and post-contingency conditions for a given monitoring facility. A larger change in MVAR loading typically indicates a voltage-driven violation resulting from the contingency. The purpose of this feature is to help classify the nature of a violation when used alongside **dLoading** and **MW% Loading**. For example, if a facility is overloaded but its MW% Loading is below 100%, thermal mitigation may not be necessary, especially if the observed dMVAR Loading can be addressed with additional reactive support. In such cases, reactive support may be sufficient to mitigate both thermal overload and voltage violations. This feature can be extracted from reliability assessment results in simulation tool.

ConType: This feature represents the contingency type, categorized according to NERC TPL-001-5 standards (P0 through P7 and Extreme Events). Since a monitoring facility may be overloaded under multiple contingency types, selecting the most relevant one requires judgment from SMEs in the context of generation interconnection or transmission planning standards. For example, a facility might experience overloads under P2, P3, and P6 contingencies. In such cases, one option is to select the contingency type associated with the worst-case loading, ensuring that the resulting mitigation strategy resolves all associated overloads. Alternatively, some overloads, such as those from P2 or P6 events, may be addressed through load drop, as allowed by the TPL-001-5 standard. In that case, the selected mitigation strategy may not eliminate all overloads but could still comply with planning requirements. This feature should be derived from reliability assessment outputs (e.g., simulation tool), guided by SME input and aligned with applicable standards.

Facility Location: This feature identifies whether a violated facility is located in vicinity of critical facilities or even plays a critical role in overall system reliability or operational constraints, which can significantly limit the feasibility of implementing certain mitigation strategies, such as transmission switching. A facility is flagged as having a critical role if it meets one or more of the following criteria:

- Located one or two buses away from a nuclear power station.
- Controlled by an existing Remedial Action Scheme (RAS).
- High impact on short-circuit strength or stability margins, making it sensitive to topology changes.
- Part of major transfer corridors, where changes may not be practical and could affect contractual power deliveries.

Facilities meeting any of these conditions should be excluded from transmission switching evaluations as well as strategies involving significant alterations to power flow paths. This feature can be derived from a combination of network topology, RAS documentation, and short-circuit/stability studies, supported by SME input.

Radial Index: This feature represents the radiality of a monitoring facility, that is, how dependent the facility is on a single transmission path in post-contingency condition. Facilities that serve load through only one transmission source are considered radial and are assigned a Radial Index of 1. The index ranges between 0 and 1, where:

- 1.0 indicates a fully radial path (no alternate routes).
- Values close to 1 suggest that while alternate paths exist, they carry minimal flow (low Distribution Factors or DFAX), implying limited operational flexibility.
- Lower values indicate that significant flow can be distributed across alternate paths, increasing the potential for mitigation via APFC or transmission switching.

As system topology changes due to contingency occurrence, the Radial Index is contingency-dependent. Therefore, selecting the most relevant value requires SMEs judgment considering planning criteria. The index can be computed in simulation tool.

Space Availability: This feature indicates whether sufficient physical space exists at the monitoring facility to accommodate the installation of alternative technologies. It serves as a key parameter in assessing the feasibility of equipment deployment, such as APFC. For example, deploying APFC on an overloaded transmission line only 0.5 miles in length may be technically infeasible if adequate space is not available. Space availability can typically be determined from facility layout drawings or site surveys.

Limiting Element: This feature identifies the limiting element that determines the thermal or operational rating of a monitoring facility. For a given transmission line, the limiting component may be the conductor size, disconnect switch, jumper, wave trap, or ground clearance. Understanding the limiting element is essential for assessing the feasibility of alternative solutions. For example, if the rating is limited by components such as disconnect switches, jumpers, or wave traps, most ATTs will not be applicable. While if ground clearance is the constraint, then tower lifting may be a viable mitigation strategy. This feature supports solution screening and prioritization.

Load Impact (Applicable to Annual TPL Study): This feature represents the impact of load on a monitoring facility under contingency conditions. It identifies whether load growth, local area or at specific substations, aggravates (harms) or alleviates (helps) the loading on the facility, depending on how the power flows are redistributed post-contingency. Technically, the Load Impact reflects whether load growth in the vicinity of a facility contributes to additional stress on that facility, or not. Because system topology changes during contingencies, this effect is contingency-dependent. It is also substation-dependent, as different substations have different load distribution factors and injection sensitivities relative to the monitoring facility. For planning purposes, the worst-case load impact should be used to support conservative and robust mitigation strategies. This feature is particularly useful in annual TPL reliability assessments, where load growth projections play a key role in evaluating system adequacy. The Load Impact metric can be calculated using simulation tool by evaluating facility-substation pairs across relevant contingency scenarios.

Load Growth (Applicable to Annual TPL Study): This feature quantifies the anticipated load growth in neighboring substations, based on forecasted demand projections that are not yet reflected in the base cases under study. It serves as a forward-looking adjustment to better align reliability assessments with future system conditions. When combined with the Load Impact feature, Load Growth helps estimate additional/less loading on a monitoring facility under contingency scenarios. This combined estimate can be used to augment the AC% Loading to capture potential future stress that may not be evident in current base case models. Unlike Load Impact, Load Growth is a system-independent input, derived from planning forecasts. This feature is particularly useful in annual TPL reliability assessments, where Load Growth projections play a key role in evaluating system adequacy.

Generation Impact (Applicable to Annual TPL Study): Similar to Load Impact, this feature represents the impact of generation on a monitoring facility under contingency conditions. It identifies whether generation growth—local area or at specific substations—aggravates (harms) or alleviates (helps) the loading on the facility, depending on how the power flows are redistributed post-contingency. Technically, the Generation Impact reflects whether Generation growth in the vicinity of a facility contributes to

additional stress on that facility, or not. Because system topology changes during contingencies, this effect is contingency-dependent. It is also substation-dependent, as different substations have different DFAX. For planning purposes, the worst-case Generation Impact should be used to support conservative and robust mitigation strategies. This feature is particularly useful in generation interconnection reliability assessments, where generation growth projections play a key role in evaluating generation deliverability. The Generation Impact metric can be calculated using simulation tool by evaluating facility-substation pairs across relevant contingency scenarios.

Generation Growth (Applicable to Annual TPL Study): This feature quantifies the anticipated generation growth in neighboring substations, based on generation interconnection request projections that are not yet reflected in the base cases under study. It serves as a forward-looking adjustment to better align reliability assessments with future system conditions. When combined with the Generation Impact feature, Generation Growth helps estimate additional/less loading on a monitoring facility under contingency scenarios. This combined estimate can be used to augment the AC% Loading to capture potential future stress that may not be evident in current base case models. Unlike Generation Impact, Generation Growth is a system-independent input, derived from interconnection requests. This feature is particularly useful in generation interconnection reliability assessments, where Generation Growth projections play a key role in evaluating generation deliverability.

Table 1. Feature Set Used for ATT Feasibility Assessment

Feature	Description
Violation Frequency	Number of times a facility is overloaded across all base cases and contingencies.
Contingency Impact Scope	The total number of facilities overloaded under a single contingency scenario.
Facility Type	Violated facility type, transmission line, transformer, breaker.
Voltage Level	Classification of the overloaded facility's voltage level (MV, HV, EHV).
AC% Loading	Final AC loading percentage of a facility in base case or post-contingency.
DC% Loading	Final DC loading percentage of a facility in base case or post-contingency.
dLoading	Absolute difference between AC and DC loading percentages.
MW % Loading	Final MW loading percentage of a facility in base case or post-contingency.
dMVAR Loading	Absolute difference between pre- and post-contingency MVAR flows.
ConType	Type of contingency, categorized per NERC TPL-001-5 (P0–P7).
Facility Location	Indicates whether a violated facility is critical or nearby critical facilities.
Radial Index	Degree to which a facility is radial, ranging from 0 (non-radial) to 1 (fully radial).
Space Availability	Physical space availability at monitoring facility to accommodate the installation
Limiting Element	Thermal rating limiting element of a facility (e.g., conductor, wave trap, clearance).
Load Impact	Effect of load growth on a facility under contingency conditions.
Load Growth	Projected increase in load at nearby substations.
Generation Impact	Effect of generation growth on a facility under contingency conditions.
Generation Growth	Projected increase in generation at nearby substations.

4. ATTs Decision-Making Process for Thermal Violations

To systematically evaluate the feasibility and selection of ATTs in response to thermal violations, this section presents a comprehensive decision-making framework. At its core is **a rule-based system** built on predefined “**if-then**” logic that assesses the viability of ATT solutions based on key features extracted from each violation. These rules are grounded in industry best practices, SME experience, and the known technical capabilities and constraints of each technology.

The section consists of three integrated components. Section 4.1 introduces the ATT Feasibility Screening Logic, where a sequence of high-level decision trees, including violation category, facility type, and contingency cause, helps determine whether any ATT solutions are potentially viable. Upon ATTs feasibility evaluation, Section 4.2 outlines technology-specific implementation guidelines for four key solutions: advanced conductors, tower lifting, APFC, transmission switching, and Dynamic Line Rating (DLR). Finally, Section 4.3 presents a technology selection decision tree, summarizing the implementation criteria and aiding in comparative selection among feasible ATT options.

4.1. ATT Feasibility Screening Logic

This subsection introduces the initial screening process to determine whether ATTs are potentially viable for a given thermal violation. Based on stakeholder responses from the Indiana utilities, early screening of ATT applicability is an important step to rule out infeasible alternatives before proceeding with technology-specific evaluations. The initial screening consists of three structured decision trees that evaluate the nature of the violation, the type of affected facility, and the underlying contingency cause. Together, these trees form a logical pathway for ruling out infeasible cases and advancing only applicable scenarios to detailed technology evaluation.

4.1.1. Violation Categories Decision Tree

The nature of system violations can generally be classified as thermal, voltage-related, or a combination of both. The features **dLoading**, **MW% Loading**, and **dMVAR Loading** (refer to Table 1) serve as key indicators for identifying the violation type and determining appropriate mitigation strategies.

As described in Section 3, dLoading reflects reactive power flow on the monitored facility, which is typically associated with voltage violations. A high dLoading value suggests that voltage issues are contributing to the observed overload. Meanwhile, MW% Loading indicates the extent to which the facility is overloaded due to active power (MW) flow.

For instance, if a monitoring facility shows high dLoading and MW% Loading above 100%, thermal mitigation is required regardless of the voltage violation. In these cases, resolving thermal overload may also address any voltage-related issues. Conversely, if MW% Loading is below 100%, thermal mitigation

may not be necessary, especially if the observed dMVAR Loading can be mitigated through reactive power support. In such scenarios, voltage violations may be addressed solely with reactive support, avoiding the need for thermal upgrades.

Figure 3 outlines the decision tree used to determine the violation category.

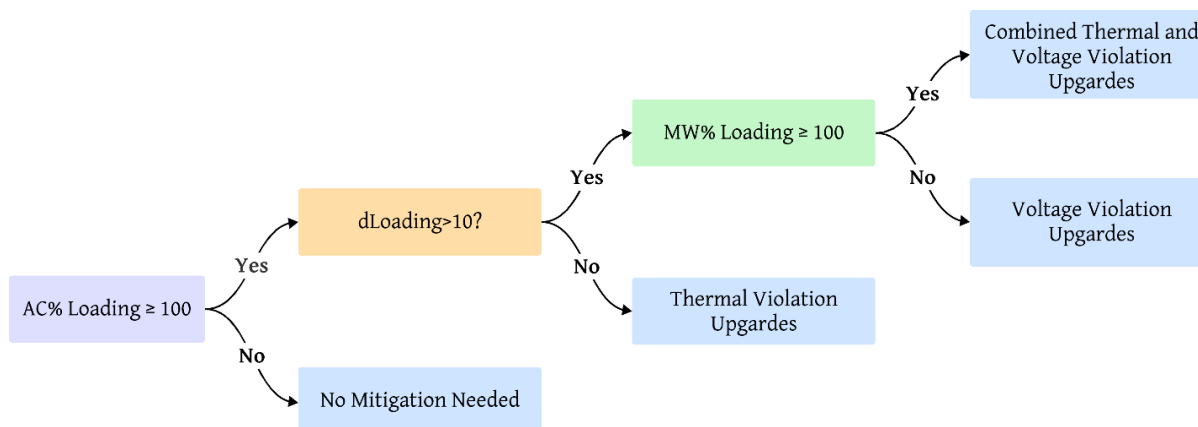


Figure 3. Decision Tree for Classifying Violation Type

4.1.2. Violated Facility Type Decision Tree

System violations may occur across a variety of facility types, including transmission lines, transformers, breakers, and other equipment such as jumpers and wave traps. In some cases, a single violation may involve a combination of these elements. The practicality of implementing ATTs depends significantly on the type of violated facility and equipment involved. Below is a summary of common facility types and considerations for ATT feasibility:

- **Transmission Lines:** When a transmission line is overloaded, ATTs may be feasible depending on two key factors: the physical length of the line and the limiting element that defines its rating. For example, if the limiting element is a jumper, ATTs are typically not viable. Similarly, for short transmission lines, solutions such as APFC may not be technically or economically justified.
- **Transformer:** If a transformer is overloaded under a contingency with a limited **Contingency Impact Scope** (i.e., the violation is limited to the transformer itself), ATTs are generally not practical compared to conventional upgrades. However, in situations where a transformer upgrade has a long lead time, temporary ATT deployment (e.g., rerouting flow) may be considered, requiring SMEs' judgment.
- **Breaker and Disconnect:** Similar to transformers, these elements offer little opportunity for ATT deployment when the violation is limited solely to the equipment. Traditional equipment upgrades are usually the only viable option.
- **Mixture of overloaded facilities:** When a contingency causes violations across a combination of facilities and equipment including transmission line, i.e., a broad **Contingency Impact Scope** and

Facility Type, certain ATTs may become viable and should be evaluated further. In most of this scenario, the mitigation plans that involve rerouting flow to resolve transmission line violation might resolve the issues for the rest of the equipment as well.

This decision logic is guided by key features outlined in Section 3, particularly Contingency Impact Scope, Facility Type, and Limiting Element. The output of this decision logic describes whether ATTs are practical or not. For example, if a transmission line is overloaded under a contingency with no other affected facilities, the ATT feasibility primarily depends on the limiting element. In contrast, if multiple transmission lines are overloaded, further SME evaluation is needed to determine whether the violations are on the same corridor, which influences ATT applicability.

In another scenario, if single facility or multiple facilities are overloaded with no transmission line overloads, such as overloaded transformers and breakers, ATTs are typically not practical compared to conventional equipment upgrades. On the other hand, if transformers and breakers are overloaded along with a transmission line, ATTs might be feasible depending on Limiting Element. In this scenario, if the rating is limited by components such as disconnect switches, jumpers, or wave traps, ATTs are generally not applicable. If the limiting factor is conductor size or ground clearance, ATTs (e.g., reconductoring, tower lifting) may be feasible.

This decision tree is designed solely to assess ATT feasibility based on facility type. If ATTs are deemed feasible, further analysis is required to identify and prioritize specific technologies, as discussed in the next sections. Figure 4 outlines the decision tree used for evaluating the feasibility of ATTs.

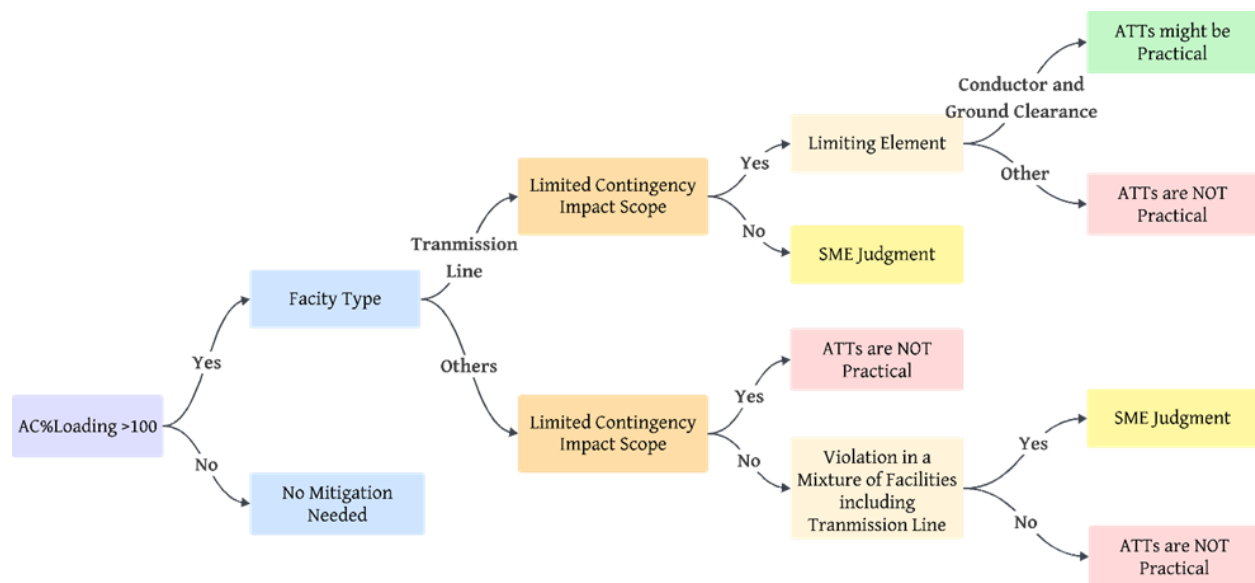


Figure 4. Decision Tree for Assessing ATT Feasibility Based on Violated Facility Type

4.1.3. Violation Cause Decision Tree

System overloads may cause from various types of contingencies, as categorized under NERC TPL-001-5 standards (P0 through P7 and extreme events). The feasibility of ATTs highly depends on the nature and classification of these contingencies.

It is important to note that this section does not evaluate the accuracy or legitimacy of contingency definitions. Rather, it assumes that all provided contingencies are valid and any resulting violations are credible. For example, certain contingencies may appear to cause reverse power flow and overload downstream facilities. However, in practice, reverse relays would typically trip the associated transformers, preventing the overload. This scenario is not considered here; the analysis focuses solely on ATT feasibility under the assumption that each contingency is properly defined.

ATTs are generally not practical for base case violations (P0), where system upgrades are typically expected. Similarly, for certain contingencies like P5 events, the preferred approach is often to eliminate the contingency altogether, such as by upgrading redundant protection systems. In these cases, ATTs are also not considered practical. Furthermore, the TPL-001-5 standard allows for some overloads to be mitigated through load shedding, depending on the contingency type and the voltage level of the overloaded facility (e.g., HV or EHV). These situations require careful judgment from SMEs to determine whether a non-infrastructure alternative (e.g., load drop) is appropriate or if a system upgrade is necessary.

It is important to note that a facility may be overloaded under multiple contingency types (i.e., **Violation Frequency** > 1). In such cases, selecting a representative contingency type (**ConType**) for mitigation planning requires SME input. For example, if a facility is overloaded under P2, P3, and P6 events, one approach is to select the contingency that results in the worst-case loading, thereby ensuring that the mitigation resolves all associated overloads. Alternatively, if overloads from P2 or P6 events can be mitigated by load drop as permitted under TPL-001-5, the selected strategy may not address all overloads, but could still remain compliant with planning standards.

This logic is intended specifically for evaluating the feasibility of ATTs based on the violation cause. If determined to be feasible, further analysis will be required to evaluate and prioritize specific technologies, as detailed in the subsequent sections. Figure 5 presents the decision tree used to assess ATT feasibility based on the underlying violation cause.

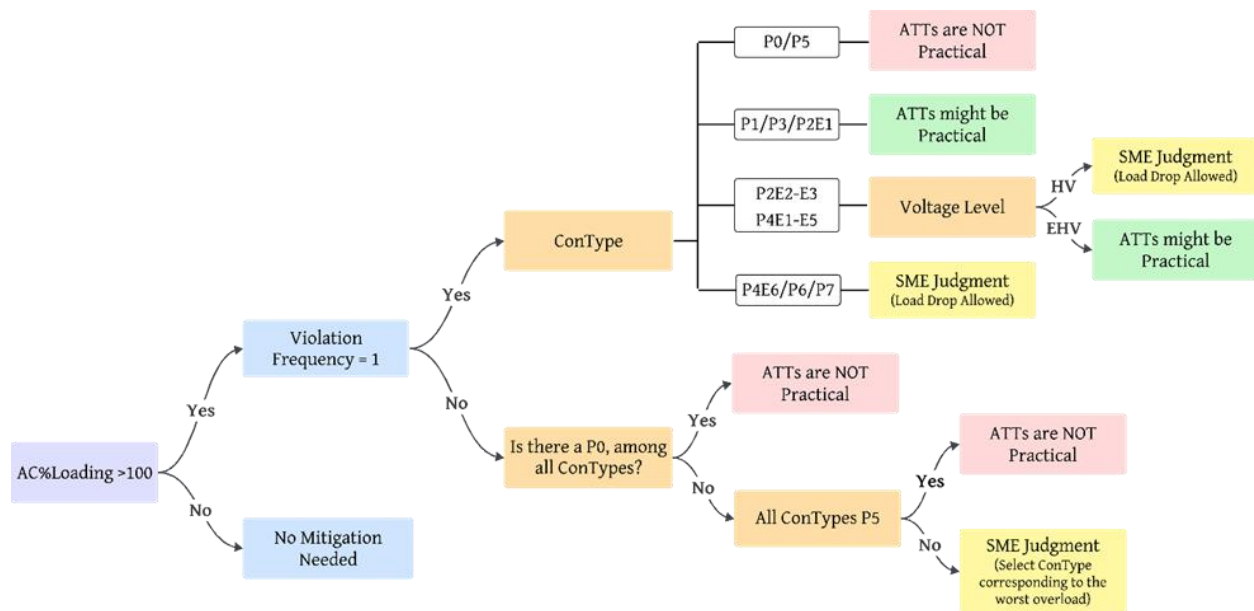


Figure 5. Decision Tree for ATT Feasibility Based on Contingency Type (Violation Cause)

4.2. ATT Implementation Guidelines

This section outlines key considerations and technical criteria for deploying specific ATTs once their feasibility has been established. These implementation guidelines serve not only as a reference for evaluating deployment practicality, but also as a structured basis for documenting both infeasibility justifications and preliminary feasibility rationales in planning reports. Each subsection provides focused insights into when and how each technology may be effectively applied.

4.2.1. Advanced Conductor Implementation Feasibility Guidelines

Generally, transmission planning projects that implement advanced conductors¹ can be categorized into three groups: reconductoring with minimal tower upgrades, rebuild projects with major tower upgrades, and new transmission line projects.

Based on input received from Indiana Utilities SMEs during stakeholder meetings, advanced conductors are being actively considered as a transmission upgrade strategy to address reliability concerns within the Indiana Utilities footprint.

Once a violation is identified, that is categorized as a thermal violation per violation category decision tree in Figure 3, and ATTs are deemed feasible per decision trees in Figure 4 and Figure 5, advanced conductors are typically considered a benchmark mitigation option in the following scenarios:

¹ Technology details and best practices are discussed in Section 1 of “Alternative Transmission Technologies Framework”.

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- Advanced conductors might be a practical alternative to conventional upgrades if the overloaded line loading is less than 150%² of line rating, which is based on best practice implementations as well as typical range of additional ampacity provided by advanced conductors with similar weight. In this scenario, the tower upgrades might not be necessary and there would be no need for rights-of-way (RoW) expansion, which should be verified by the design team. Once the overload is between 150% to 250%, advanced conductors might be a feasible alternative solution as well, while in most cases require tower upgrades as well as minimal RoW expansion. Finally, once overload is larger than 250%, typically a new transmission line might be necessary which could be reinforced with advanced conductors.
 - Advanced conductors are typically considered as a practical alternative when the limiting element of line rating is conductor size. In addition, when the limiting element of line rating is ground clearance, advanced conductors with their low-sag characteristics may offer a practical alternative to tower lifting. Also, in scenarios to achieve long spans, especially over rivers with restricted in-river structures, advanced conductors might be an alternative solution for tower lifting solution. Additionally, advanced conductors might be preferred over tower lifting in areas with extreme weather conditions, such as high wind and ice loading, or where tower heights is restricted by aviation authorities.
 - According to best practices, advanced conductors are used across all voltage levels (MV, HV, EHV), but the intensity of their adoption and the purpose vary by level. At the MV level (<100 kV), their implementation is generally limited to areas with space constraints or elevated thermal demands, due to cost considerations. At the HV level (100–299 kV), advanced conductors are more commonly adopted to increase power transfer capacity without expanding RoW. At the EHV level (≥300 kV), they are widely used for new transmission projects.

Table 2 summarizes key features influencing the feasibility of advanced conductor implementation.

Despite the benefits of advanced conductors, lack of conductor test data limits their widespread adoption. Testing advanced conductors presents significant challenges that impede their widespread adoption. This is primarily due to the complexity, duration of required evaluations and in some cases unavailability of pre-existing test data as compared to the conventional conductor.

Advanced conductor implementation is considered a non-simulation and non-controlled solution, meaning that once it is determined to be a practical and feasible option by the engineering and design team during the planning process, no additional power flow or dynamic simulations are required. This contrasts with certain controlled ATTs, such as APFC, which may necessitate system modeling and stability verification.

² For ACSS, increased capacity is less than 25% of line rating, i.e., 125% AC% loading.

Table 2. Key Factors Influencing the Feasibility of Advanced Conductor Implementation

Key Feature	Feasibility Impact
Facility Type	Advanced conductor is viable if the overloaded facility is transmission line
Voltage Level	Applicable across all voltage levels; most common at HV for capacity expansion, and at EHV for new builds; limited at MV due to cost.
AC% Loading	Determines feasibility, overloads less than 150% likely feasible with minimal upgrades; 150–250% may require tower/RoW upgrades; overloads above 250% often requires new transmission line.
Limiting Element	If conductor size limits line rating, advanced conductors may be ideal; if ground clearance is limiting, low-sag characteristic of advanced conductors can be an alternative to tower lifting.

4.2.2. Tower Lifting Implementation Feasibility Guidelines

One of the primary thermal limitations in overhead power transmission is conductor sag, which increases as conductor temperature rises during peak load or elevated ambient conditions. As a result, the allowable thermal loading of a line might often be restricted by the minimum required clearance between the conductor and ground or underlying infrastructure. Tower lifting³ directly addresses this constraint by physically increasing the height of existing transmission structures, thereby improving conductor ground clearance. Tower lifting directly addresses this constraint by physically increasing the height of existing transmission structures, thereby restoring or improving conductor ground clearance. By elevating specific towers along a line segment, system operators can safely accommodate higher conductor operating temperatures and greater current flow without breaching clearance standards.

Based on feedback received from Indiana Utilities SMEs during stakeholder meetings, tower lifting is recognized as an established and viable mitigation strategy for addressing thermal violations within the Indiana transmission system. This suggests the existence of internal standards and experience supporting the deployment of tower lifting measures.

Once a violation is identified, that is categorized as a thermal violation per violation category decision tree in Figure 3, and ATTs are deemed feasible per decision trees in Figure 4 and Figure 5, tower lifting should be considered as a possible alternative in the following scenarios:

- Tower lifting is often the preferred alternative to traditional reconductoring when the line rating is limited primarily by inadequate ground clearance, rather than by conductor size. This is especially effective when line loading remains below approximately 150% of the existing rating. Engineering studies, including clearance assessment and structure modeling, are necessary to identify which specific towers require elevation.

³ Technology details and best practices are discussed in Section 4 of “Alternative Transmission Technologies Framework”.

- In cases where conductor size is the primary limiting element of line rating, but existing ground clearance cannot accommodate advanced conductors with higher ampacity, a combined solution involving tower lifting and advanced conductor replacement may be appropriate. This approach can support loadings up to 250% of the original line rating, assuming both sag and tension constraints are addressed. Careful coordination of structural integrity, conductor mechanical properties (e.g., tension, creep, sag), and tower design are essential to ensure feasibility.
- Industry’s best practices suggest that tower lifting is generally more feasible and effective on HV and EHV lines due to greater structural clearances, mechanical robustness, and economic justification. Tower lifting was typically not implemented for MV lines, except in special cases, due to limitations on the height of structures and the cost-benefit tradeoffs.

Table 3 summarizes key features influencing the feasibility of tower lifting implementation.

Tower lifting is categorized as a non-simulation, non-controlled solution, meaning that once it is deemed feasible by the engineering and design team, no further power flow or dynamic simulations are required to validate its effect. This makes it operationally simpler compared to controlled ATTs, such as APFC devices, which typically require extensive system modeling, transient stability assessments, and protection coordination studies. Moreover, tower lifting can often be implemented with minimal outage durations by utilizing structure extensions, mobile lifting devices, or temporary support towers during construction.

Table 3. Key Factors Influencing the Feasibility of Tower Lifting Implementation

Key Feature	Feasibility Impact
Facility Type	Tower lifting is only applicable to overhead transmission lines.
Voltage Level	Most feasible for HV and EHV lines due to structural capacity and clearance; rarely used for MV lines due to limited tower height and cost-effectiveness.
AC% Loading	Most viable when loading is $\leq 150\%$ of rating; loadings up to $\sim 250\%$ may be feasible with combined tower lifting and advanced conductors; beyond that, new line likely required.
Limiting Element	Tower lifting is viable when ground clearance limits line rating; also may be combined with advanced conductors when conductor ampacity is the limiting factor and clearance is insufficient.

4.2.3. Advanced Power Flow Control Implementation Feasibility Guidelines

APFC devices enable more efficient utilization of existing transmission infrastructure by dynamically redirecting power flows away from overloaded elements and toward underutilized corridors. By reshaping real-time power flows, APFC⁴ systems can increase transfer capacity into constrained areas, such as dense urban load pockets, without requiring new transmission lines or major infrastructure investments. These devices are modular, scalable, and flexible, making them well suited for staged deployments that address near-term reliability needs while supporting long-term grid expansion strategies.

Once a violation is identified, and categorized as a thermal violation per violation category decision tree in Figure 3, and ATTs are deemed feasible per decision trees in Figure 4 and Figure 5, APFCs should be considered as a possible alternative in the following scenarios:

- APFC is only viable if the overloaded facility is not in a radial corridor in post-contingency condition, otherwise there would be no alternative corridor to reroute flow away from the overloaded facility to the unutilized corridor. Accordingly, non-radiality is a necessary, but not sufficient condition for feasibility of APFC. APFC deployment in a radial path would have no rerouting capability and is equivalent to load shedding or generation curtailment, thus considered infeasible
- APFC deployment is only viable if the alternative corridors can absorb the redirected power without exceeding their own thermal limits. Thus, APFCs are only feasible when they do not introduce secondary overloads in the system.
- Once multiple facilities are overloaded due to a contingency occurrence, APFCs might be a feasible solution if overloaded facilities all belong to the same corridor. Otherwise, separate mitigation strategies should be established to address each corridor's overload, where APFCs might not be the most effective alternative solution since mitigating overload in one corridor might inadvertently worsen conditions in another.
- APFCs might be a practical alternative to traditional transmission upgrades, where the overloaded facility is operating at 140–150% of its rated thermal capacity. Clearly, the lower the degree of overload, the greater the likelihood of APFC feasibility. Beyond this threshold, multiple APFC units may be necessary, which could compromise cost-effectiveness and operational practicality. Note that this threshold could be derived from limitations on hosting capacity of the alternative corridor and number of APFC devices needed to redirect power flow, where both limitations depend on system topology, reactance of corridors, line ratings, voltage level, etc.

⁴ Technology details and best practices are discussed in Section 2 of “Alternative Transmission Technologies Framework”.

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- APFCs should generally be avoided on critical transmission lines, such as those connected to nuclear facilities. APFC deployment introduces new layers of complexity to grid operations, particularly when multiple devices are deployed across the system, where the critical lines should not be at additional risks. In addition, APFCs' mis-operation or failure to respond appropriately could lead to overloads, equipment and system stress, or violation of operating limits.
 - APFC can be installed across various voltage levels. However, at EHV level (i.e., 300 kV and above), APFC installation might not be practical due to increased clearance requirements, larger insulator dimensions, and a significantly larger installation footprint. These factors often make APFC deployment at EHV impractical. In addition, the number of required APFCs increases proportionally with line rating and the square of voltage level (number of APFCs $\propto$ Rate $\times$ kV²), meaning it increases linearly with line rating and quadratically with voltage level. Thus, for the same reactance injection, additional APFC devices are required in EHV compared to HV and MV.
 - APFC deployment depends on the available physical space at the monitoring facility and the number of devices required. For facilities with limited or constrained space, conventional solutions such as reconductoring may be more practical. For instance, it might not be practical and cost-effective to accommodate APFC devices in short transmission lines. In contrast, for facilities with sufficient space to accommodate the required equipment, APFCs may offer a more cost-effective solution.
 - Furthermore, considering modularity of APFCs, they can be implemented as an intermittent, short-term solution in temporary violation scenarios, such as during planned outages or when critical equipment is unavailable due to long lead times for replacement or repair, as outlined in Requirement R2.1.4 of TPL-001-5.

Table 4 summarizes key features influencing the feasibility of APFC implementation.

Despite the growing interest in APFC technologies and their demonstrated potential to improve transmission efficiency and flexibility, several technical, operational, regulatory, and economic challenges still hinder their widespread adoption, including limited field deployment experience, compatibility issues with legacy systems, cybersecurity concerns, and hurdles related to regulatory and market acceptance.

APFCs are considered a simulation-based and controlled solution, meaning that once they are determined to be a practical and feasible option by the engineering and design team during the planning process, additional power flow and dynamic simulations are required to ensure they are not introducing any violation into the system or jeopardize system stability.

Once APFC is deemed a feasible solution, the appropriate sizing and number of devices should be determined. The recommended approach involves incrementally increasing the line reactance on the overloaded facility until the overload is mitigated. After reactance adjustment, the corresponding line current should be recorded. Using the desired reactance and observed current flow, the required number of APFC units can then be calculated based on the device's performance characteristics. For instance,

Figure 6 illustrates the SmartValve sizing calculator, which determines the appropriate number of units for two device models based on the target reactance and line current.

Table 4. Key Factors Influencing the Feasibility of APFC Implementation

Key Feature	Feasibility Impact
Radial Index	APFC is only feasible on non-radial corridors where power can be rerouted; infeasible on radial paths.
Contingency Impact Scope	More effective when multiple overloaded facilities belong to the same corridor; less practical across multiple corridors.
AC% Loading	Most practical for overloads up to ~140–150% of line rating; above that, cost and operational complexity increase.
Facility Location	Avoid on lines serving critical facilities due to operational risk, complexity, and potential impact of mis-operation.
Voltage Level	Applicable at MV and HV; less practical at EHV due to size, clearance, and high number of required units.
Space Availability	APFC deployment depends on the available physical space at the monitoring facility and the number of devices required

Voltage Injection PU Using PSSE FACTs model			
SVRating	717	1434	
SV#	10-1800	10-3600	
1	0.042623511	0.021311756	
2	0.085247022	0.042623511	
3	0.127870534	0.063935267	
4	0.170494045	0.085247022	
5	0.213117556	0.106558778	
6	0.255741067	0.127870534	
7	0.298364578	0.149182289	
8	0.340988089	0.170494045	
9	0.383611601	0.1918058	
10	0.426235112	0.213117556	
11	0.468858623	0.234429311	
12	0.511482134	0.255741067	
13	0.554105645	0.277052823	
14	0.596729156	0.298364578	
15	0.639352668	0.319676334	
16	0.681976179	0.340988089	
17	0.72459969	0.362299845	
18	0.767223201	0.383611601	
19	0.809846712	0.404923356	
20	0.852470224	0.426235112	

Min MVA	40	MVA
Nominal voltage	230	
MVA Base	100	
Zbase	529	Ohms
Final X	0.02843	pu
Original X	0.01093	pu
Xinj	0.017500	pu
Xinj	9.258	Ohms
Final current	1176.46	Amps
Vinj	10891.08	Volts
Vinj	10.89	kV
10-1800	5.66	kV
SV 10-1800	1.924218807	decimals
10-3600	2.83	kV
SV 10-3600	3.848437615	decimals
SV 10-1800	2	Unit
SV 10-3600	4	Unit

	V (pu) from PSSE	10-1800	10-3600
#Of SV based on Vinj	0.44	11	21

Figure 6. SmartValve Sizing Calculator⁵

⁵ <https://www.smartwires.com/smartvalve/>

4.2.4. Transmission Switching Implementation Feasibility Guidelines

Transmission switching⁶ is a proven operational and planning tool used to alleviate congestion and mitigate thermal overloads on transmission lines. The core principle involves modifying the network topology, by opening or closing circuit breakers, to reroute power flows from overloaded elements to alternate, underutilized corridors. There are two primary forms of transmission switching:

- Switching the overloaded facility itself, redirecting power flow to a parallel corridor(s); and
- Switching another line(s) within the system that is not overloaded, which may relieve congestion elsewhere through system rebalancing. This is typically known as topology optimization.

Once a violation is identified, that is categorized as a thermal violation per violation category decision tree in Figure 3, and ATTs are deemed feasible per decision trees in Figure 4 and Figure 5, transmission switching should be considered as a possible alternative in the following scenarios:

- Transmission switching is only viable if the overloaded facility is not in a radial corridor in post-contingency situation, otherwise there would be no alternative corridor to reroute flow away from the overloaded facility to the unutilized corridor. Accordingly, non-radiality is a necessary, but not sufficient condition for feasibility of transmission switching. Transmission switching in a radial path would have no rerouting capability and is equivalent to load shedding or generation curtailment, thus considered infeasible
- Transmission switching is only viable if the alternative corridors can absorb the redirected power without exceeding their own thermal limits. Thus, transmission switching is only feasible when they do not introduce secondary overloads in the system.
- Once multiple facilities are overloaded due to a contingency occurrence, transmission switching might be a feasible solution if the overloaded facilities all belong to the same corridor. Otherwise, transmission switching is not a practical alternative.
- Transmission switching should generally be avoided on critical transmission lines, such as those connected to nuclear facilities. Transmission switching introduces new layers of complexity to grid operations, where the critical lines should not be at additional risks.
- Transmission switching sequences can be implemented across various voltage levels. However, at EHV level (i.e., 300 kV and above), transmission switching might not be practical due to typical limitations on parallel corridors.
- Transmission switching can be used as a temporary mitigation strategy when traditional transmission construction is delayed. It can also be applied to address system violations resulting from known outages, as outlined in Requirement R2.1.4 of TPL-001-5.

⁶ Technology details and best practices are discussed in Section 3 of “Alternative Transmission Technologies Framework”.

- When defining a transmission switching project, the operations team must understand the specific conditions under which switching should be implemented, as well as the scenarios in which the system can be restored to normal configuration. Therefore, the study engineer must analyze the system characteristics at the time of the violation. For example, a marginal overload occurring during a light load condition, such as in a spring off-peak scenario, may be a suitable candidate for mitigation through transmission switching.
- From a reliability standpoint, transmission switching is generally a more feasible solution for marginal violations that occur during prior outage contingencies or extreme events, rather than for single-contingency (P1) violations. This is because, when transmission switching is considered as a solution for a P1 violation, multiple prior outage scenarios must still be studied. This increases the risk of introducing new overloads when the switching action is implemented.
- Transmission switching or topology optimization are generally not viable solutions in weaker parts of the system or in areas that are poorly interconnected with the rest of the grid. As a rule of thumb, if a credible contingency occurring while the switching action is in place would create a large electrical island with multiple generation and load centers, the switching should not be considered a feasible option unless the associated risks are thoroughly assessed.

Table 5 summarizes key features influencing the feasibility of transmission switching implementation.

Despite the growing interest in transmission switching implementation, several technical, operational, and regulatory challenges still hinder their widespread adoption, including Lack of established reconfiguration protocols, cybersecurity and protection coordination, computational complexity and tool limitations.

Transmission switching is considered a simulation-based and controlled solution, meaning that once it is determined to be a practical and feasible option, additional power flow and dynamic simulations are required to ensure they are not introducing any violation into the system or jeopardizing system stability.

Table 5. Key Factors Influencing the Feasibility of Transmission Switching Implementation

Key Feature	Feasibility Impact
Radial Index	Transmission switching is only feasible on non-radial corridors where power can be rerouted; infeasible on radial paths.
Contingency Impact Scope	More effective when multiple overloaded facilities belong to the same corridor; less practical across multiple corridors.
Facility Location	Avoid on transmission lines serving critical facilities due to operational risk, complexity, and potential impact of mis-operation.
Voltage Level	Applicable at MV and HV; less practical at EHV due to operational limitations.

4.2.5. Dynamic Line Rating Implementation Feasibility Guidelines

DLR⁷ uses measured and/or forecasted weather and line-condition data to calculate the safe current-carrying capability of an overhead transmission line as conditions change. Unlike a physical upgrade, DLR does not permanently increase conductor capability or clearance; it identifies additional thermal headroom when actual conditions provide more cooling than the assumptions embedded in static or seasonal ratings.

Once a violation is identified as a thermal violation per the violation category decision tree in Figure 3, and ATTs are deemed feasible per the decision trees in Figure 4 and Figure 5, DLR should be considered with respect to the following points:

- Prior to considering DLR, utilities should establish a representative DLR profile that provides an indication of the expected rating increase under different ambient temperatures, wind speeds, and seasonal conditions. This profile can help characterize the range of incremental capacity that may reasonably be expected under typical and favorable operating conditions.
- Utilities should identify the limiting span or element that ultimately constrains the usable DLR capacity of a line. While the conductor itself may support a higher thermal rating, localized conditions such as reduced wind exposure, higher temperatures, or sag/clearance limitations at a critical span may restrict the practical rating increase for the overall line.
- DLR is most suitable for marginal to moderate overloads where the required incremental capacity can be provided frequently and reliably by favorable ambient conditions. DOE demonstrations report typical increases of approximately 10–40% above static ratings, while individual projects have observed larger gains under favorable conditions. Therefore, a practical screening range is generally an overload up to approximately 110–140% of the static rating, subject to site-specific historical and forecast weather analysis.
- Higher DLR gains can occur, but they are weather-dependent and should not be assumed as firm capacity without supporting data. DOE case studies include capacity increases of 30–44% over static ratings for NYPA and average increases of 30–70% relative to static ratings for Oncor, while Oncor observed only 6–14% over ambient-adjusted ratings. However, these higher gains represent condition-dependent capability rather than capacity that can be assumed to be consistently available when needed. Accordingly, overloads substantially above the typical 110–140% screening range should be evaluated on a site-specific basis rather than assumed feasible based on the maximum DLR gains reported in individual demonstrations.
- DLR is most valuable when the overload is correlated with conditions that also increase line cooling, such as lower ambient temperature and/or favorable wind. If the violation must be

⁷ Technology details and best practices are discussed in Section 9 of “Alternative Transmission Technologies Framework”.

resolved under all weather conditions or requires a guaranteed year-round increase in rating, DLR alone is generally not an appropriate mitigation because the available dynamic rating can fall back to, or in unfavorable conditions below, the seasonal/static value used for planning.

- Summer overloads require particular caution. High ambient temperature, strong solar heating, and low wind reduce conductor cooling, so the DLR may provide little additional capacity precisely during some peak summer hours. DLR should not be credited as a firm solution to a summer peak violation unless historical/forecast weather analysis demonstrates that sufficient dynamic rating is available during the critical hours; otherwise the overload can remain unchanged or become more restrictive than expected.
- The limiting element must be verified before DLR is considered. DLR can increase utilization only when the conductor thermal capability is the relevant adjustable limit and all other equipment and system limits remain above the calculated dynamic rating. If the facility is limited by a non-dynamic terminal component (e.g., breaker, disconnect switch, wave trap, jumper, or other equipment), DLR cannot increase the facility rating beyond that component limit.
- Clearance and sag must remain within applicable limits at every DLR value. DLR may use sag, tension, conductor temperature, or weather measurements to determine a safe current while respecting clearance. However, DLR does not correct existing physical under-clearance condition. If a span already lacks the required ground or object clearance at the applicable maximum conductor temperature, the physical constraint must be corrected (e.g., structure modification, re-tensioning, or reconductoring) before additional ampacity can be credited.
- DLR feasibility should be established using line-specific weather variability, sensor/forecast accuracy, communications availability, data quality, and fallback logic. A conservative fallback rating should be available when measurements, forecasts, or communications are unavailable or invalid.
- DLR is generally better suited to overhead transmission lines than underground cables and should be evaluated on lines where weather-driven conductor cooling materially affects ampacity. The benefit is location-specific and may vary significantly along the line; critical spans and microclimates should therefore be identified during implementation.

Table 6 summarizes key features influencing the feasibility of DLR implementation.

DLR is considered a simulation- and operations-dependent solution. Planning studies should evaluate the range of available ratings, the coincidence between overloads and weather conditions, and the consequences of rating reduction. Operational implementation requires validated calculations or sensors, short-term forecasting where applicable, communications and control-room integration, alarms/validity flags, and a defined fallback rating.

Table 6. Key Factors Influencing the Feasibility of Dynamic Line Rating Implementation

Key Feature	Feasibility Impact
Facility Type	Applicable primarily to overhead transmission lines where weather-dependent conductor thermal capability governs the usable rating.
AC% Loading	Most attractive for marginal/moderate overloads. A screening range of about 110–140% is supported by many demonstrations; higher gains are possible but should not be assumed as firm capacity without line-specific evidence. Persistent ~170% loading is generally not a DLR-only case.
Limiting Element	Feasible only when the dynamic conductor rating remains below all terminal-equipment, clearance, and system limits. Non-dynamic equipment limits cap the usable DLR.
Weather / Seasonal Correlation	High feasibility when overload periods coincide with favorable cooling. Lower feasibility for hot, low-wind summer peaks or when a firm year-round rating increase is required.
Ground Clearance / Sag	DLR must preserve required clearance and may use sag/tension/temperature data, but it does not physically correct an existing under-clearance span.
Operational / Data Requirements	Requires reliable measurements or weather data, forecast/estimation accuracy, communications, control-room integration, validity checks, and a conservative fallback rating.

4.2.6. Alternative Technology Selection Decision Tree

All implementation guidelines and feasibility considerations for ATTs, as outlined in Section 4.2, are incorporated into a structured decision-making process using two sequential decision trees, illustrated in Figure 7 and Figure 8. The decision tree in Figure 7 initiates the assessment by identifying the violation and proceeds through the feasibility screening logic described in Sections 4.1.1 to 4.1.3, which evaluates the violation category, facility type, and contingency cause.

Once ATT feasibility is confirmed through Figure 7, the process advances to Figure 8, which evaluates the viability of each specific technology: advanced conductors, tower lifting, APFC, transmission switching and DLR, using additional key technical features. This tiered structure ensures a comprehensive, consistent, and traceable evaluation of mitigation options tailored to the unique attributes of each thermal violation scenario.

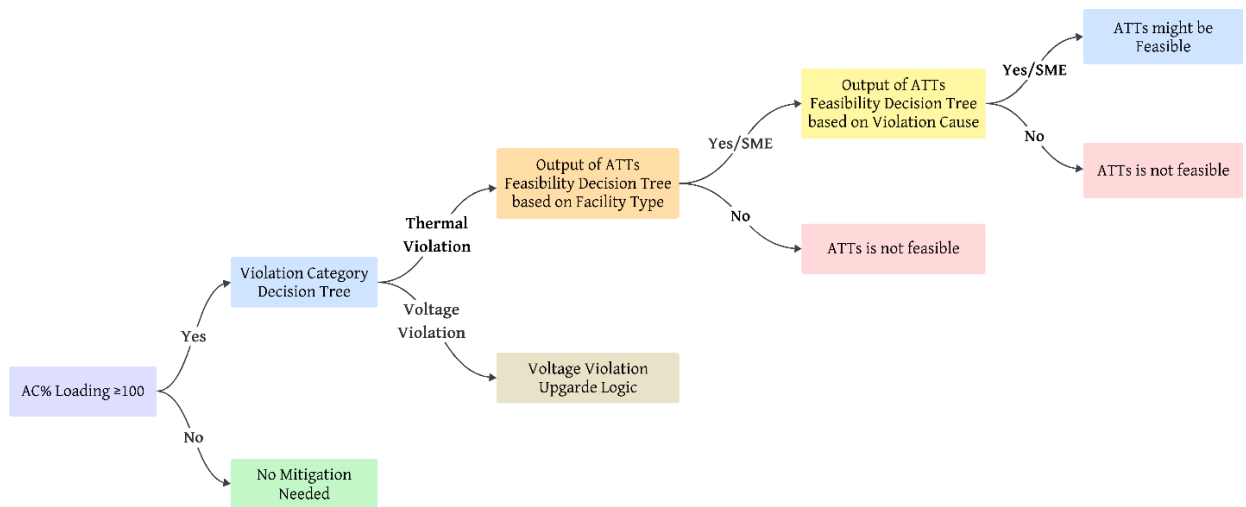


Figure 7. Initial ATT Feasibility Decision Tree Incorporating Violation Type, Facility, and Contingency Logic

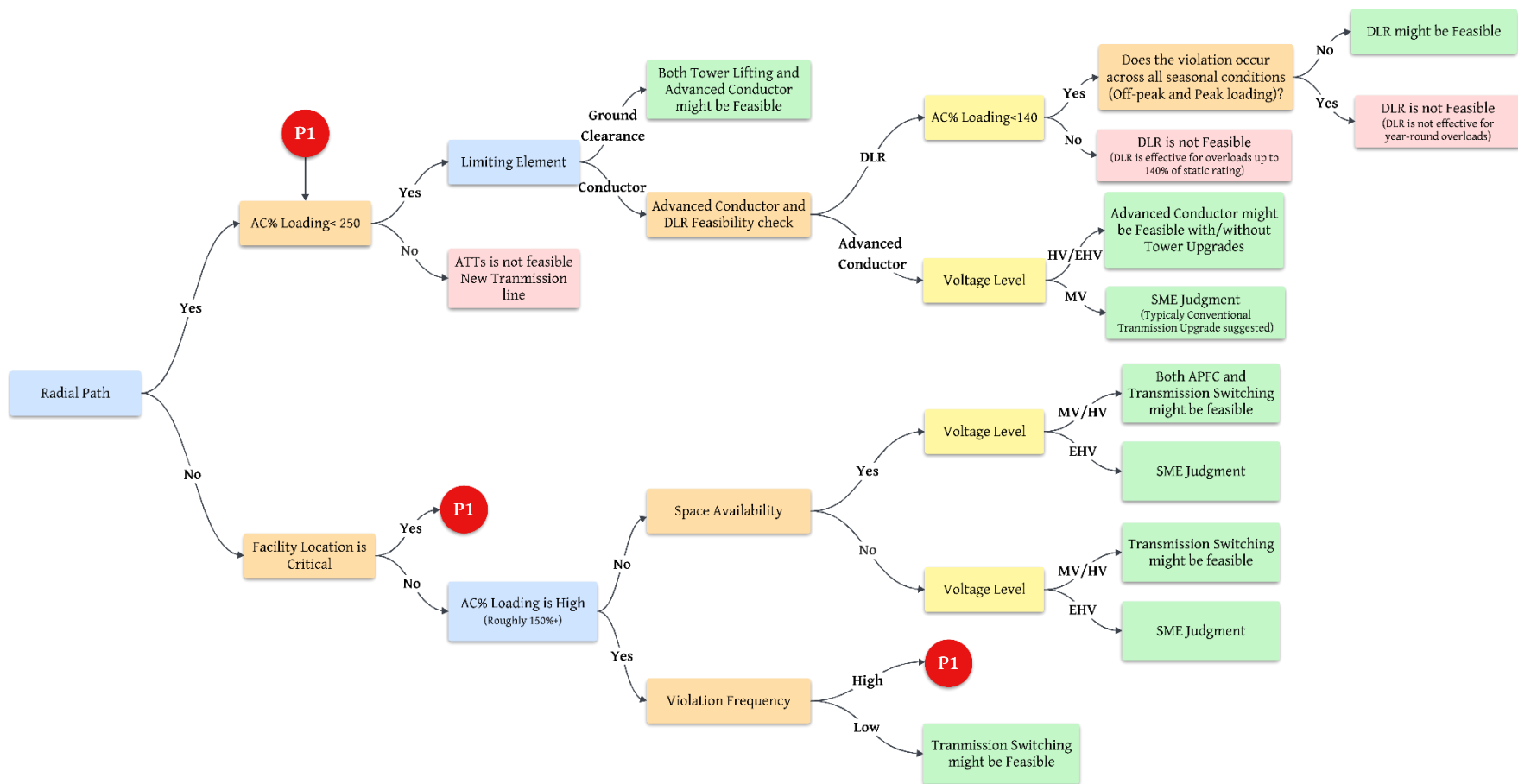


Figure 8. Technology-Specific ATT Selection Decision Tree for Thermal Violations

5. Technology Comparison

This section presents a high-level comparison of five ATTs, advanced conductors, tower lifting, APFC, transmission switching, and DLR based on their typical implementation costs, required outage durations, and overall deployment timelines. These factors are critical in evaluating and prioritizing ATT options after feasibility is established. While technical feasibility may justify a given solution, practical constraints such as extended outages or long lead times may render some technologies less desirable. Table 7 provides a side-by-side summary of key implementation parameters and considerations for each technology.

Advanced conductors typically cost between \$200,000 and \$600,000 per mile, depending on conductor type, voltage level, terrain, and installation requirements. These projects often involve extended outage durations ranging from several months to over a year, particularly when paired with structure modifications or permitting delays. The overall implementation timeline is approximately 18 to 36 months, including engineering design, permitting, procurement, and construction. Despite longer timelines, advanced conductors offer increased ampacity and reduced sag, enabling significant boost thermal ratings without the need for new ROW. However, widespread adoption remains limited by challenges such as the need for structural assessments and the lack of standardized conductor test data.

Tower lifting provides a cost-effective solution for increasing clearance and thermal capacity without expanding the transmission corridor. Its cost typically ranges from \$400,000 to \$1 million per mile equivalent, assuming 5–8 towers per mile and a unit cost of approximately \$70,000–\$150,000 per tower. Outage durations can often be minimized from energized lift to just a few days. The time to implement ranges from days to a few weeks per segment, depending on the number of towers and required engineering assessments. While tower lifting offers clear advantages in ROW-constrained environments, its standalone impact is limited unless combined with conductor upgrades, and implementation may be constrained in areas with harsh weather conditions or aviation height restrictions.

APFC devices, such as SmartValves, are priced around \$2 million per device, with overall project costs varying based on the number of units and voltage level. These systems generally require outage durations of days to weeks for installation, especially in energized environments with complex substation configurations. Full implementation timelines typically range from days to several weeks. APFC systems allow for dynamic power flow adjustments, improving utilization of underloaded corridors and reducing the need for new infrastructure. However, APFC deployments require careful coordination of protection settings, cybersecurity review, and operational planning to ensure compatibility with existing grid systems.

Transmission switching is a cost-effective and rapid ATT option, with installation costs generally ranging from \$100,000 to \$200,000 per switching scheme, depending on location and control system upgrades. It often requires only hours to a few days of outage time, particularly when switching involves breaker operations or automated controls rather than physical infrastructure changes. The implementation timeline is typically a few days, including validation of protection settings, relay coordination, and operational approvals. While transmission switching offers significant flexibility and is highly suitable for managing temporary violations or congestion, it also involves complex system studies and may introduce cybersecurity and coordination challenges in systems lacking real-time monitoring or switching protocols.

Dynamic Line Rating typically costs US \$15,000–60,000 per mile, depending on factors such as line length, number and type of monitoring devices, communication needs, and integration with utility operational systems. Because DLR relies primarily on installing monitoring equipment and associated communications on existing lines, it generally requires little to no planned outage for installation. Implementation can typically be completed within several weeks to a few months, depending on engineering, procurement, system integration, and commissioning. DLR offers a cost-effective means of increasing utilization of existing transmission assets by capturing additional thermal capacity under favorable conditions, potentially deferring more capital-intensive upgrades; however, its performance depends on weather conditions and reliable sensing, communications, and integration with operational systems.

Table 7. Comparative Summary of ATTs by Cost, Outage Duration, and Implementation Timeline

Technology	Cost Estimate	Outage Duration	Time to Implement	Technical Considerations
Advanced Conductor	USD \$200k–600k per mile	Months to over a year	18–36 Months	Pros: - Increased loading limits and high-temperature low-sag options - Suitable for climate-stressed corridors Cons: - Limited test data and long pre-deployment validation cycles - Requires detailed structural assessments and permitting
Tower Lifting	USD 400k–1M per mile Equivalent ¹	No outage or Days	Days to weeks	Pros: - Increases clearance without ROW expansion Cons: - Detailed structural assessments required - Limited effectiveness unless combined with reconductoring - Implementation limitation in areas with extreme weather conditions
APFC (Smart Valve)	USD \$2M per Device	Days to weeks	Days to weeks	Pros: - Deployable in modular form to temporarily mitigate constraints - Providing reactive power support and improving oscillation damping through real-time impedance adjustments Cons: - Requires protection and cybersecurity assessments - Adds operational complexity
Transmission Switching	USD \$100k–200k per Installation	Hours to Days	Days	Pros: - Intermittent solutions for temporary violations, e.g., planned outages or long lead time of equipment. Cons: - Computational complexity and tool limitations - Cybersecurity and protection coordination concerns
Dynamic Line Rating	USD \$15k–60k per mile	No outage or minimal outage	Weeks to months	Pros: - Increases utilization of existing transmission capacity without major physical upgrades - Relatively fast deployment Cons: - Capacity increase is weather-dependent and cannot be guaranteed year-round - Requires reliable weather/line measurements, communications, forecasting, and control-room integration

¹ Considering 5-8 towers per mile and \$70,000–150,000+ per tower

6. Feasibility Procedure Extension for Annual TPL Study

The current ATT decision-making procedure is designed to evaluate the feasibility of alternative technologies based on static base-case violation characteristics. However, Annual Transmission Planning (TPL) reliability assessments require a forward-looking perspective to ensure that mitigation strategies remain robust under evolving system conditions. In particular, load growth and generation growth projections, as well as their substation-specific impacts under contingencies, can significantly alter facility loading in future study years.

To address this, four additional features have been defined in Section 3 that are particularly relevant to TPL studies, including Load Impact, Load Growth, Generation Impact, and Generation Growth. While these features are not currently incorporated into the decision-making process or screening logic, their potential influence on ATT feasibility is non-negligible. For example, even when a violation appears marginal in a near-term study year, high projected load or generation growth could render the same violation more severe in future horizons, shifting the feasibility or priority of specific ATTs.

It is important to note that incorporating these features would increase the decision tree complexity by a factor of up to $3^4 = 81$, assuming three value ranges per feature. Moreover, this data may not always be readily available for all identified violations. As such, this section provides guidance to SMEs on how to interpret these future-looking features when applying ATT screening logic in the context of annual TPL studies.

6.1. Influence of Load Growth on ATT Feasibility and Probability

As system load increases over time, its effect on ATT feasibility depends not only on how much the load grows but also on how that load growth impacts the monitored facility under contingency conditions. Below are technology-specific considerations for interpreting Load Growth and Load Impact during ATT screening:

- **Advanced Conductors:** Substantial future load growth may push a line's loading from moderately overloaded (e.g., 130%) to severely overloaded (e.g., >250%). In such cases, conventional reconductoring with advanced conductors may no longer suffice, and a new line build may become necessary. Load growth may reduce the feasibility probability from *High* to *Low*.

-
- **Tower Lifting:** Tower lifting is most effective when the thermal limit is driven by ground clearance violations rather than conductor ampacity. If future load growth causes conductor temperature to rise well beyond clearance limits, tower lifting alone may not be sufficient, unless paired with advanced conductors. This may shift feasibility from *Yes* to *No*.
 - **APFC:** As load grows, overloaded corridors may require larger power flow redirection. If the alternate corridors lack hosting capacity, or multiple APFC units would be required to reroute flow, the practicality of APFCs may diminish. Thus, moderate load growth may reduce APFC probability from *Medium* to *Low*.
 - **Transmission Switching:** For violations occurring under light-load conditions, transmission switching is often a feasible, low-cost option. However, increased load may reduce margin for switching actions, or make switching-induced flow shifts ineffective, especially if nearby facilities also become constrained. Feasibility may degrade under high-growth conditions.
 - **DLR:** Increasing load may increase the magnitude and duration of thermal overloads and therefore the rating increase required from DLR. Moderate growth may reduce DLR feasibility, while substantial or persistent growth that exceeds achievable dynamic ratings may make DLR unsuitable.

6.2. Influence of Generation Growth on ATT Feasibility and Probability

Generation growth, particularly from new interconnection requests, can significantly increase stress on specific corridors depending on DFAX and contingency redistributions. Each ATT responds differently to such growth:

- **Advanced Conductors:** As new generators inject more power onto existing corridors, the overall ampacity requirements rise. If the projected growth remains within the enhanced thermal rating range of advanced conductors, feasibility remains the same. However, for *multiple queued projects* impacting the same line, feasibility may drop if reconductoring no longer suffices.
- **Tower Lifting:** If generation growth causes sag-related violations under high MVA flows, tower lifting can be an effective incremental fix, especially when combined with conductor upgrades. However, like load growth, its effectiveness diminishes as ampacity not clearance becomes the limiting factor.
- **APFC and Transmission Switching:** Generation growth may increase grid complexity and overload alternate corridors, thereby reducing hosting capacity for flow redirection. However, in systems with well-meshed topologies, APFCs and Transmission Switching may remain viable by exploiting underutilized paths. Thus, feasibility becomes site- and topology-dependent.

-
- **DLR:** Generation growth, particularly from new interconnections with high DFAX on the monitored facility, may increase corridor loading and the amount of incremental capacity required from DLR. If the additional generation produces only moderate or intermittent overloads that coincide with favorable ambient conditions, DLR feasibility may remain *High* or *Medium*. However, as additional generation projects increase the required transfer capability, the needed rating increase may exceed what DLR can reliably provide, and therefore reduce feasibility of DLR.

6.3. Combined Impact of Load and Generation Growth

When both load and generation growth affect a facility, the interaction of their respective impacts must be carefully evaluated:

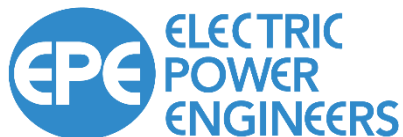
- If both aggravate the violation under the same contingency scenario, the overall loading trajectory is exponential, making temporary or marginal solutions infeasible. In such cases, ATT options like APFC or transmission switching may be ruled out altogether, while advanced conductors or rebuilds may be the only viable long-term solution.
- If load growth and generation growth affect the facility in opposite directions (e.g., load aggravates, generation helps), SMEs should consider the net impact and use sensitivity scenarios to determine feasibility shifts.
- In areas where load and generation both fluctuate seasonally or hourly, hybrid or modular solutions such as APFC may offer scalable mitigation pathways until more robust solutions are justified. DLR may provide flexible incremental capacity when periods of high loading coincide with favorable ambient conditions. However, if peak loading occurs during unfavorable weather conditions, the available DLR uplift may be limited, reducing its effectiveness as a mitigation option.

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Advanced Transmission Technologies Procedure

**Decision Making,
Voltage Violations**

Presented To:

Indiana Utility
Regulatory
Commission



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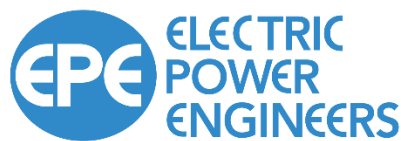
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1. Introduction

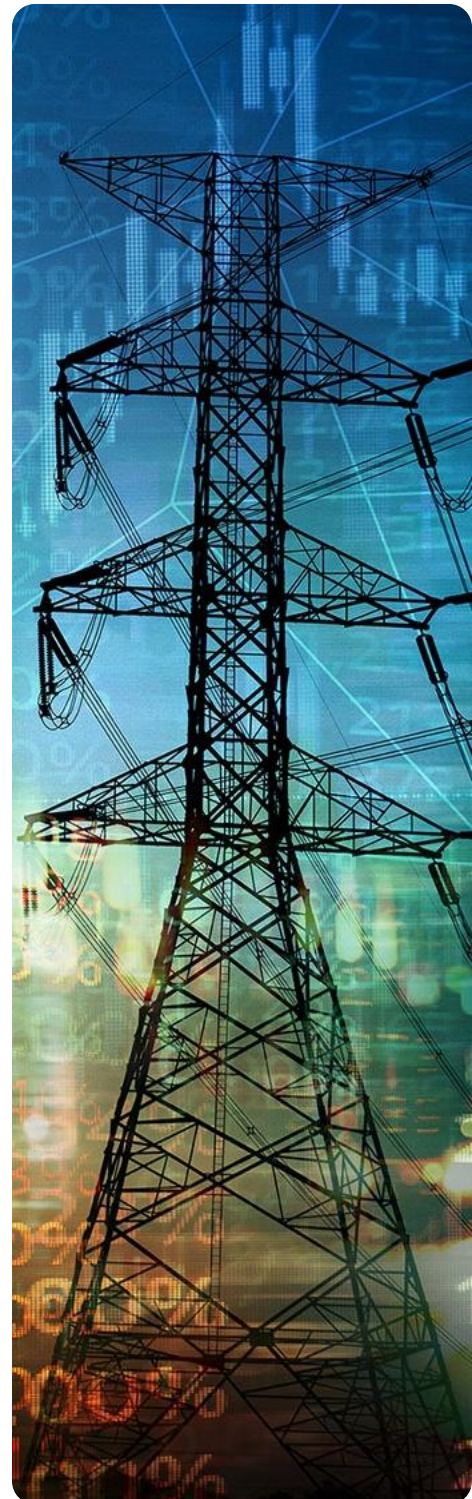
Advanced Transmission Technologies (ATTs) offer planning engineers a suite of non-conventional solutions that can often be deployed more rapidly, cost-effectively, and with minimal disruption to the existing grid compared to traditional transmission infrastructure upgrades.

This document provides a systematic procedure for screening the feasibility of these technologies in addressing voltage violations identified through steady state and stability planning studies.

The methodology presented in this document is built around a structured decision-making framework that begins with a clear understanding of the root-cause of each voltage violation. As outlined in **Section 2**, voltage violations are first classified based on the type of study in which they are identified, either steady state or stability studies. This classification informs the selection and prioritization of appropriate technologies and mitigation strategies.

Section 3 of this document provides detailed guidance on the application of individual technologies, including Synchronous Condensers (SynCons), Static Synchronous Compensators (STATCOMs), and Static VAR Compensators (SVCs). These technologies represent the core set of ATTs evaluated in this document. Although Voltage Source Converters (VSCs) represent an underlying component of STATCOMs, VSC is not treated as a standalone technology in this document. Instead, its capabilities are inherently reflected in the performance characteristics and modular design advantages of STATCOM solutions, which are already considered as a distinct ATT category.

Error! Reference source not found. presents a high-level overview of the ATT feasibility evaluation process, which is detailed throughout this document. The process begins with the identification and verification of voltage violations. This



step constitutes a generic study procedure that is already well-established within current transmission planning and generation interconnection workflows.

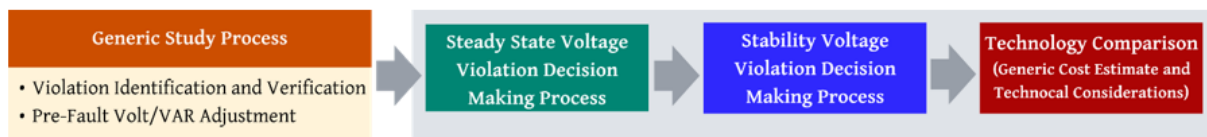


Figure 1. Overview of the ATT Feasibility Evaluation Process for Voltage Violations

Following this initial verification step, the methodology branches into decision-making paths, first the steady state voltage violation process, and then the stability voltage violation process. In practice, these two processes are closely interconnected. A mitigation strategy identified as feasible for a steady state voltage violation must also be evaluated through stability analysis to confirm that it does not introduce adverse dynamic impacts. Similarly, mitigation planning for stability violations often begins by considering steady state adjustments, since operational changes may resolve the stability issue without requiring additional measures.

Finally, **Section 5** presents a comparative evaluation of the key technologies discussed, including their response time, cost, technical attributes, and appropriate voltage levels. This comparison supports engineers in prioritizing technologies for feasibility studies and in documenting rationale for technology selection or exclusion in planning reports.

2. Root-Cause of Voltage Stability Issue

To develop a robust decision-making process for deploying ATTs in response to voltage violations, it is essential to first understand the underlying nature of the problem. Voltage violations are typically categorized based on the type of planning or operational study in which they are identified, either steady state studies or stability studies. Each study type highlights different aspects of system behavior and therefore informs a different set of feasible mitigation strategies.

This classification enables a more targeted evaluation of ATTs by aligning the technical capabilities of each technology with the root cause of the voltage issue. This ensures that the selection of mitigation options remains both technically appropriate and operationally effective.

2.1. Steady State Voltage Violations

Steady state voltage violations refer to conditions in which voltage magnitudes fall outside established acceptable operating ranges or exhibit excessive deviations from pre-contingency values. These violations are typically identified through power flow simulations under normal or contingency conditions. Steady state issues generally manifest as either voltage magnitude violations or voltage deviation violations. A voltage magnitude violation occurs when the voltage at a bus is too low or too high relative to planning limits. A voltage deviation violation occurs when the post-contingency voltage changes too significantly from the pre-contingency value, even if the final voltage remains within the acceptable range.

The acceptable limits for both voltage magnitude and deviation are guided by regulatory and planning standards. These standards provides detailed thresholds in compliance with **NERC TPL-001-5.1** standards. These include:

- **Voltage Ranges:** Expressed as a percentage of nominal voltage for different contingency categories (P0–P7) across both High Voltage (HV) and Extra High Voltage (EHV) levels.
- **Voltage Deviation Limits:** Also given in percent deviation from base voltage, indicating the maximum allowable change following a contingency, for different contingency categories (P0–P7) across both HV and EHV levels

When steady state violations are detected, the first course of action typically involves **Volt/VAR adjustments** within permissible operating limits. If these adjustments are insufficient, reactive power support might need to be included through technologies such as Switched Shunts (capacitor banks or reactors), SVCs, STATCOMs, SynCons, etc. The selection of these technologies will be further discussed in Sections 3 and 4 of this document.

2.2. Stability Voltage Violations

Stability-related voltage violations are identified through dynamic simulations that assess system performance during and after disturbances. These violations reflect the system's ability to maintain acceptable voltage levels in response to events. Unlike steady state issues, these violations are time-dependent and often reflect the dynamic interplay between system inertia, reactive power support, and control system response. Stability violations generally fall into three categories: transient voltage dip, delayed voltage recovery, and voltage oscillation damping.

Transient voltage dip violations occur when system voltages drop significantly during a disturbance and do not recover within an acceptable time frame. These dips can result in widespread tripping of sensitive loads or generation resources, potentially leading to cascading outages. For example, industry practices often reference thresholds such as voltages not dropping below 0.7 per unit for more than 30 cycles, or below 0.8 per unit for more than 2 seconds. Exceeding these limits can trigger protection systems or destabilize converter-based resources.

Delayed voltage recovery refers to conditions where system voltages remain suppressed for an extended period after fault clearance. This may indicate insufficient dynamic reactive support or weak system strength. A commonly referenced threshold is voltage remaining below 0.8 per unit for more than 20 seconds following a disturbance. Such prolonged low-voltage conditions can disrupt service, affect motor loads, and lead to thermal damage in equipment.

Voltage oscillation damping violations occur when post-disturbance voltage profiles exhibit sustained or poorly damped oscillations. These oscillations may reflect unstable control dynamics, inadequate damping from generation or compensation devices, or low short-circuit strength. Two important indicators are the peak-to-peak voltage ratio and overshoot magnitude. For instance, voltage should not exceed 1.25 per unit during post-fault rebound, and the oscillation amplitude (i.e., the difference between peak and valley) should remain within 10 percent of nominal voltage. Larger deviations signal poor damping or instability.

Stability-related voltage violations may, in some cases, be resolved through **pre-fault Volt/VAR adjustments** or by **tuning the dynamic models and control parameters** of nearby facilities, such as generators or existing reactive devices. These adjustments can improve the local voltage response and enhance damping behavior. However, if such measures are not effective in restoring acceptable performance, then the deployment of fast-response technologies may be necessary. Suitable technologies include STATCOMs, SVCs, and SynCons. In systems characterized by low Short Circuit Ratio (SCR), SynCons are often the preferred option due to their ability to provide both dynamic voltage support and rotational inertia. The selection of these technologies will be further discussed in Sections 3 and 4 of this document.

3. Alternative Technologies for Voltage Violations

This section outlines the alternative technologies available for mitigating voltage violations, with a focus on implementation scenarios based on technical capability and industry best practices. The objective is to provide actionable guidance for each technology, considering both steady state and stability-related voltage issues. These implementation guidelines serve not only as a reference for evaluating deployment practicality, but also as a structured basis for documenting infeasibility justifications and preliminary feasibility rationales in planning reports. Each subsection provides focused insights into when and how each technology may be effectively applied, helping planners align mitigation strategies with system needs and operational constraints.

3.1. Static Synchronous Compensators (STATCOMs)

STATCOM is a flexible AC transmission system (FACTS) device used to regulate voltage by providing dynamic reactive power support. This section presents typical planning scenarios where STATCOM implementation may be considered a feasible alternative for mitigating voltage violations. For further background on STATCOM operating principles and industry best practices, refer to the **“Advanced Transmission Technologies Framework”** document prepared by EPE.

- STATCOMs are particularly effective in addressing stability-related voltage violations where fast-response and real-time reactive power injection or absorption is critical. Their ability to respond within a few cycles allows them to support voltage recovery following disturbances, reduce transient dips, and help maintain system voltage within acceptable limits.
- Compared to SVCs, STATCOMs offer superior performance under low-voltage conditions due to their ability to maintain full capacitive compensation even as system voltage drops. This makes them more effective in supporting transient stability in stressed or weak areas of the grid.
- In steady state conditions, when a large amount of reactive power is required, typically above 150 MVAR, a STATCOM can be considered a viable solution. In such cases, it can address steady state violations while also contributing to dynamic stability.
- STATCOMs are also well-suited for applications that require modularity or scalability. Their flexible design allows for staged deployment and fine-tuned control across a wide operating range, providing both inductive and capacitive reactive power support as system conditions evolve.

It is important to note that while STATCOMs offer advanced performance benefits, they are typically associated with higher capital costs compared to conventional solutions.

3.2. Static VAR Compensators (SVCs)

SVC is a FACTS device that delivers fast-acting reactive power support for voltage regulation. Unlike mechanically switched capacitors or reactors, an SVC responds within cycles to voltage deviations, making it highly effective in maintaining system stability. This section presents typical planning scenarios where SVC implementation may be considered a feasible alternative for mitigating voltage violations. For further background on SVC operating principles and industry best practices, refer to the **“Advanced Transmission Technologies Framework”** document prepared by EPE.

- In cases of stability-related voltage violations, SVCs support transient recovery by injecting or absorbing reactive power in real time following contingencies. While SVCs are not as fast or effective under low undervoltage conditions as STATCOMs, SVCs can still contribute to damping oscillations and limiting voltage excursions within seconds following a disturbance.
- SVCs are generally cost-effective and reliable, requiring minimal maintenance due to the lack of rotating parts. They serve well in moderately weak systems but may be less effective in severely low SCR scenarios, where STATCOMs or SynCons are preferred.
- In applications where modularity and scalability are important, SVCs can be configured in expandable blocks. Configurations using modular thyristor-switched capacitor/reactor banks allow capacity adjustments in increments, facilitating staged deployment or future expansions.

It is important to note that while SVCs offer advanced performance benefits, they are typically associated with higher capital costs compared to conventional solutions. On the other hand, SVCs typically have lower capital costs than STATCOMs, they may underperform in scenarios characterized by low SCR or low undervoltage.

3.3. Synchronous Condensers (SynCons)

SynCon is a rotating machine that operates without a prime mover and whose sole purpose is to provide dynamic reactive power support, short-circuit current, and rotational inertia. This section presents typical planning scenarios where SynCon implementation may be considered a feasible alternative for mitigating voltage violations. For further background on SynCon characteristics and planning considerations, refer to the **“Advanced Transmission Technologies Framework”** document prepared by EPE.

- SynCons may serve as an effective solution for addressing stability-related voltage violations, particularly in weak-grid areas or in systems with low SCR. Unlike STATCOMs or SVCs, SynCons inherently provide rotational inertia, which contributes to frequency stabilization and improved voltage stiffness during and after disturbances. In addition, their sub-transient reactance enables them to deliver significant fault current, often five to seven times their rated capacity, thereby strengthening the local short-circuit level and enhancing the performance of protection systems.
- SynCons might be an effective technology for areas with high penetration of inverter-based resources (IBRs), where conventional synchronous machines have been displaced, leading to

reduced system inertia and weakened grid strength. In such environments, SynCons can restore essential system attributes such as rotational inertia, short-circuit current, and voltage support.

- With the continued retirement of conventional synchronous generators, SynCons become practical and cost-effective alternatives, especially through the retrofit of decommissioned generating units. Retrofitting enables planners to repurpose existing infrastructure, significantly reducing capital expenditures and environmental impacts. It also allows for faster deployment and simpler permitting processes compared to new installations.
- SynCons are also suitable for applications where modularity and scalability are critical. They can be deployed as individual machines or in coordinated multi-unit configurations and may be coupled with flywheels to further enhance stored kinetic energy. This flexibility allows utilities to tailor the level of inertia and reactive power support based on evolving system needs, providing redundancy and adaptability over time.

It is important to note that while SynCons offer multiple stability and reliability benefits, they are associated with higher operational and maintenance requirements compared to FACTS devices.

3.4. Transmission Switching

Transmission switching is an operational technique that involves opening or closing selected transmission lines or network elements to modify system topology. It can be a cost-effective alternative for mitigating certain types of voltage violations without requiring new equipment installations. This section presents typical planning scenarios where transmission switching may be considered a feasible alternative. For further background on transmission switching principles and industry applications, refer to the **“Advanced Transmission Technologies Framework”** document prepared by EPE.

- Transmission switching can help address high-voltage violations in transmission systems, particularly when transmission lines are lightly loaded. Under light-load conditions, especially during off-peak periods in winter or spring, the capacitive charging of long transmission lines becomes more significant relative to load demand. This can result in higher receiving-end voltages or notable deviations between pre-contingency and post-contingency voltage levels. By opening a lightly loaded line, the capacitive effect is reduced, which helps bring voltages back within acceptable limits and stabilize the system profile. This approach has been successfully applied in various regional transmission organizations, such as PJM, to control voltage during low-demand conditions.

-
- Transmission switching can also help resolve low-voltage issues in certain post-contingency conditions during peak demand periods. In some cases, closing a previously out-of-service line can redirect power flows and improve voltage support in the affected area. While similar switching actions at lower voltage levels, such as 69 kV circuits or transformers, may also be used for localized post-contingency voltage support, these actions are generally considered outside the scope of Advanced Transmission Technologies as they resemble load management rather than network-wide voltage mitigation.

When appropriately applied, transmission switching can improve voltage profiles, enhance system flexibility, and reduce the need for additional reactive power compensation. However, the effectiveness of this approach depends on system topology, real-time operating constraints, and contingency-specific impacts. Careful study and simulation are essential to ensure that switching actions consistently yield positive voltage performance without introducing unintended reliability concerns.

4. ATTs Decision-Making Process for Voltage Violations

As discussed in Section 2, voltage violations are categorized based on the type of planning or operational study in which they are identified, either steady state studies or stability studies. Each study type highlights different aspects of system behavior and therefore informs a different set of feasible mitigation strategies. Accordingly, tailored decision-making procedures are established for each category. While these procedures are presented separately for steady state and stability voltage violations, they are not applied in isolation and must be cross-referenced to ensure comprehensive evaluation.

In practice, a mitigation strategy identified as feasible for a steady state voltage violation should also be evaluated in stability study to confirm that it does not introduce adverse stability impacts. Similarly, the development of mitigation plans for stability-related voltage violations often begins by considering steady state solutions, since adjustments in steady state operating conditions may resolve the stability concern without requiring additional measures.

In certain scenarios, voltage violations may appear in both steady state and stability studies. In such cases, steady state mitigation plans are examined first to determine whether they can address both violations. If these measures are ineffective, stability-specific alternatives are evaluated to ensure that the final solution provides a robust and coordinated resolution to all observed issues.

4.1. Steady State Voltage Violations Decision-Making Process

In response to a voltage violation identified in a steady state study, this section presents a step-by-step procedure for evaluating ATTs and other potential solutions.

illustrates the decision-making flowchart for steady state voltage violations. The process begins once a violation has been detected and proceeds through the following steps:

- **Violation Verification:** The first step is to confirm the validity of the violation before pursuing mitigation measures. This quality check includes verifying the definition and modeling of contingencies, validating study assumptions, and confirming that applicable voltage criteria are correctly applied. If the study case does not include planned transmission upgrades associated with thermal violations, the voltage violations should be reviewed in conjunction with thermal violations, since proposed mitigation plans for thermal overloads may also resolve voltage concerns. This verification step is a standard practice in all transmission upgrade evaluations and, while essential, is considered outside the scope of the ATTs decision-making process.

-
- **Pre-Fault Adjustment:** If the violation is verified, the next step is to consider non-infrastructure measures such as pre-fault Volt/VAR adjustments. These adjustments may involve changes to nearby reactive power support devices, generator voltage schedules, and transformer tap settings. If such adjustments resolve the steady state voltage violation, the revised operating point should then be evaluated in a stability study to ensure that the solution does not introduce adverse dynamic impacts.
 - **Calculate MVAR Support:** If pre-fault adjustments are not sufficient, additional reactive power support will be required. The size and location of the required MVAR support should be identified, typically by inserting a generic reactive device, such as a fixed shunt, into the post-contingency case and adjusting it until voltage criteria are met. This provides an initial estimate of the necessary reactive support.
 - **MVAR Support Technology:** Once the required reactive power has been determined, potential technologies can be evaluated. Industry experience indicates that when the required support exceeds approximately 150 MVAR, conventional switched shunt devices may become less practical, and FACTS devices such as SVCs or voltage source converter (VSC) devices such as STATCOMs might be more effective alternatives. Note that reinforcing system voltage with addition of a transmission line might be a feasible alternative which might be a cost-effective alternative depending on transmission line length. The selection of technology for steady state voltage mitigation is based on a combination of subject matter expertise, system needs, and cost-effectiveness, as further described in Section 5 of this document.
 - **Steady State and Stability Feasibility Studies:** Once a mitigation strategy is selected, a comprehensive steady state assessment of the proposed solution should be performed under both pre-fault and post-fault conditions. Following the steady state analysis, a stability assessment must be conducted to confirm that the selected solution does not introduce adverse dynamic or transient performance issues.

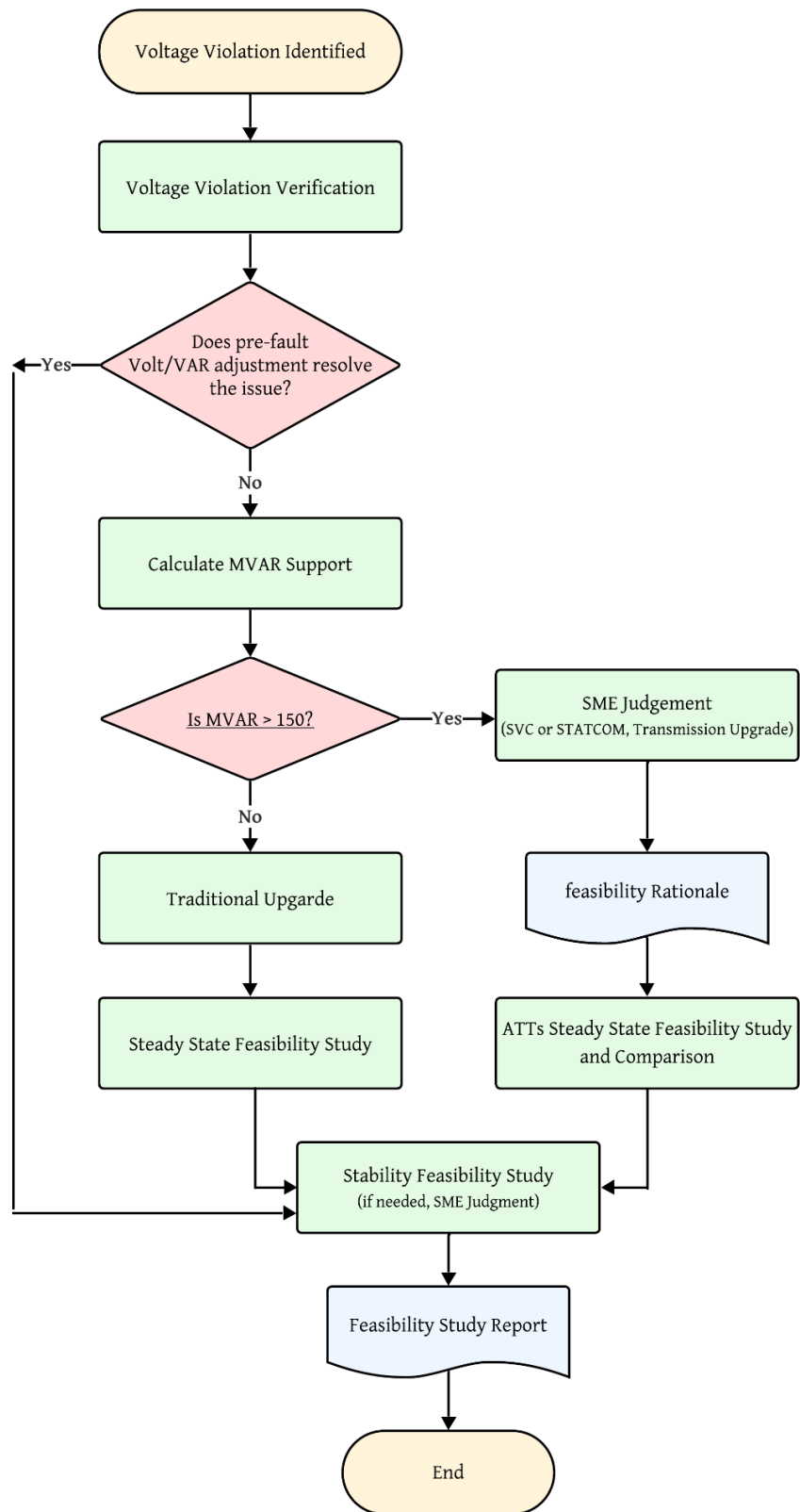


Figure 2. Steady State Voltage Violation Decision Making Flowchart

4.2. Stability Voltage Violations Decision-Making Process

In response to a voltage violation identified in a stability study, this section presents a step-by-step procedure for evaluating ATTs and other potential solutions. Figure 3 illustrates the decision-making flowchart for stability voltage violations. The process begins once a violation has been detected and proceeds through the following steps:

- **Violation Verification:** The first step is to confirm the validity of the violation before pursuing mitigation measures. This quality check includes verifying the definition and modeling of contingencies, validating study assumptions, and confirming that applicable voltage criteria are correctly applied. If the study case does not include planned transmission upgrades associated with thermal violations, the voltage violations should be reviewed in conjunction with thermal violations, since proposed mitigation plans for thermal overloads may also resolve voltage concerns. This verification step is a standard practice in all transmission upgrade evaluations and, while essential, is considered outside the scope of the ATTs decision-making process.
- **Pre-Fault Adjustment:** If the violation is verified, the next step is to consider non-infrastructure measures such as pre-fault Volt/VAR adjustments. These adjustments may include changes to nearby reactive power support devices, generator voltage schedules, or transformer tap settings. Modifying steady state voltage conditions can improve dynamic performance by enhancing pre-fault voltage profiles or reserving reactive power margin in generators for post-contingency voltage support. If these adjustments resolve the violation, the solution should be confirmed in stability simulations to ensure no adverse impacts.
- **Traditional Steady-State MVAR Support:** If pre-fault adjustments are not sufficient, the mitigation process should next examine steady state solutions. Adding reactive power support in steady state, such as fixed or switched shunts, can improve pre-fault voltage levels and reserve generator dynamic reactive capability for use during disturbances. If this approach mitigates the stability voltage violation, a follow-up stability analysis is required to confirm the solution's effectiveness.
- **Dynamic Model Adjustment of Nearby Facilities:** If steady state MVAR support is not effective, adjustments to the dynamic models of nearby facilities should be considered. Modifying control settings, excitation systems, or protection parameters for generators, MVAR support equipment can improve post-disturbance voltage recovery without adding new infrastructure.

-
- **MVAR Support Technology:** If dynamic model adjustments are not effective, the feasibility of deploying STATCOMs, SVCs, or SynCons should be evaluated based on the nature of the violation. Section 3 of this document provides detailed guidelines for technology selection. In general:
 - STATCOMs are effective for stability-related voltage violations requiring fast-response, real-time reactive power injection or absorption. They perform well under low-voltage conditions and are suitable where modularity or scalability is needed but may not be practical in low SCR environments.
 - SVCs can provide effective support for damping oscillations and limiting voltage excursions, though their performance under deep undervoltage is less robust than STATCOMs.
 - SynCons are well-suited for weak-grid or low SCR systems, and for areas with low system inertia.
 - **Feasibility Rationale and Technology Comparison:** If one or more alternative technologies appear feasible, a preliminary “Feasibility Rationale” should be documented. This rationale addresses the question: *Why might the technology be feasible for the identified violation?* The intent is not to conduct a full feasibility study but to record the technical basis for proceeding to more detailed evaluation. Section 3 provides technical considerations that can guide the rationale. Where multiple technologies are identified, a technology comparison may be conducted using generic cost estimates, MVAR support ranges, and technical performance criteria to help prioritize options. Section 5 of this document provides a comparative analysis to support this evaluation.
 - **If no Alternative Technologies are Feasible:** If no ATT is deemed feasible for the stability issue, traditional transmission upgrade options should be considered. These may include reinforcement of system voltage by adding new transmission lines.
 - **Feasibility Study:** When one or more alternative technologies are identified as potentially feasible, a detailed feasibility study must be conducted to evaluate technical effectiveness and system impacts. This study should address two key questions: (1) *Can the selected technology successfully mitigate the identified violation?* and (2) *Does the selected technology introduce any new violations or adverse impacts to the system?* The modeling methodology outlined in the “**Advanced Transmission Technologies Framework**” prepared by EPE can be applied to simulate technologies performance.

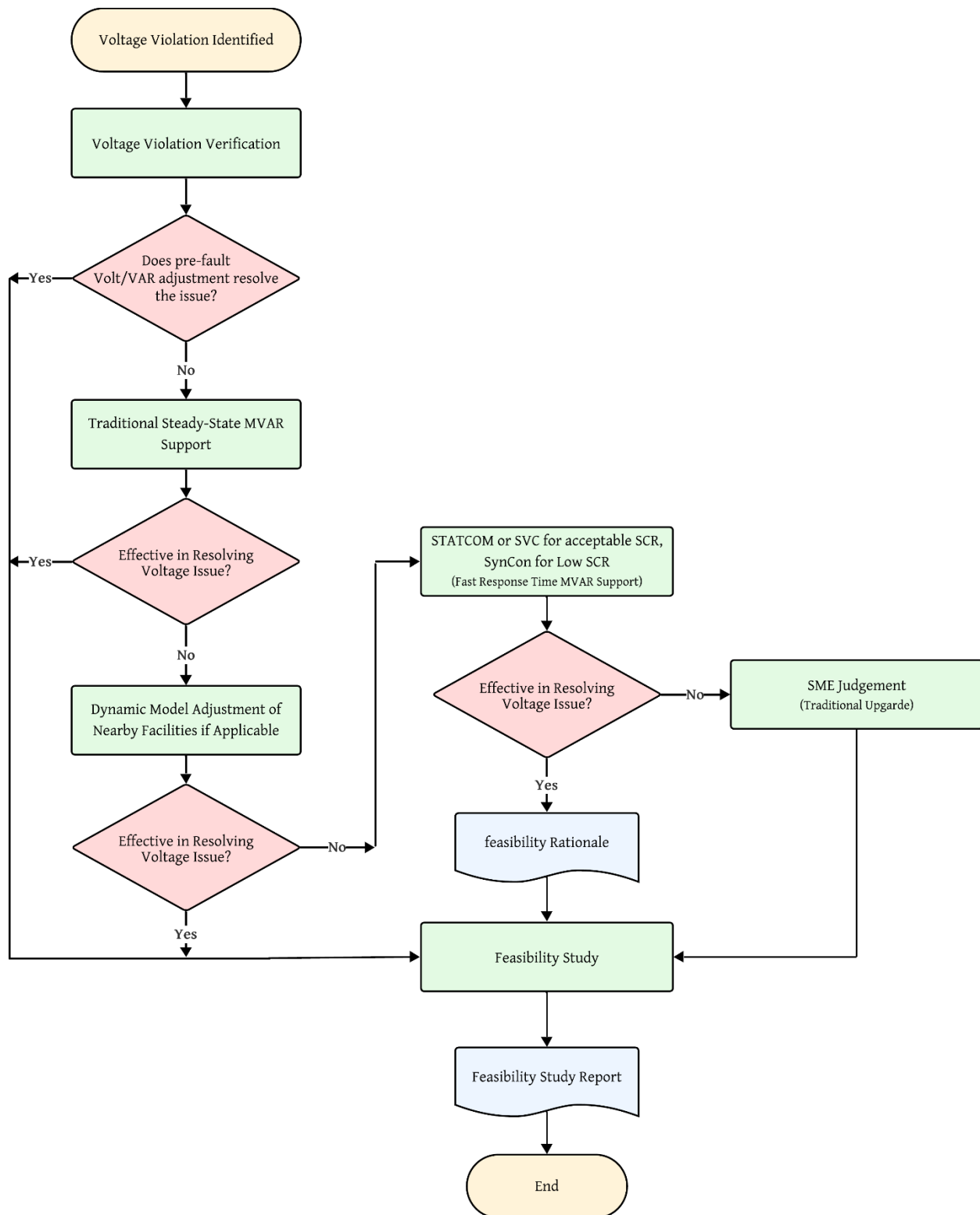


Figure 3. Stability Voltage Violation Decision Making Flowchart

5. Technology Comparison

This section provides a comparative overview of alternative technologies commonly considered for voltage violation mitigation. Table 1 summarizes the key attributes of each technology across several dimensions, including reactive power capability, response time, cost, typical voltage application range, and key technical considerations. The goal of this comparison is to aid planners and engineers in identifying suitable technology options based on system needs, operating conditions, and project constraints. While the focus of this document is on ATTs, switched shunt devices are included in the table as a conventional solution for voltage control to provide a baseline for cost, performance, and applicability comparison. This comparison supports the identification of technically and economically viable solutions, as well as the documentation of preliminary feasibility rationales for planning studies.

Switched shunt devices, such as capacitor banks and reactors, represent the most economical form of reactive power support and are widely deployed in transmission networks as a traditional voltage control measure. Their low cost and modularity make them well-suited for steady state voltage violations, particularly in systems where dynamic performance is not critical. However, due to their relatively slow response and reduced effectiveness under low voltage or dynamic conditions, switched shunts are generally not sufficient for stability-related issues. They are included here to serve as a benchmark for cost and response characteristics against advanced technologies.

SynCons provide both dynamic reactive power and rotational inertia, making them uniquely valuable in weak-grid conditions or areas with high IBR penetration. They improve voltage stiffness and short-circuit strength while supporting protection coordination. Although they require higher capital investment and maintenance compared to static devices, SynCons can be especially effective in low SCR systems or locations requiring both inertia and voltage stability.



STATCOMs offer the fastest dynamic response of all technologies considered, delivering full reactive power support within milliseconds and maintaining capability under deep undervoltage conditions. Their modular multilevel converter design allows for scalable deployment and precise control. While their capital cost is high, STATCOMs are often justified in critical areas with significant dynamic voltage sensitivity. They are most effective in systems with adequate SCR, as they do not inherently increase short-circuit strength.

SVCs provide a cost-effective balance between switched shunts and STATCOMs, offering fast reactive power adjustment and continuous voltage regulation through thyristor-controlled components. They are particularly effective in higher voltage systems with moderate stability challenges. While less modular and less effective under deep undervoltage than STATCOMs, SVCs remain a proven technology in systems with sufficient strength and moderate dynamic needs.

In combination, these technologies form a complete range of tools for mitigating voltage violations. Selection should be based on system characteristics, the nature of the violation, and cost-effectiveness, using switched shunts as a reference point and the advanced technologies as targeted solutions for more complex conditions.

Table 1. Alternative Technologies Comparison

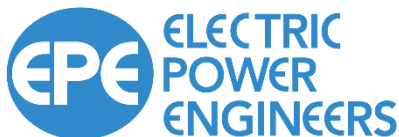
Technology	Reactive Power Source	Range (Approx.)	Response Time	Cost Estimate	Typical Voltage Level	Technical Considerations
Switched Shunt	Static	~1-150 MVAR	~0.3-3 Seconds	Low (20-30 k\$/MVAR)	69 kV-765 kV	Pros: Excellent modularity Cons: Limited response speed Ineffective under low-voltage or dynamic conditions
SynCon	Dynamic	~20-250 MVAR	~0.2-2 seconds	Medium – High (50-80 k\$/MVAR)	69 kV-345 kV	Pros: Provides inertia High fault current capability Voltage stiffness in low-SCR or high-IBR areas Cons: Higher maintenance losses Larger footprint Limited modularity
STATCOM	Static (VSC-based)	~10-400 MVAR	<10ms	High (80-150 k\$/MVAR)	69 kV-500 kV	Pros: Extremely fast dynamic response Full capacitive support under deep undervoltage Highly modular Cons: High capital cost and complexity Not suitable for low SCR areas
SVC	Static (Thyristor-based)	~50-500 MVAR	10-100ms	Medium (50-80 k\$/MVAR)	115 kV-765kV	Pros: Fast dynamic response Cons: Performance drops under deep undervoltage Less modular than STATCOM

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Advanced Transmission Technologies

Streamlining ATT Deployment Process

Presented To:

Indiana
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Commission

August 2026



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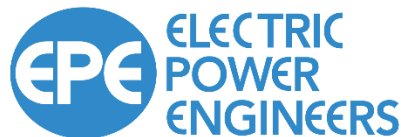
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1. Purpose and Context

The Advanced Transmission Technology (ATT) framework, thermal and voltage evaluation procedures, and associated screening tools developed in the earlier tasks provide Indiana utilities with a structured approach for identifying where ATTs may represent feasible alternatives or complements to traditional transmission solutions. These tools are intended to move ATT consideration earlier in the planning process by embedding technical feasibility, decision variables, screening criteria, and comparative assessment into a repeatable evaluation framework. Building on that foundation, Indiana utilities and regulatory stakeholders may consider extending the same structured approach beyond initial screening to the subsequent feasibility, coordination, permitting, and implementation stages.

The recommendations below are not intended to prescribe regulatory changes or create mandatory implementation requirements. Rather, they identify opportunities to make ATT evaluation and deployment more consistent, transparent, and efficient within existing utility and MISO planning processes. The recommended approach would create a clearer path from identification of an eligible ATT through increasingly detailed feasibility assessment and, where appropriate, implementation.

2. Establish a Phased ATT Feasibility and Deployment Path

Once the screening process identifies one or more potentially viable ATT options, utilities may consider advancing those options through a phased feasibility process, with the level of analysis and engineering detail increasing as the technology progresses through each phase. An initial or preliminary feasibility phase could confirm the underlying system need, verify that the ATT addresses the applicable thermal, voltage, reliability, or operational constraint, identify major fatal flaws, and develop an order-of-magnitude understanding of cost, schedule, constructability, modeling needs, and implementation risk. The Thermal and Voltage Procedures and their associated decision trees can serve as the technical starting point for this phase, while the ATT framework and technology attribute comparisons can provide supporting information on technology characteristics, limitations, expected benefits, and applicability.

ATT options that remain promising could then proceed to a more detailed feasibility phase. This phase may include refined power-flow and stability studies, technology-specific modeling, equipment and site requirements, operational considerations, vendor or engineering input where appropriate, and more refined cost and schedule estimates. The comparative cost and implementation-timeline information developed through the project may be used as a consistent reference point when comparing ATT alternatives with conventional upgrades. A final development phase could then address detailed engineering, procurement strategy, permitting, implementation planning, operating requirements, and any necessary approvals. This phased approach could help focus detailed engineering resources on the most promising alternatives while allowing other viable ATT options to be evaluated progressively as additional technical, cost, and implementation information becomes available.

3. Integrate Stakeholder Identification and Coordination into Each Phase

Stakeholder coordination may be incorporated as an explicit element throughout the phased process, with the level and scope of engagement evolving as potential solutions are evaluated and refined. At the preliminary stage, the utility could identify the asset owner, affected utility territories, neighboring systems, MISO interfaces, relevant internal utility groups, and other parties whose facilities or operations may be affected. The level of engagement could then increase as the ATT progresses through the feasibility process. For example, an advanced conductor project may require coordination among transmission planning, asset management, engineering, protection, operations, maintenance, environmental, real estate/right-of-way, and regulatory functions. Projects near another utility's territory or affecting shared or interconnected facilities may also benefit from early coordination with that utility and MISO.

A simple stakeholder-mapping step could therefore be included in the feasibility workflow to identify relevant stakeholders, clarify their roles and information needs, and determine appropriate points for engagement throughout the process. This may reduce late-stage redesign, avoid duplicated studies, and identify ownership or jurisdictional issues before significant engineering effort is committed.

4. Define Study Requirements and Modeling Expectations Earlier

ATT deployment may also be streamlined by establishing a more consistent approach for determining which studies are appropriate for each technology and project stage. The study scope could be scaled to the nature of the constraint and the maturity of the proposed solution. Preliminary screening may rely primarily on steady-state analysis and the decision variables contained in the Task 2 procedures, while later phases may add dynamic, protection, short-circuit, operational, or other technology-specific assessments as needed. Utilities may also consider documenting accepted modeling assumptions, data requirements, model-validation expectations, and approaches for representing technologies that are not yet fully supported in standard planning tools.

The best practices and lessons learned summarized in the ATT framework can be used as a reference when defining these study requirements. Establishing a repeatable study pathway may be particularly useful for technologies whose performance depends on operating conditions, controls, weather, or topology, because the feasibility assessment can explicitly capture the conditions under which the ATT provides the intended benefit and the conditions under which a conventional solution or complementary measure may still be required.

5. Incorporate Permitting, Siting, Land, and Regulatory Considerations into Feasibility

Technical feasibility alone does not determine whether an ATT can be deployed quickly. As candidate options mature, the evaluation process may include an increasingly detailed review of siting, right-of-way or land acquisition, environmental requirements, construction access, permitting, utility-specific requirements, and applicable local, state, federal, and regional regulatory processes. These considerations could initially be addressed through a high-level checklist and then refined as the project advances. The objective would not be to create new regulatory requirements, but to identify applicable requirements earlier and establish a predictable sequence for addressing them.

This approach may also help distinguish ATTs that can function as relatively rapid interim or short-term solutions from those that require permitting, land, outages, or construction activities comparable to conventional upgrades. Where an ATT can be implemented more quickly, utilities may consider evaluating it as a bridge solution while a larger transmission project is being developed, particularly where the ATT can relieve an identified constraint without precluding the long-term upgrade.

6. Create a Repeatable Decision Record and Handoff to Implementation

A streamlined process may benefit from a concise decision record at the conclusion of each phase. The record could summarize the identified system need, ATT options screened, reasons for advancing or eliminating alternatives, study results, stakeholder input, cost and schedule considerations, permitting or siting constraints, and remaining uncertainties. This would provide a consistent basis for deciding whether to stop the evaluation, perform additional analysis, compare the ATT with a traditional upgrade, or advance the concept toward implementation.

Taken together, the Task 2 framework, Thermal and Voltage Procedures, screening tools, best-practice findings, and comparative cost and timeline assessments can serve as components of a broader end-to-end ATT deployment pathway. Indiana utilities and regulators may consider using these materials not as stand-alone deliverables, but as linked references within a phased process that begins with screening and continues through feasibility, stakeholder coordination, detailed evaluation, permitting and siting review, and implementation planning. Such an approach could help make ATT consideration more routine within existing planning practices while preserving flexibility for utilities, MISO, and regulators to determine the appropriate level of analysis and coordination for each project.

Figure 1 summarizes the recommended streamlined ATT deployment process, building on the outputs of the ATT screening tool. The process provides a high-level pathway for advancing potentially feasible ATT options through phased feasibility assessment, design and permitting, deployment and commissioning, and ultimately operation. Stakeholder identification and coordination are incorporated throughout the process to support evaluation, decision-making, implementation, and ongoing operation.

ATT FEASIBILITY & DEPLOYMENT PROCESS (HIGH-LEVEL)

From Screening Tool Outputs to Turnkey Installation

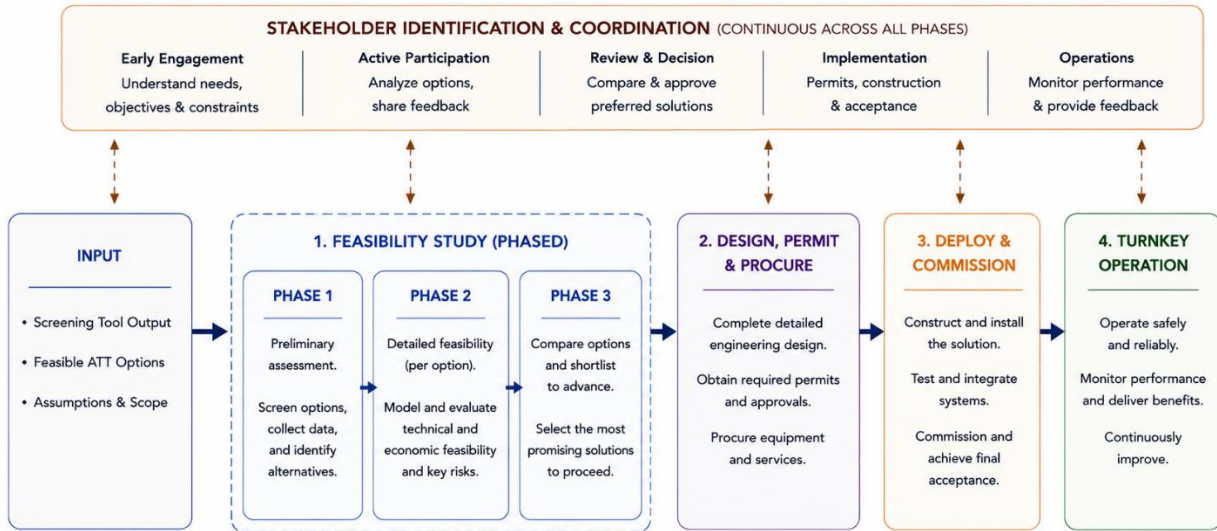


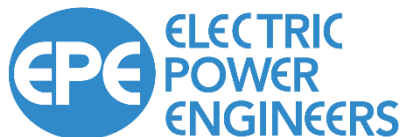
Figure 1. Recommended Streamlined ATT Feasibility and Deployment Process

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A low-angle, close-up photograph of a high-voltage electrical transmission tower. The tower's lattice structure is composed of dark metal beams, and several high-voltage power lines with insulators are visible, extending from the tower towards the top left of the frame. The background is a clear, light blue sky.

Advanced Transmission Technologies

Attribute Matrix

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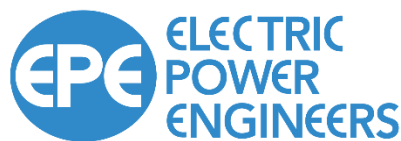
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Technology Attribute Matrix-Thermal

Technology	A. Increases Transmission Capacity	B. Increases Transmission Efficiency	C. Reduces Transmission Congestion	D. Reduces Curtailment of Generation Resources	E. Increases System Reliability	F. Increases System Resiliency	G. Increases the Capacity to Connect New Energy Generation Resources
Advanced Conductor	Yes – High. Can substantially increase line ampacity; the procedure considers overloads < 150% potentially feasible with minimal tower upgrades and 150–250% potentially feasible with tower/ROW upgrades. Above ~250%, a new line is generally more appropriate.	Yes – Moderate to High. Advanced conductors can reduce electrical losses compared with conventional conductors; DOE reports approximately 25–40% lower energy losses for advanced-conductor applications.	Yes – High. Higher transfer capability on an existing constrained corridor can relieve thermal constraints and reduce congestion, particularly where conductor ampacity is the limiting element.	Yes – Moderate to High . By increasing transfer capability across constrained corridors, advanced conductors can accommodate additional generation output that might otherwise be limited by transmission constraints. The magnitude is system- and location-dependent.	Yes – High. Provides a permanent physical increase in transmission capability and can alleviate thermal reliability constraints. DOE identifies advanced reconductoring as a potential option to support grid reliability and resource adequacy.	Yes – Moderate to High. Higher thermal capability and low-sag performance can provide additional operating margin. DOE identifies advanced-conductor deployment as a grid-resilience measure.	Yes – High. Increased corridor transfer capability can accommodate additional generation and help address transmission constraints associated with new generation interconnection, particularly when existing ROW can be reused.
Tower Lifting	Yes – Moderate to High. Most viable for loading ≤150% when ground clearance is limiting; up to ~250% may be feasible when combined with advanced conductors.	No – Not directly. Does not reduce conductor resistance or losses; primarily removes clearance/sag constraints to enable higher line loading.	Yes – Indirectly. Higher usable line rating can relieve congestion when ground clearance is the binding constraint.	Yes – Indirectly. Can reduce curtailment when generation is constrained by a clearance-limited transmission bottleneck.	Yes – Moderate. Resolves clearance-driven thermal constraints and provides a permanent increase in usable line capability but does not add a new transmission path.	Limited / Indirect. Provides additional thermal margin but does not inherently add redundancy. Implementation may also be constrained by extreme weather or height restrictions.	Yes – Indirectly. Can enable additional generation transfer when interconnection is constrained by a clearance-limited existing line .
Advanced Power Flow Controller	Yes – Moderate. Most practical for overloads up to ~ 140–150% ; higher overloads may require multiple devices, increasing cost and complexity.	Yes – Moderate. Improves utilization of existing transmission by redirecting flow from overloaded to underutilized corridors; does not inherently reduce conductor losses.	Yes – High. Directly redirects power from overloaded lines to available parallel paths, provided those paths have sufficient capacity. EPRI explicitly identifies “Congestion Reduction” as an APFC use case.	Yes – Moderate to High. By relieving transmission constraints, APFC can enable otherwise constrained generation; EPRI documents deployments that unlocked 252–400 MW of generation capacity.	Yes – Moderate to High. Controllable flow redistribution can relieve overloaded facilities and maintain reliability during contingencies/outages; however, controls and protection add operational complexity.	Yes – Moderate. EPRI identifies Operational Resilience as an APFC use case because dynamic flow control can help manage contingency events; benefits depend on available alternate paths.	Yes – High. APFC can unlock existing grid capacity through flow redistribution; DOE specifically supports APFC projects to increase transfer capacity and enable variable renewable integration .
Transmission Switching	Yes – Indirect / System-dependent. Does not increase a line’s physical rating but can increase usable network transfer capability by reconfiguring topology and shifting flow to underutilized paths.	Yes – Moderate. Can improve utilization of the existing network by finding lower-stress/lower-cost configurations; benefits depend strongly on topology and available alternate paths.	Yes – High. One of the strongest use cases: switching can reroute flow away from overloaded elements. DOE cites an SPP case where topology optimization reduced constraint flow by >20% and eliminated post-contingency overloads.	Yes – Indirectly. By relieving transmission constraints and creating alternate flow paths, switching can reduce the need for generation redispatch or curtailment; the benefit is highly system- and contingency-dependent.	Yes – Moderate to High. Can mitigate overloads and improve post-contingency performance, but every switching action must be checked to avoid creating new violations or weak/islanded conditions.	Yes – Moderate. EPRI identifies transmission switching/line switches as mechanisms that can redirect power flow and minimize outage impacts, improving system flexibility and resilience.	Yes – Indirectly. Can unlock existing network capability by relieving congestion, but it does not create new physical capacity; effectiveness depends on alternate paths and contingency performance.
Dynamic Line Rating	Yes – Moderate, weather-dependent. Best suited for ~ 110–140% of static rating ; higher gains are possible but should not be treated as firm capacity without site-specific evidence.	Yes – Moderate. Improves utilization of existing lines by replacing conservative static assumptions with actual/forecast thermal capability; it does not inherently reduce conductor losses.	Yes – Moderate to High . DOE identifies congestion management as a strong DLR benefit; better capacity forecasting can enable more efficient dispatch and reduce congestion costs.	Yes – Moderate. DLR can provide additional capacity during constrained periods and help avoid generation curtailment, especially when favorable cooling coincides with high renewable output.	Yes – Moderate. DOE states DLR can improve reliability by identifying true thermal limits, avoiding overload-related outages, and increasing situational awareness.	Yes – Moderate. DOE explicitly identifies improved reliability and resilience through enhanced situational awareness and greater operational flexibility.	Yes – Moderate. DLR can unlock existing transmission capacity and support renewable interconnection, but the available capacity is weather-dependent and not firm.

Technology Attribute Matrix-Voltage

Technology	A. Increases Transmission Capacity	B. Increases Transmission Efficiency	C. Reduces Transmission Congestion	D. Reduces Curtailment of Generation Resources	E. Increases System Reliability	F. Increases System Resiliency	G. Increases the Capacity to Connect New Energy Generation Resources
STATCOM	Moderate — Dynamic reactive support can improve voltage profiles and voltage stability limits, allowing existing transmission facilities to support higher loading where voltage, rather than thermal rating, is the limiting constraint. EPRI specifically evaluates STATCOMs for increasing transmission capacity on existing AC assets.	Moderate — By dynamically controlling reactive power and bus voltage, STATCOMs can improve power factor/voltage profiles and may reduce system losses. However, efficiency improvement is a secondary benefit rather than the primary purpose of a STATCOM.	Low to Moderate — STATCOMs do not directly reroute active power like APFCs or transmission switching. They can relieve voltage-constrained transfer limitations and thereby indirectly reduce congestion but have limited benefits when congestion is purely thermal.	Moderate — Fast dynamic voltage support can improve fault ride-through and allow generation to remain connected during voltage disturbances.	High — STATCOMs provide fast dynamic reactive power and voltage regulation, supporting transient voltage recovery and maintaining acceptable voltage performance. This directly aligns with NERC's objective of maintaining voltage and reactive resources within limits for reliable, interconnected operation.	Moderate to High — Their rapid response can help the system withstand and recover from severe voltage disturbances. However, unlike synchronous condensers, STATCOMs do not inherently provide rotational inertia or substantial synchronous fault current.	Moderate to High — STATCOMs can facilitate IBR interconnection in weak or voltage-constrained areas by providing dynamic reactive support and improving low-voltage performance/fault ride-through. The benefit is especially important where voltage stability or reactive capability limits additional interconnection.
SVC	Moderate — Dynamic reactive power and voltage support can increase usable transfer capability where voltage stability or reactive power is the limiting factor. EPRI specifically identifies “increase the transmission capacity” as one of the main reasons for applying SVCs in transmission systems.	Moderate — SVCs regulate voltage and reactive power dynamically, which can improve voltage profile and reduce reactive-power-related transmission losses. EPRI explicitly lists reduction of transmission losses as an SVC application;	Low to Moderate — SVCs do not directly control active-power routing, so they are much less direct than APFC or transmission switching for congestion management. However, by increasing voltage/stability-constrained transfer capability, they can indirectly relieve congestion when the binding constraint is voltage-related	Low to Moderate — SVCs can improve transient voltage recovery and help generation remain connected during voltage disturbances but does not directly reduce generation curtailment.	High — This is one of the strongest attributes. SVCs provide fast-acting reactive support, respond within cycles, support transient recovery, and can damp oscillations and limit voltage excursions.	Moderate — SVCs improve the ability to withstand voltage disturbances and power swings, but they do not inherently add synchronous inertia or substantial fault-current strength. They may be less effective in severely low-SCR systems, where STATCOMs or Synchronous Condensers are preferred.	Moderate — SVCs can provide dynamic reactive support needed for connecting new generation or large loads where voltage regulation is a constraint.
Synchronous Condensers	Moderate — Synchronous Condensers provide dynamic reactive power and voltage support, which can increase usable transfer capability when the system is limited by voltage stability or weak-grid conditions.	Low — Synchronous Condensers are not primarily an efficiency technology and consume real power for losses.	Low to Moderate — Synchronous Condensers do not directly reroute active power and therefore are not congestion-control technology.	Moderate — By strengthening voltage performance, short-circuit strength, and disturbance ride-through in weak-grid areas, Synchronous Condensers can reduce the likelihood that generation must trip or be restricted for stability reasons.	High — This is one of the strongest Synchronous Condenser attributes. They provide dynamic reactive power, short-circuit current, and rotational inertia, and are particularly effective in weak-grid/low-SCR areas.	High — Synchronous Condensers provide multiple physical grid-strength services simultaneously: voltage support, inertia, synchronizing torque, and fault current.	High — Synchronous Condensers can be particularly valuable for integrating new inverter-based resources in weak areas because they restore grid attributes that may diminish as synchronous generation retires.