Project 1A: Application to Artificial Island Area System Performance

Artificial Island Project 1A Review

Dominion High Voltage

DNV GL Energy Americas

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1 Executive summary

On 29 April 2013, PJM Interconnection (PJM) opened a proposal "window" seeking proposals to mitigate limitations affecting the Artificial Island (AI) area of New Jersey. Twenty-six projects were proposed by seven entities. PJM selected ten ("Selected Ten") of these 26 proposals based on relative costs.

One of these entities was Dominion High Voltage Holdings, Inc. (DHV), which proposed three projects. One DHV project, "Project 1A", is based on a new 500 kV switching station close to the existing 500/230 kV New Freedom substation, approximately 35 miles northeast of AI.

DHV engaged DNV GL Energy to independently review the suitability of Project 1A as a solution to the AI problems identified by PJM.[1] This report presents the results of our review. In short, we found that:

1. PJM determined that Project 1A can meet all the planning criteria set out for the AI problem (see §4.1, page 29);
2. PJM's results show that Project 1A has better stability performance than the Selected Ten projects with lower swing-angles and better reactive output margins (Table 5, page 29);
3. Project 1A has much lower costs than the other proposed projects (§4.2, page 30):
   - The Selected Ten projects have total costs between $296 million and $526 million, while
   - Project 1A costs $155 million;
4. Project 1A can be completed much sooner than the Selected Ten projects (§5.1.1, page 33):
   - PJM's Selected Ten projects all cross the Delaware River and would take at least eight years or longer to approve and build, while
   - Project 1A can be approved and built in less than three years;
5. Project 1A will likely receive the greatest public acceptance and the least regulatory review (§5.1.2, page 34):
   - All the Selected Ten projects include an interstate crossing of the Delaware River—a major navigable waterway, and between 3 and 17 miles of new overhead transmission, while

1. Also participating in the review was Dr. Gregory F. Reed, Director of the Electric Power Initiative and the Electric Power Systems Laboratory in the Swanson School of Engineering at the University of Pittsburgh.

- Project 1A requires a site of only about five acres, needs no new overhead (or underground) transmission and has minimal visual impact;

6. Project 1A has lower risks for both misoperation and construction mishaps on the AI site than the Selected Ten projects (§5.1.3, page 35):
   - The Selected Ten projects require significant reconfiguration, additions, or changes at the Salem or Hope Creek 500 kV substations, while
   - Project 1A requires only limited changes at the Hope Creek substation;
7. Project 1A uses equipment and components with decades-long records of reliable performance in utility power system applications (§3.1.3, 3.1.4, and 3.2.4, pages 17,18, and 23).

1.1 Proposed project features

1.1.1 PJM Selected Ten projects

1.1.1.1 Delaware River crossing

As mentioned above, all the Selected Ten projects cross the Delaware River. Seven of the Selected Ten projects have new overhead river crossings. Five of these have new 3-mile overhead river crossings along with 17 miles of new overhead transmission (projects 4A, 5B, 2C, 1C, and 7K). The other two have new 4-mile overhead river crossings and 3 miles of new overhead transmission (5Aovh and 1B). The remaining three of the Selected Ten projects have new 4-mile submarine river crossings along with 3 miles of new overhead transmission (5Asub, 2B, and 2A).

1.1.1.2 AI substation reconfigurations

Nine of the Selected Ten projects require reconfiguring the Salem 500 kV substation (4A, 5Aovh, 5B, 2C, 1B, 7K, 5Asub and 2A). The reconfigurations include various combinations of building new substation bays, relocating existing transmission connections, or installing a new 500/230 kV transformer. The other Selected Ten project (1C) requires building a new bay at the Hope Creek 500 kV substation.

1.1.2 DHV Project 1A

DHV's Project 1A would build a new five-acre 500 kV switching station near the existing New Freedom 500/230 kV substation. A static var compensator (SVC) would be included at the new switching station and a thyristor-controlled series capacitor (TCSC) would be connected into each of two of the existing circuits between AI and New Freedom (circuits 5023 and 5024). The SVC supports and stabilizes voltage following certain faults, and the TCSCs rapidly reduce the effective electrical distance between the New Freedom and AI following fault clearing. An important reason for DHV's proposing both an SVC and the TCSCs is that they can respond very quickly, and their output can be modulated.

The proposed SVC monitors the 500 kV voltage and varies its output as necessary to support and regulate the 500 kV voltage. The TCSCs use power electronics to provide impedance control and line regulation. When needed, the TCSCs will make the new switching station appear to be about 4 miles from AI rather than the actual 40-50 mile line lengths. This significantly improves the effectiveness of the SVC following faults on or near AI.

The basic components of the SVC and TCSCs are the same. Both devices include: power electronics; inductors that provide negative vars; capacitors that provide positive vars; and associated circuit breakers and buswork.

These components have been widely used in the electric power industry, including PJM, for decades. They have excellent reliability records and are accepted by utilities and various government agencies and regulatory bodies. Series capacitors have been used by US utilities for transmission compensation since at least the 1970s. Shunt reactors have been widely used for even longer. The power electronics have been used in HVDC converters as well as SVCs, TCSCs and other FACTS applications for over 40 years.

1.2 Proposed project costs

PJM selected 10 of the 26 proposals with the lowest costs; ranging from $296 million to $526 million. All of PJM's Selected Ten projects share at least one common feature—a new transmission "outlet" circuit from AI that crosses the Delaware River. DHV's Project 1A does not include a new transmission outlet but has much lower costs than those in PJM's Selected Ten list.

PJM adjusted the original Selected Ten cost estimates following consultation with various equipment manufacturers and the work of an outside consultant. To meet PJM planning criteria, PJM found that an SVC must be added to all the Selected Ten projects. DHV Project 1A includes an SVC that PJM found would meet planning criteria when its size was increased somewhat.

Since a new SVC will be needed with any of these choices, the SVC cost will be a part of all the project costs. The business decision before PJM then becomes: what is the remaining project cost for each of the proposed projects? PJM estimated the SVC cost to be at least $80 million. Removing this common SVC cost component from all the projects gives the remaining project cost for each of the projects as shown in Table 1.

Table 1: Remaining project costs after removing common SVC costs

	Project cost ($M)										
		PJM Selected Ten projects									
Cost estimate	1A	4A	5Aovh	5B	2C	1B	1C	7K	5Asub	2B	2A
PJM adjusted cost Low High	155	296 343	313 363	301 349	312 362	313 363	323 374	329 384	328 382	337 393	446 526
Less common SVC cost	80	80	80	80	80	80	80	80	80	80	80
Remaining cost Low High	75	216 263	233 283	221 269	232 282	233 283	242 294	249 304	248 302	257 313	366 446

The cost advantage of Project 1A is very clear—the next least expensive project (4A, low) has nearly three times the remaining cost of Project 1A; and the most expensive (2A, high) has nearly six times the remaining cost.

1.3 Proposed project risks

The proposed DHV Project 1A offers a number of beneficial characteristics that mitigate various technical, cost, and licensing and approval risks when compared to the Selected Ten projects as summarized in Table 2.

All the projects use conventional equipment and meet the planning criteria set forth by PJM—they will all work acceptably. Eight of the Selected Ten projects have some increased risk associated with reconfiguring the Salem substation. In general, the technical risks for all the projects are smaller than the licensing and approval risks.

These regulatory risks are in getting approval and the various opportunities for delays and modification as part of the licensing and approval processes. Project 1A has the least environmental impact, will be the easiest to get approved, and will be the fastest to construct and put in operation. Finally, it is, by far, the least costly.

Table 2: Comparison of risks

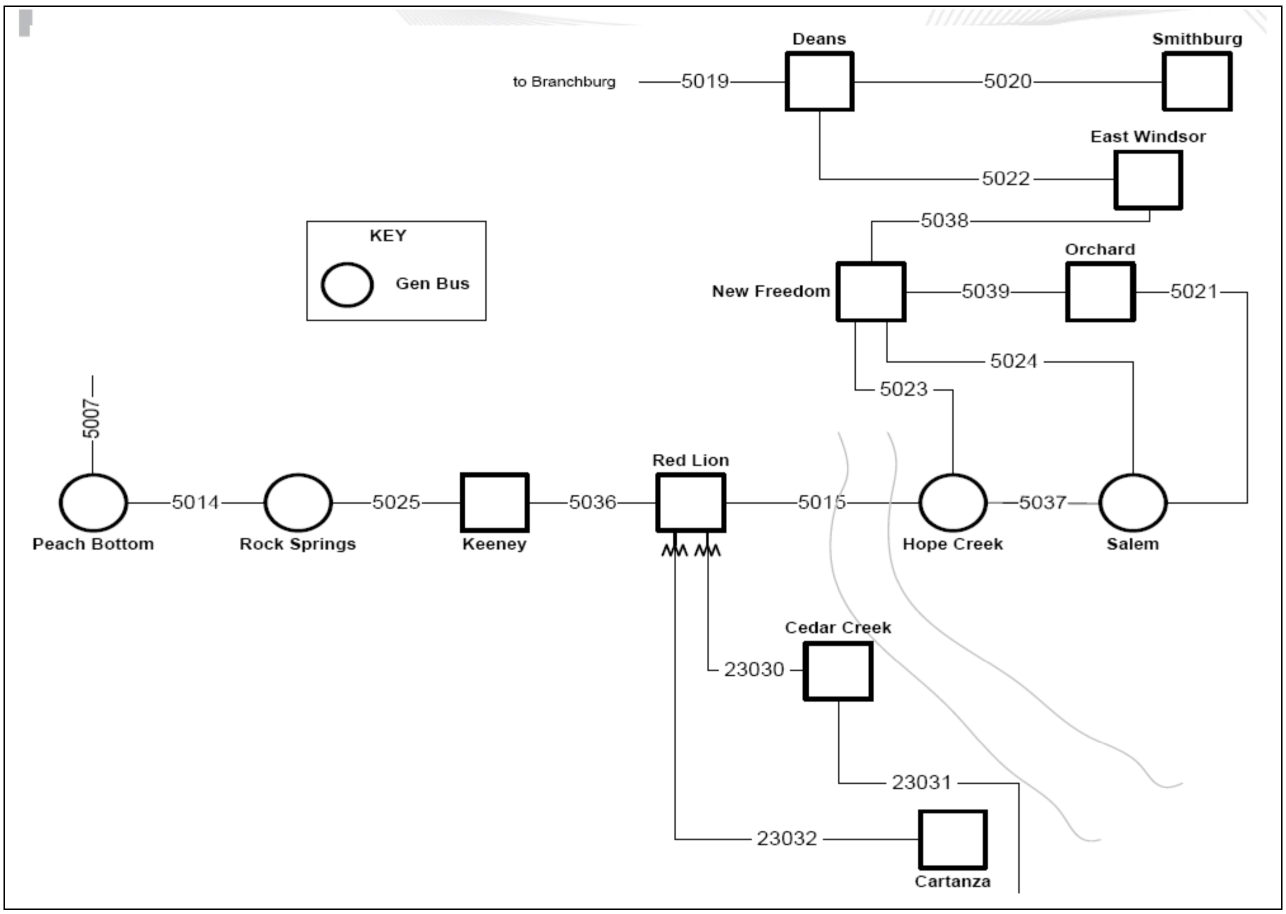
Technical risks	Cost risks	Licensing and approval risks
Planning criteria—The Selected Ten projects and Project 1A meet all the planning criteria established by PJM for the AI analysis. Licensing, approval and construction times—Project 1A can be completed at least five years earlier than any of the Selected Ten projects. This will remove today's risk of cross-tripping Salem nuclear units. Component reliability—circuit breakers, relaying, and the components of the SVC and TCSCs have decades of reliable operating experience. These devices have comparable relaying design and equipment failure risks. Substation construction/reconfiguration—opens a risk of possible mishaps during construction and errors in relaying, etc. Some projects will require longer outages/curtailments at Salem for substation work. Project 1A, in contrast, makes no equipment changes at Salem and only limited changes at Hope Creek Cross-tripping of Salem nuclear units—Project 1A will remove this risk at least five years earlier than the Selected Ten projects.	The incremental cost of Project 1A is only a third of the cost of the next-lowest cost project. Being able to build Project 1A at least five years sooner than any of the Selected Ten projects allows it to obtain savings from improved market efficiency.	River crossing—the Selected Ten projects include an interstate river crossing that will likely cause long delays. The submarine-crossing projects will be approved more quickly. The river crossing may also raise objections from shipping and other business interests. Project 1A does not include a river crossing. Visual impact—generally generates the most public opposition. The Selected Ten projects with a northern crossing have 17 miles overhead transmission, while those with a southern crossing have 3 miles overhead. Project 1A needs no new transmission lines. Transmission right of way—the northern-crossing projects cross wetlands that could cause some delays or difficulties in getting right of way approved. Project 1A does not require any transmission right of way. Agency approvals required—the number of approvals and agencies required will affect the risk of delays and increased costs. All the Selected Ten projects require review by multiple Federal, New Jersey and Delaware agencies because of the river crossing, overhead transmission and significant substation work at the AI nuclear plant substations. Project 1A has minimal land use and little impact on substations.

2 Background

2.1 PJM request for proposed technical solutions

On 29 April 2013, PJM Interconnection (PJM) opened a proposal "window" seeking proposals for technical solution alternatives to mitigate limitations affecting the Artificial Island (AI) area of New Jersey.[2] The AI area transmission network and generation facilities are shown in Figure 1.[3] The system includes 500 kV and 230 kV transmission facilities, and the Salem and Hope Creek nuclear generation facilities.

Figure 1: Artificial Island area transmission network



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2. *PJM RTEP – Artificial Island Area Proposal Window Problem Statement & Requirements Document*, CEII Redacted, PJM Interconnection, original document: 29 April 2013, version 14.0 revised: 16 May 2013.

3. PJM Transmission Expansion Advisory Committee, 8 May 2014 presentation, page 35.

The AI area now experiences operating limitations and, in future, will likely violate PJM, North American Electric Reliability Organization (NERC), Reliability First Corporation (RFC), and local transmission owner planning criteria under certain conditions and contingencies. These operating limits and criteria violations may be based on facility thermal ratings, transient stability limits, voltage stability limits, or system voltage limits. In addition, the limits and criteria violations may be based on applicable pre- and post-contingency system or facility ratings.

PJM's objectives were, among others, to;

- Allow maximum output of the Salem and Hope Creek generating plants under normal and various contingency conditions;
- Reduce operating complexity;
- Improve AI stability; and
- Maintain present system operating limits.

PJM's request specified 27 specific breaker fault and 13 line outages conditions that should be studied, making 355 contingency combinations. Of these, 81 violated criteria or did not meet performance standards.[4]

2.2 Proposed technical solutions

The AI proposal window "closed" on 28 June 2013. Twenty-six projects were proposed by seven entities—three of these were made by Dominion High Voltage Holdings, Inc. (DHV).[5, 6]

2.2.1 PJM-selected projects for further review

Costs for the 26 proposed projects ranged from $123 million to $1.5 billion. PJM adjusted these cost estimates following consultation with various equipment manufacturers and the work of an independent consultant. PJM then selected ten of the proposals ("Selected Ten") with the

4. *Artificial Island Area Proposal 1, 500 MVAR SVC plus Two Thyristor Controlled Series Compensation (TCSC) Devices* [redacted public version], Dominion Virginia Power, 26 June 2013, Page 6.

5. PJM Transmission Expansion Advisory Committee, 10 July presentation, page 67.

6. The DHV proposals were initially submitted by its affiliate Virginia Electric & Power Company, a pre-qualified Transmission Owner within PJM. Subsequent to its pre-qualification, DHV was identified as the entity proposing the technical solutions.

lowest revised costs; ranging from $216 million to $446 million.[7] A lower-cost proposal submitted by DHV, Project 1A, was not included. The original and PJM-revised costs for these projects are shown in Table 3.

Table 3: Original and PJM-adjusted costs for lowest-cost projects

	Project cost ($M)										
		PJM top-ten projects									
Estimate	1A	5Aovh	4A	5B	2C	1B	1C	7K	5Asub	2B	2A
Original	133	116	181	171	123	133	199	297	148	165	213
Revised											
Low	155[8]	233	216	221	232	233	242	249	248	257	366
High		283	263	269	282	283	294	304	302	313	446

All of PJM's Selected Ten projects share at least one common feature—a new transmission "outlet" circuit from AI that crosses the Delaware River. Five of them connect to the existing 230 kV transmission circuits in Delaware—what PJM calls southern crossings. The other five are northern crossings that connect to the 500 kV Red Lion substation in Delaware.

Two of these ten (Projects 1B and 1C) were southern crossing projects proposed by DHV. DHV's third proposal (Project 1A) was discussed, but not included in the PJM's Selected Ten list.

2.2.2 DHV Project 1A—SVC and TCSC

The main components of DHV's proposed Project 1A included a static var compensator (SVC) and two thyristor-controlled series capacitors (TCSC).[9] The SVC and TCSCs would be connected through a new 500 kV switching station close to the existing 500/230 kV New Freedom substation. This new 500 kV switching station would be connected into 500 kV circuits 5023 and 5024. These two circuits enter the New Freedom substation on the same right-of-way which will facilitate their connection to the new substation.

7. PJM Transmission Expansion Advisory Committee, 10 April 2014 presentation, pages 46-7; and PJM Transmission Expansion Advisory Committee, 19 May 2014 presentation, pages 211

8. As discussed on page 6, below, PJM increased the size of the proposed SVC. The revised cost is based on estimates by DHV of $22 million for this increase.

9. *Artificial Island Area Proposal 1, 500 MVAR SVC plus Two Thyristor Controlled Series Compensation (TCSC) Devices* [redacted public version], Dominion High Voltage, June 26, 2013.

The overall configuration of the proposed switching station is represented in Figure 2. The figure shows both how the new switching station will connect into the existing system and a representation of the internal connection of the circuits, buses and breakers.

Figure 2: New switching station overview

[redacted]

DHV estimated the cost of Project 1A to be $133 million. PJM adjusted the cost estimates for the Selected Ten projects as discussed above. These adjustments reflected PJM's increased cost estimates for submarine cable, 500 kV aerial transmission, 500/230 kV transformers and the cost for an aerial Delaware River crossing.[10] None of these apply to DHV's Project 1A.

An important reason for using both an SVC and the TCSCs is that they can respond very quickly and their output can be modulated. The thyristor power electronics can respond and provide full output within one or two cycles. With the SVC, the output can swing from positive to

10. PJM Transmission Expansion Advisory Committee, 10 April 2014 presentation, pages 43-5.

negative Mvar just as quickly and can reverse flows repeatedly. With both the SVC and TCSCs the power electronics can vary the output between any level from zero to maximum.

2.2.2.1 SVC operation

DHV's proposed new SVC would be +750 Mvar to -250 Mvar at this new 500 kV switching station. While DHV's original proposal was for a +500 Mvar SVC, PJM found that Project 1A performed acceptably only when the SVC capacity was increased to +750 Mvar.[11]

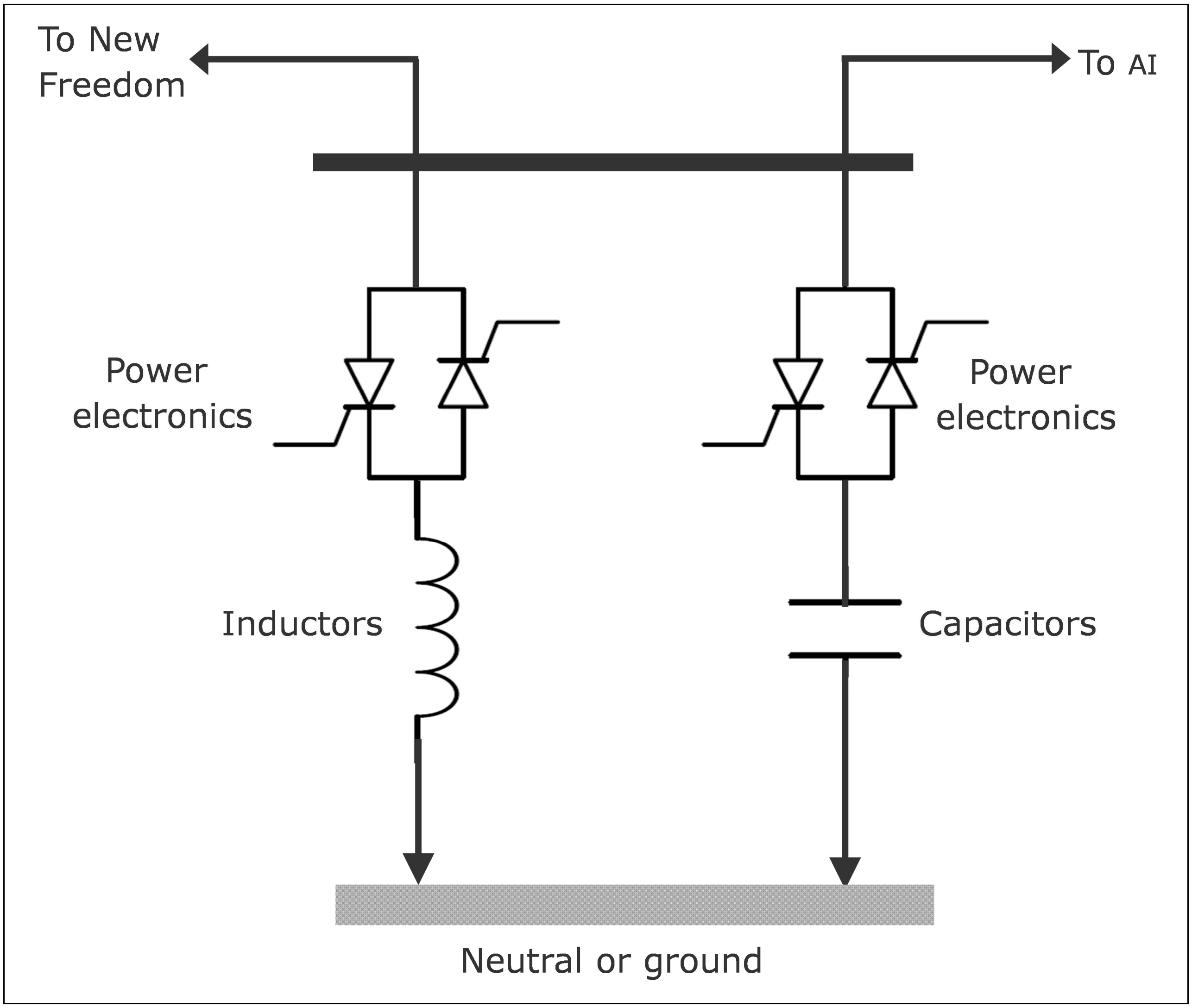
The proposed SVC would be connected to both 500 kV circuits running between AI and New Freedom—5023 and 5024—as shown in Figure 2.

A simplified representation of the internal configuration of the SVC is shown in Figure 3.[12] The SVC is connected in parallel between the common 500 kV bus in the new switching station and neutral (ground). The main internal components are inductors and capacitors that provide the negative and positive vars and the power electronics to control the vars.

11. PJM Transmission Expansion Advisory Committee, 11 December 2013 presentation, page 48.

12. Adapted from en.wikipedia.org/wiki/Static_var_compensator.

Figure 3: Representation of internal SVC configuration



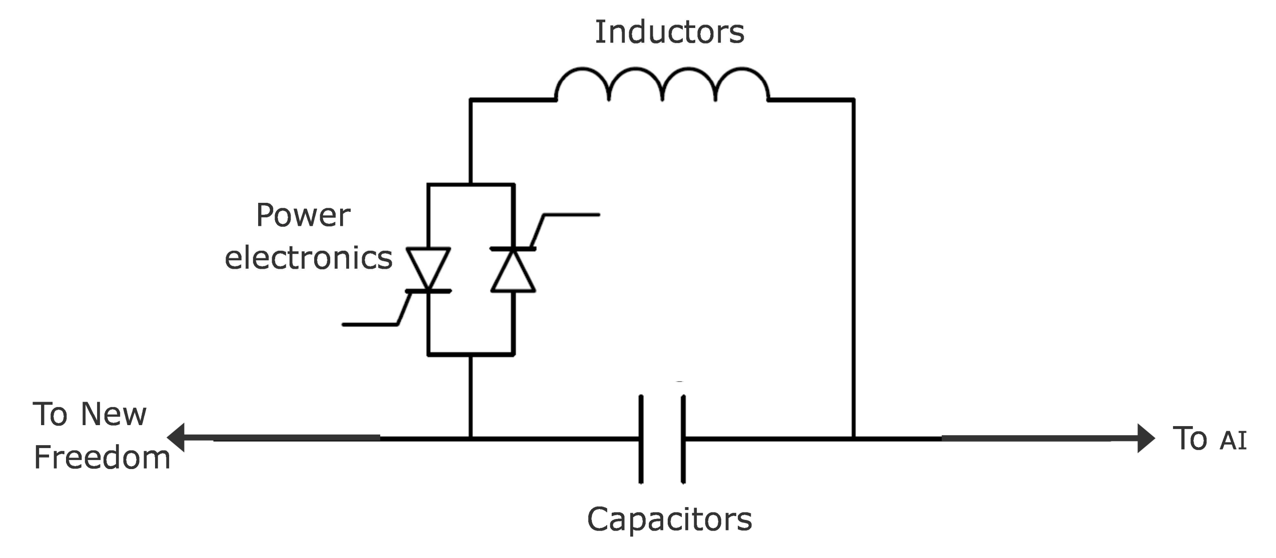
The proposed SVC operates based on the local bus voltage independently from the TCSCs. The SVC will respond to the 500 kV voltage at the new switching station. Immediately following a fault condition, the SVC reacts dynamically to boost the low voltage by injecting positive or negative vars as necessary to control the voltage. The flexibility of the associated power electronic controls allows the svc to dampen voltage oscillations.

2.2.2.2 TCSC operation

The TCSCs would be connected in series with lines 5023 and 5024 close to the New Freedom substation as shown in Figure 2. A simplified representation of the internal configuration of the

TCSCs is shown in Figure 4.[13] The TCSCs are connected in series with the circuits between AI and New Freedom so they can control the reactive impedance of these circuits. The main internal components are the same as with the SVC—inductors and capacitors and the power electronics to control the impedance of the line.

Figure 4: Representation of internal TCSC configuration



The TCSCs operate based on the current flowing in the AI–New Freedom circuits independently from the SVC. The TCSC activates within three cycles of fault clearing. It then acts as a switch, allowing the compensation to rise to 90%. After 2.5 seconds, the TCSC switches back to normal compensation—either 40% or 45%.

In the proposed installation, the modulating capability of the TCSC is not being used. In fact, if there were conventional breakers that could reliably operate fast enough, a TCSC would not be needed. In this sense, this application is the simplest form of TCSC use in that no modulation is needed and all the controls are local.

13. Adapted from *Artificial Island Area Proposal 1, 500 MVAR SVC plus Two Thyristor Controlled Series Compensation (TCSC) Devices* [redacted public version], Dominion High Voltage, June 26, 2013, page 5.

3 Technology involved

3.1 The SVC

A static var compensator (SVC) is a power electronics based system that is used to provide fast-acting, dynamic reactive power compensation on high voltage electric transmission networks. SVCs are part of the flexible alternating current transmission system (FACTS) family of technologies that are connected to the power system and are implemented for regulating voltage, power factor, and harmonics on power systems, as well as for providing system stabilization, increased power capacity, and power flow control.

3.1.1 Components and configuration

SVC systems and installations consist of three main building blocks:

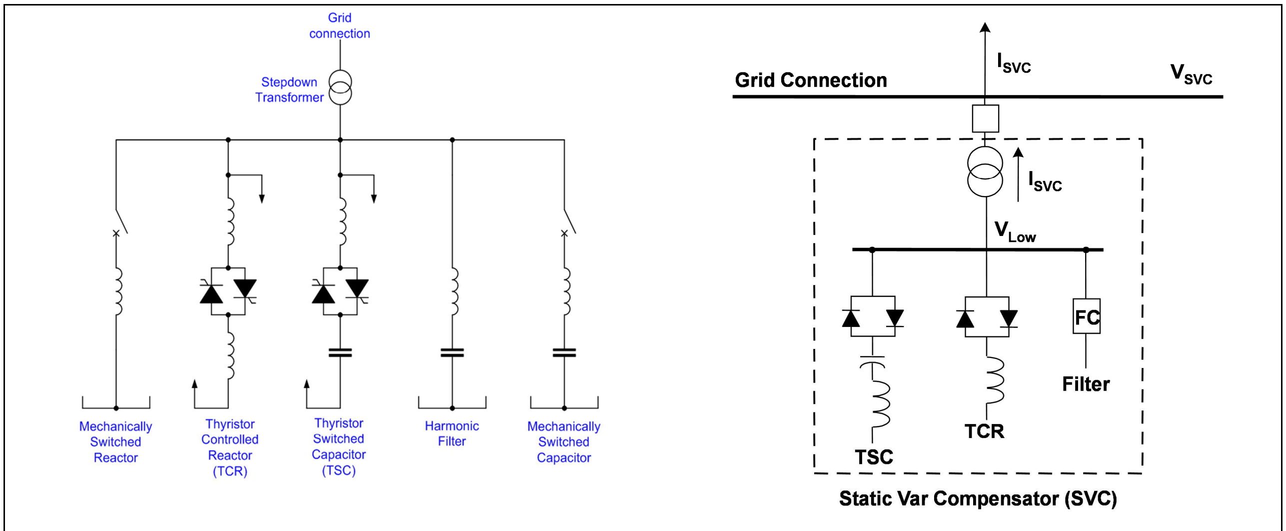
1. Thyristor valves;
2. Air core alternating current (AC) reactors; and
3. High voltage AC capacitors

The most important is the thyristor valve (i.e., stack assemblies of series connected anti-parallel thyristors to provide dynamic controllability). The thyristor valves and their associated control system, together with auxiliary systems, such as relaying and system protection, valve cooling system controls, SCADA interface, and other hierarchical controls, are located inside an SVC building. The air core reactors, capacitors, and harmonic filters together with the power transformer, associated switchgear, and cooling system heat exchangers and fans are located outdoors.

Air core AC reactors and high voltage AC capacitors are the reactive power elements used together with the thyristor valves. The thyristor controlled reactors (TCRs) and thyristor switched capacitors (TSCs) are normally coupled with fixed capacitive filters (FCs) for controlling harmonic generation produced by the thyristor valve operation. Mechanically switched capacitors and reactors (MSCs and MSRs) can also be incorporated as part of any SVC system configuration. The equipment's step-up connection to the transmission voltage is achieved through a power transformer.

A one-line diagram of an SVC design arrangement that would include all of the various types of branches listed above is show in the left-hand part of Figure 5. Most SVC’s in operation, however, typically consist of combinations of TCRs, TSCs and capacitive harmonic filters, as show in the right-hand side of Figure 5.

Figure 5: Typical one-line diagrams of SVC



Configuration and types of branches Typical SVC design configuration

3.1.2 SVC operation

The SVC is a dynamic source of reactive current with a sub-cycle reaction time—on the order of tens of milliseconds. Using the thyristor valve as fast-acting switches, the AC capacitor banks (TSCs) can be switched in and out rapidly as a stepped var source based on the size of the capacitors being switched. Also, the thyristor valves can, by means of phase-angle modulation, continuously control the current through an air core reactor (TCRs) providing a smoothing operation of the system's var output. This combination of switching capacitors and controlling reactors provides a continuous, smooth control of the reactive current output between two extremes set by the size of the components selected.

SVC's utilizing phase-angle control of reactors will produce current harmonics (of odd orders). In order to avoid excessive harmonic distortion in the transmission grid, such SVC's have internal harmonic filters that act as sinks for the harmonic currents. These filters also provide part of the required capacitive capability and are normally connected to the system at all times.

SVC's in transmission applications are most often used to control the voltage at the bus where they are connected. The voltage control is typically a closed loop, three-phase symmetrical voltage control with a set droop that allows the voltage to vary a few percent. Each SVC's capacity and voltage interconnection rating is typically unique to the specific application it is designed for. Multiple branches of TSCs and TCRs are often incorporated for larger capacity systems and for design redundancy as it may be dictated by a particular end-users specification.

3.1.3 SVC applications and benefits

Applications of SVC technology are wide-ranging. Many of the typical or traditional applications of the technology include:

- Improving voltage stability (which, in general, constitutes the majority of SVC applications),
- Enhancing overall transmission system reliability and control by providing dynamic voltage control
- Improving power system stability,
- Enhancing power quality and system security, and
- Increasing power flow control.

Applications for utility bulk transmission systems, industrial (such as arc furnace flicker control), and transportation (such as railway voltage stabilization) operations have been deployed and in-service since the early 1970s. Thus, there is a large experience base for the application and operation of SVC technology across various sectors of the electrical supply chain.

A recent trend has seen SVCs applied for fault-induced voltage recovery as a result of the rapid decommissioning of many older fossil-fueled generation plants located near large load centers. The loss of such generation depletes local dynamic reactive power capability, as well real power supply. Many SVCs in the U.S. and abroad have been deployed in recent years specifically for this situation.

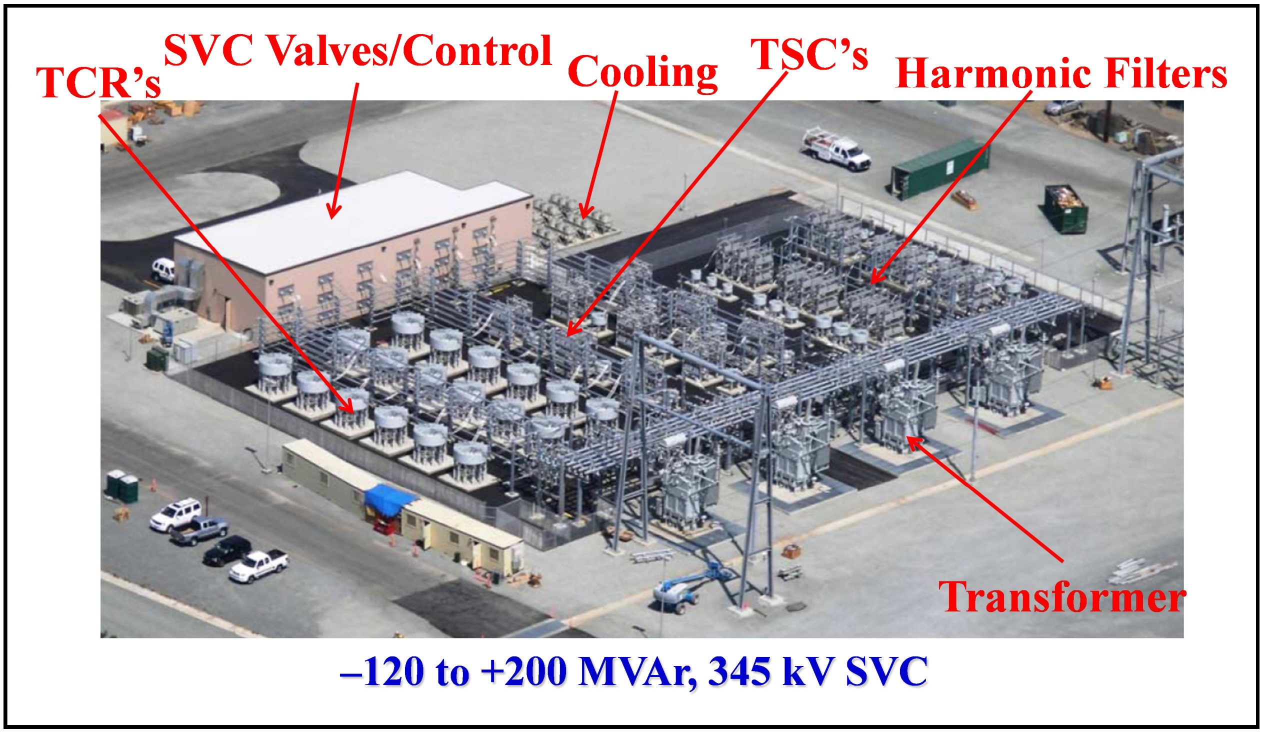
As renewable energy penetrations increase, applying SVCs is important for supporting voltage fluctuations due to inherent renewable energy variability and intermittency, as well as providing interconnection stability.

With more applications and plans for high voltage direct current (HVDC) systems in the U.S. and abroad as a means to expand and upgrade transmission infrastructure, SVCs are often used at either or both ends of an HVDC system, in order to provide dynamic voltage regulation, especially on a weak AC side of an HVDC terminal.

As other trends in the power industry continue to evolve, such as an increase in distributed energy resources at the distribution voltage level and more deployment of microgrid concepts, SVCs will continue to provide value for these emerging applications as well.

Figure 6 shows a photo of a 345 kV transmission level application of an SVC rated at -120 Mvar inductive to +200 Mvar capacitive.

Figure 6: 345 kV SVC installation implementing TSCS, TCRS, and FCS



3.1.4 SVC experience

Today there are nearly 1,500 SVCs in operation worldwide, since the first in 1970, consisting of installations by major vendors such as ABB (over 500), Alstom/Areva/GE (approx. 400), Mitsubishi/TMEIC (approx. 200), and Siemens (approx. 200), as well as other vendors. The total installed Mvar capacity of these installations is tens of thousands of Mvar.

In the U.S. alone, there are approximately 200 applications of SVCs, since the first in 1972, totaling thousands of Mvar. Recent 500 kV SVC projects within the PJM footprint have been implemented by FirstEnergy and DHV affiliate Virginia Electric & Power Company in Pennsylvania, Virginia and West Virginia.

3.2 The TCSC

A thyristor controlled series capacitor (TCSC) is a power electronics based system that is applied to provide fast-acting, dynamic reactive-impedance compensation on high voltage electric transmission networks. TCSCs, like SVCs, are part of the FACTS family of technologies. TCSCs are connected in series with a transmission line to regulate voltage and impedance on power systems to provide power flow control.

3.2.1 Components and configuration

TCSC systems and installations consist of the same building blocks as SVCs.

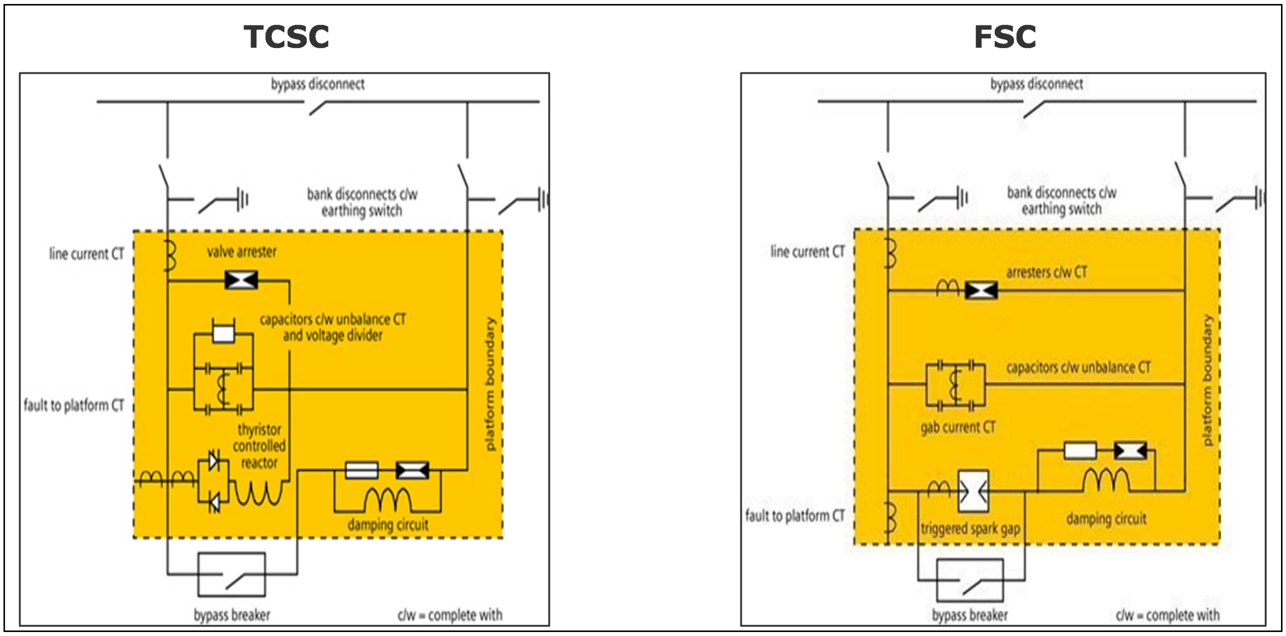
- As with the SVC, the most important is the thyristor valve (i.e., stack assemblies of series connected anti-parallel thyristors to provide dynamic controllability), and
- Air core AC reactors and high voltage AC capacitors (the reactive power elements) that are used together with the thyristor valves, to provide the impedance regulation.

A TCSC also includes a metal-oxide varistor (MOV) that is connected across the capacitor to prevent overvoltage. In general, TCSC configurations include controlled reactors in parallel with sections of a series capacitor bank. The combination allows for smooth control of the fundamental frequency of capacitive reactance over a wide range.

All of the power equipment is located on an isolated steel platform, including the thyristor valve stack that is used to control the behavior of the main capacitor bank. The control and protection systems are located at ground potential inside a control building. Other auxiliary systems such as the valve cooling system controls, SCADA interface, and other hierarchical controls are also at ground potential in the control building. The air core reactors, capacitors, associated switchgear, and cooling system heat exchangers and fans are located outdoors.

A simplified one-line diagram of a TCSC design arrangement was shown in Figure 4 on page 13, above. A more detailed one-line of the TCSC and fixed series capacitor (FSC) configurations are shown in Figure 7. The TCSC closely resembles the conventional FSC from a technology perspective. The FSC one-line diagram is shown with the TCSC one-line in Figure 7 to illustrate the similarities. The main difference is that the TCSC provides a thyristor-based dynamically controlled reactor, and therefore provides variable impedance control and line regulation as compared to the FSC. The building blocks are otherwise the same, and the TCSC valves are essentially the same as those of an SVC.

Figure 7: Detailed one-line diagram of TCSC and FSC configuration and main components



3.2.2 TCSC operation

There are two main features of the TCSC operation:

1. The TCSC provides electromechanical damping between portions of the electrical power system by changing the reactance of a specific power transmission line. That is, the TCSC will provide a variable capacitive reactance.

2. The TCSC changes its apparent impedance (as seen by the line current) for sub-synchronous frequencies, such that a prospective sub-synchronous resonance is avoided.

Both of these are achieved with the TCSC using control algorithms that work concurrently. The controls function on the thyristor circuit (which is in parallel to the main capacitor bank and in series with the controlled reactor) such that controlled charges are added to the main capacitor, making it a variable capacitor at fundamental frequency, but a "virtual inductor" at sub-synchronous frequencies. Through the thyristor-based control, this manipulation of line reactance can be performed dynamically for power flow control and other applications.

Depending on the specific application, 100% of the TCSC capacity (which is usually provided in terms of percent of reactive compensation and/or in Ohms) can be placed on either end of the transmission line, in the middle or anywhere along the line.

3.2.3 TCSC applications and benefits

Typical applications of TCSC technology are to control the line impedance to provide maximum power transfer capability across the line, and to limit any potential of sub-synchronous resonance. This most commonly applies on long transmission lines but applies to lines of any length.

Series compensation, in general, has been successfully utilized for many decades in electric power networks. With series compensation, it is possible to increase the transfer capability of existing power transmission systems at a lower cost and with a shorter installation time compared to building new lines. Series capacitors are used to reduce circuit impedance to increase dynamic stability of power systems, improve voltage regulation and reactive power balance, improve load sharing between parallel lines, and to boost transmission system capacity.

Using TCSC technology provides a number of important benefits for transmission system applications as compared to conventional series compensation. The benefits include eliminating sub-synchronous resonance risks, damping active power oscillations, improving post-contingency stability, and effecting dynamic power flow control. These all relate to the speed and variability of the thyristor controls. Most TCSC applications result in increased power transfer capability associated with the controlled transmission line. It is also possible for the thyristor control to be applied to existing conventional FSC installations, by upgrading them to all or partial TCSC capability.

By controlling power flow on the transmission line with TCSC technology, it is possible to obtain minimal system losses, reduce parallel-path flows, eliminate line overloads, optimize load sharing between parallel circuits/corridors, and direct power flows along contractual paths. By damping power oscillations, TCSCs offer improved operations by reducing or eliminating the impact of oscillations than can be caused by line faults, switching disturbances, or sudden changes in interconnected generation output, especially under heavy loading conditions.

Using TCSCs for controlling dynamic stability has been recognized for decades. A 1996 Cigré paper describes how TCSCs "may be used as a means for adapting the loadability of certain critical lines that would risk to be operating with too large angle separation or amplitude deviations during contingencies."[14] The paper also notes that TCSCs can be utilized to improve the power system performance by providing additional damping of electromechanical oscillations or to temporarily increase the degree of compensation to alleviate the voltage drops in nodes that do not have sufficient reactive power support in case of contingencies.

TCSCs can also adjust their degree of compensation quickly, which is very helpful in improving post-contingency network operation. Such speed allows TCSCs to rapidly change the series capacitive compensation temporarily following contingencies on the power system and improve dynamic stability, for both voltage and angle, precisely when needed.

Using TCSCs to eliminate sub-synchronous resonance (SSR) is another major benefit of the technology. This application of TCSCs provides compensation for poorly damped torsional vibration frequency of turbo-generator shafts that can induce mechanical stresses on the generation equipment. The TCSC for SSR applications helps to eliminate the risk of coinciding resonant frequencies by allowing the series capacitor to act inductive in the sub-synchronous frequency range.

Figure 8 shows a photo of an extra high voltage (EHV) application of a TCSC.[15] Note how much smaller the installation is with a TCSC as compared to an SVC as shown in Figure 6. The size difference is especially important regarding the valves. The valves in the TCSC are a much smaller physical component than they are in the SVC. An SVC has larger thyristor stacks because the thyristors must handle the full voltage (e.g. 500 kV) of the connection, whereas with a TCSC they must only handle the fraction of that voltage that is across the series capacitor. In the SVC the valves and controls are in a fairly large three-story building (Figure 6). In the TCSC they are on an elevated, insulated platform, and only 10-15 feet tall (Figure 8).

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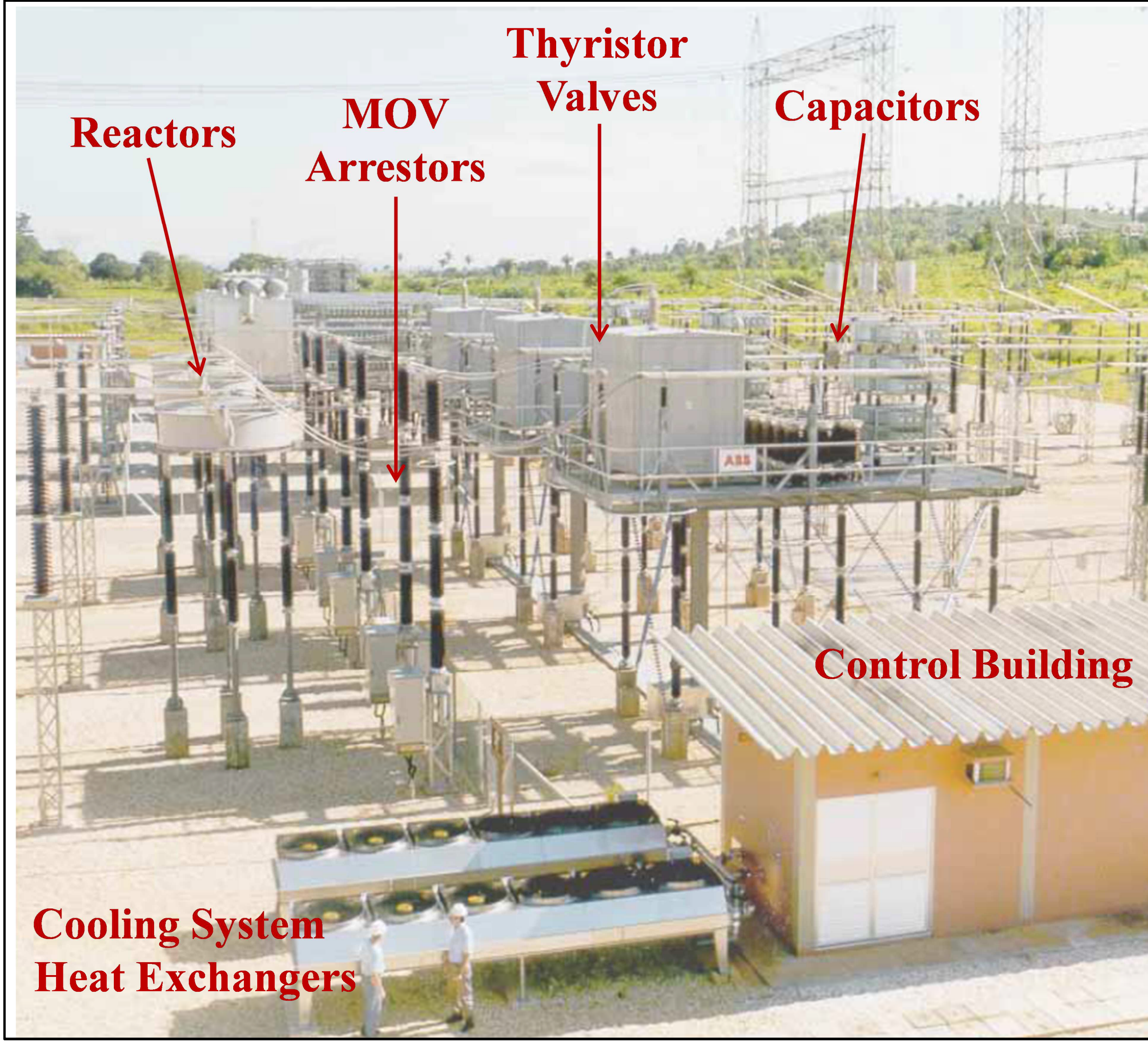
14. Ängquist , Lennart, Gunnar Ingeström, Hans-Åke Jönsson, *Dynamical Performance of TCSC Schemes*, Cigré 1996 Session, paper 14-302.

15. The specific application is at 400 kV, rated at 40% degree of compensation with 395 Mvar of capacitive reactive power.

Figure 8: 400 kV TCSC rated at 40% compensation



3.2.4 TCSC experience

There are three common types of TCSC applications used worldwide:

1. For sub-synchronous resonance (SRR) mitigation,
2. To provide post-contingency transient stability, and
3. For dynamic flow control.

Some examples of TCSC applications are shown in Table 4 dating from 1992 and as recently as this year.

Table 4: Examples of TCSC applications

Year	Country	KV	Appliction: SSR mitigation	Appliction: Post-contingency stability	Appliction: Dynamic flow control	Location	Source
1992	USA	230			✔	Kayenta substation, AZ	1, 2
1993	USA	500	✔		✔	C.J.Slatt substation, OR	1
1998	Sweden	400	✔			Stöde	1, 3
1999	Brazil	500	✔	✔		Imperatriz and Sarra de Mesa	1, 4
2002	China	500	✔	✔		Pinguo substation, Guangzhou	1
2004	India	400	✔	✔		Raipur substation	1, 5
2004	China	220	✔	✔		North-West China	1
2014	United Kingdom	400	✔	✔	✔	Hutton substation	6

Notes:

1. Maruf, Nasimul Islam, et.al. , *Study of Thyristor Controlled Series Capacitor (TCSC) as A Useful Facts Device*, International Journal of Engineering Science and Technology, Vol. 2(9), 2010, pages 4357-4360.
2. Jalali, J. and R. Hedin, *Thyristor Controlled Series Compensation (TCSC) Impedance and Linearized Models for Power Swing and Torsional Analysis*, Electric Power research Institute, May 1988.
3. Holmberg, D., et. al., *The Stöde Thyristor Controlled Series Capacitor*, Cigré 1998 Session, Paper 14-105.
4. Grünbaum, R. and Jacques Pernot, *Thyristor-Controlled Series Compensation: A State of The Art Approach for Optimization of Transmission Over Power Links*, ABB Power Systems, 2001.
5. *North – South 500 kV AC power interconnection: transmission stability improvement by means of TCSC and SC India*, ABB FACTS brochure, 2011.
6. *ABB's FACTS Solution to Facilitate Increased Power Flow from Scotland to England*, ABB UK, 2014.

As the table shows, there are examples of TCSC use in all three types of applications. These examples are most often at transmission voltages of 400 kV and 500 kV. (***These are in the same voltage class as the proposed 500 kV Project 1A.***) The most common application is for SSR mitigation. Applications to maintain post-contingency stability are also common. This is the type of application that is being used with Project 1A.

These example TCSCs have provided reliable service over their lives. This is the same experience as the industry has had with SVCs. This is not surprising since both TCSCs and SVCs use the same equipment.

The SVCs (and TCSCs) that are being built today are designed to meet availability levels of 99%. Historically, these systems have met or exceeded the availability guarantees for nearly all installations. Similarly, in terms of reliability, the vast majority of the devices in operation today were designed to meet typical forced outage guarantees of less than 4 per year. These systems have also met or exceeded these reliability requirements.

3.3 Complementary operation of SVC and TCSC

The basic components of the SVC and TCSC are the same. Both devices include:

- Thyristor power electronics and associated controls providing very rapid response and variable control of current flow;
- Power inductors that provide negative vars;
- Power capacitors that provide positive vars; and
- Various circuit breakers and buswork.

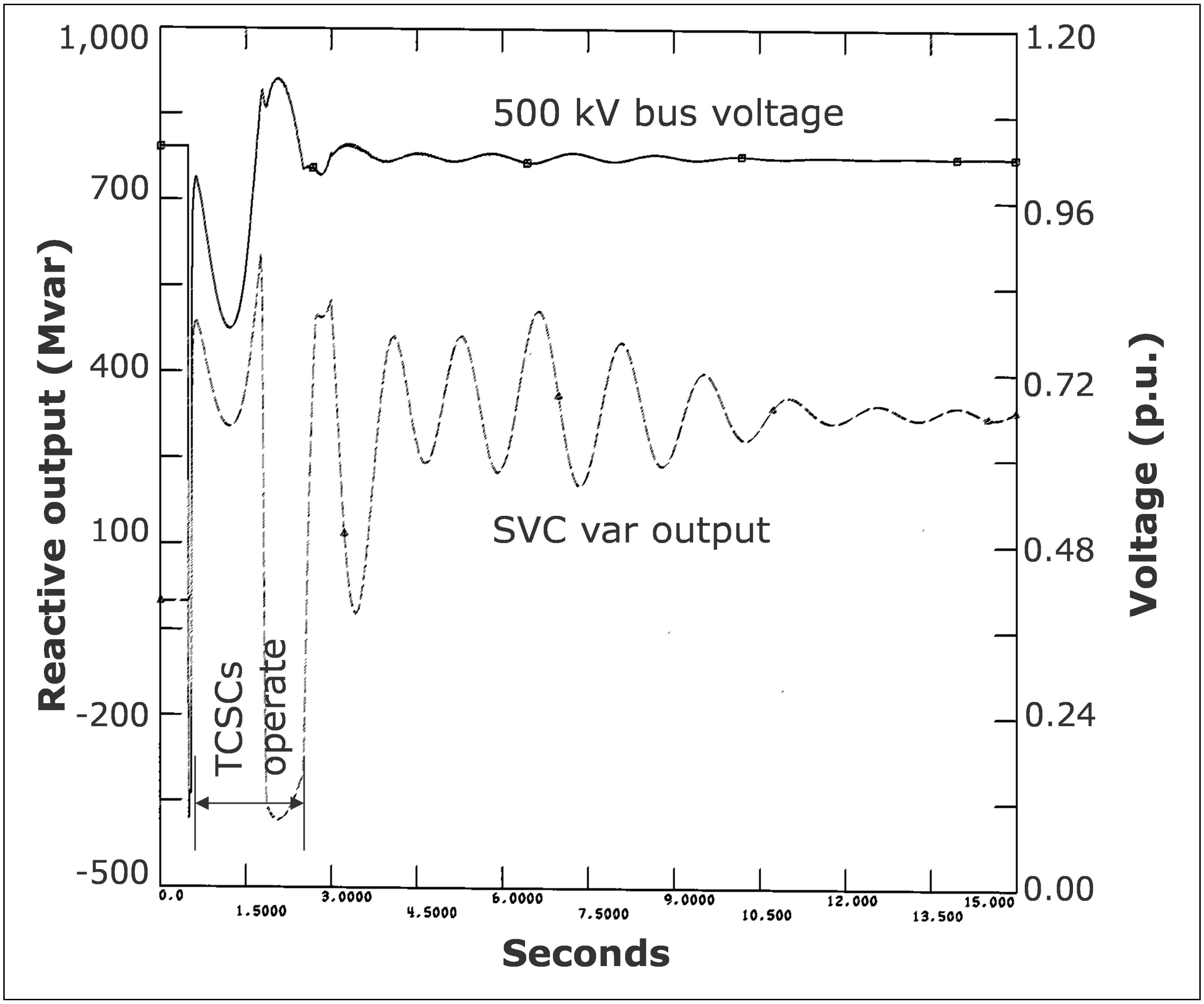
These are components that have been widely used in the electric power industry for decades. Series capacitors have been used by US utilities for transmission compensation since at least the 1970s. Shunt reactors have been widely used for even longer. The power electronics have been used in HVDC converters as well as SVCs, TCSCs and other FACTS applications for over 40 years. They have excellent reliability records and are accepted by utilities and various government agencies and regulatory bodies.

The proposed SVC operates based on the New Freedom 500 kV bus voltage independently from the TCSCs. The SVC will respond to the 500 kV voltage —when the voltage falls during a fault condition, the SVC reacts to boost the voltage by injecting up to +750 Mvar. The SVC varies its output as necessary to support and control the 500 kV voltage. An example of its response to a fault can be seen in Figure 9.[16]

The figure demonstrates the SVC's capability to respond rapidly and to modulate its output as needed to support and control the bus voltage. The figure shows the SVC almost instantly going to maximum positive output for the first second following fault clearing. As the voltage then recovers and rises above 1.0 p.u., the SVC reverses its output to maximum negative for about another second. Its output then varies to dampen the ensuing voltage swings. During the entire event the SVC responds to the bus voltage and is independent of the actions of the TCSCs.

16. Provided by DHV.

Figure 9: Proposed SVC output and voltage following a fault



The proposed TCSCs include both static and dynamic components. The proposal includes static series compensation of 40% (line 4023) and 45% (line 5024) that would be in-service at all times. This is supplemented by dynamically controlled series compensation that would bring the total compensation to 90% on both circuits. When activated, 90% compensation reduces the impedances of the AI–New Freedom 500 kV circuits to 10% of their normal levels. In effect, the TCSCs will make the New Freedom substation appear to be 4 to 5 miles from Salem and Hope Creek rather than the actual 40-50 miles.[17]

17. AI to New Freedom distance estimated from Google Earth.

Reducing the series impedance effectively connects AI more tightly to the rest of the PJM 500 kV network in New Jersey. It also significantly improves the effectiveness of the SVC when faults occur on AI.

The TCSCs monitor and respond to very high power flows following fault clearing on their respective circuits. The sudden large power flow increase will see them deliver full (90%) compensation within three cycles of fault clearing. They will operate for 2.5 seconds and then return their pre-fault state (40% and 45%) series compensation.

The approximate period of TCSCs' operation is shown in Figure 9. During the 2.5 seconds the TCSCs operate, they reduce the effective impedance of the circuits then return to normal.

4 Performance and cost demonstrated in PJM studies

During the review and stakeholder comment period following the receipt of the proposals, PJM performed various technical and cost analyses. Many of these bear on DHV Project 1A.

4.1 Technical performance in PJM studies

PJM reviewed the technical performance of DHV Project 1A. PJM found that with the SVC size increased to +750 Mvar from the originally-proposed +500 Mvar the Project passed all the testing criteria.[18] Proposal 1A meets all the minimum thermal and stability criteria requirements.

One of the metrics PJM uses to compare the stability performance of the projects is the maximum swing angle of the AI generators with the various projects under the worst contingency for each project. The maximum swing angle PJM found for each project is shown in Table 5.

Table 5: Maximum swing angle of 1A and Selected Ten projects

Project	AI 500 kV bus voltage	AI Mvar output	Critical		Maximum swing angle	Source
			Outage	Contingency		
1A +750 Mvar SVC*	1.029	645	5038	2a	88	1
1C + SVC♦	1.041	675	5015	2b2	99	2
2C + SVC♦	1.041	670	5015	14b2	101	2
4A + SVC♦	1.041	669	5015	14b2	102	2
5B + SVC♦	1.040	667	5015	14b2	102	2
1B + SVC♦	1.041	674	5015	14b	110	3
2B + SVC♦	1.042	662	5015	14b	109	3
2A + SVC♦	1.042	658	5015	14b	112	3
5A + SVC♦	1.041	721	5015	14b	112	3
7K + SVC♦	"In progress"					2

Notes:
- * SVC located at new switching station near New Freedom 500 kV as per Project 1A.
- ♦ SVC located at New Freedom 500 kV.
1. PJM Transmission Expansion Advisory Committee, 11 December 2013 presentation, page 47.
2. PJM Transmission Expansion Advisory Committee, 11 December 2013 presentation, page 54.
3. PJM Transmission Expansion Advisory Committee, 19 May 2014 presentation, page 204.

18. PJM Transmission Expansion Advisory Committee, 11 December 2013 presentation, page 48.

4.2 Costs from PJM studies

As discussed in §2.2.1 on page 8, above, PJM selected ten of the proposals with the lowest adjusted costs; ranging from $216 million to $446 million (though they did not include DHV's Project 1A).[19] PJM's adjustments reflected PJM's increased cost estimates for submarine cable, 500 kV aerial transmission, 500/230 kV transformers and the costs for an aerial Delaware River crossing.[20] None of these apply to DHV's Project 1A.

The original DHV Project 1A proposal was for +500 Mvar, -250 Mvar SVC and TCSCs with an estimated cost of $133 million. PJM found that the SVC needed to be enlarged to +750 Mvar. DHV estimated the additional cost of the larger SVC to be about $22 million, bringing the total cost to $155 million. PJM also found that all the Selected Ten projects would need an $80 million SVC to meet planning criteria.

The original and PJM-adjusted costs, including the required svc costs, for these projects are shown in Table 6.

Table 6: Revised total costs for lowest-cost projects

	Project cost ($M)										
		PJM Selected Ten projects									
Estimates cost	1A	4A	5Aovh	5B	2C	1B	1C	7K	5Asub	2B	2A
Original cost	133	181	116	171	123	133	199	297	148	165	213
Adjusted cost											
Low		216	233	221	232	233	242	249	248	257	366
High		263	283	269	282	283	294	304	302	313	446
SVC cost	22[21]	80	80	80	80	80	80	80	80	80	80
Total cost											
Low	155	296	313	301	312	313	323	329	328	337	446
High		343	363	349	362	363	374	384	382	393	526

19. PJM Transmission Expansion Advisory Committee, 10 April 2014 presentation, pages 46-7 and PJM Transmission Expansion Advisory Committee, 19 May 2014 presentation, pages 211.

20. PJM Transmission Expansion Advisory Committee, 10 April 2014 presentation, pages 43-5.

21. As discussed on page 6, above, PJM increased the size of the proposed SVC. The revised cost is based on estimates by DHV for this incremental increase.

The result is that DHV Project 1A is about half the cost of the next-lowest cost project—Project 4A at $296 million with PJM's low estimate. In total, the other projects are 1.9 times (4A low) to 3.4 times (2A high) the cost of DHV Project 1A's cost.

Since PJM found that an SVC will be needed with any of these choices, the SVC cost will be a part of all the project costs. The SVC cost then becomes a kind of "sunk cost". The business decision before PJM then becomes: "What is the remaining project cost for each of the proposed projects?"

PJM estimated the SVC cost for the Selected Ten projects to be at least $80 million. Removing this common cost from all the projects gives the remaining project cost required for each project. These results are shown in Table 7. This provides a better cost comparison for the business decision before PJM.

Table 7: Remaining project costs after excluding SVC costs

	Project cost ($M)										
		PJM Selected Ten projects									
Estimated cost	1A	4A	5Aovh	5B	2C	1B	1C	7K	5Asub	2B	2A
PJM total cost											
Low	155	296	313	301	312	313	323	329	328	337	446
High		343	363	349	362	363	374	384	382	393	526
SVC cost adjustment	-80	-80	-80	-80	-80	-80	-80	-80	-80	-80	-80
Remaining cost											
Low	75	216	233	221	232	233	242	249	248	257	366
High		263	283	269	282	283	294	304	302	313	446

The cost advantage of Project 1A is even greater in this comparison. Specifically, the next least expensive project (4A, low) is 2.9 times the cost of Project 1A; and the most expensive (2A, high) is 5.9 times the cost.

5 Benefit in mitigating risk

The proposed DHV Project 1A offers a number of beneficial characteristics that mitigate various technical, cost, and licensing and approval risks when compared to the Selected Ten projects. These are discussed below.

5.1 Project 1A risk reduction highlights

5.1.1 Risks affecting completion time

One of the most compelling advantages of DHV Project 1A is that it will be in-service much sooner than any of the Selected Ten projects, because:

- It requires only minimal land—about five acres—and DHV has identified two acceptable sites within about three miles of the New Freedom substation. The sites are zoned for residential use and are not in environmentally sensitive areas.
- The visual impact of the new substation will be minimal—no more so than a typical 500 kV substation. While the equipment will be different than a typical 500 kV substation, none of the equipment would be taller than normal and no more visible.
- Since both proposed sites are adjacent to the existing 500 kV lines, there will be no transmission right-of-way or siting issues to address.
- The TCSCs and SVC will be built with modular equipment on a single site, greatly facilitating equipment transport and construction.
- It requires only limited substation work at the Hope Creek substation (doubling two breakers), and no substation work at the Salem substation.
- The necessary changes at the New Freedom, Hope Creek and elsewhere can be completed during either normal substation maintenance or during a generator refueling outage.

Considering all the uncertainty factors, the Selected Ten projects will require at least eight years to be completed because they all include a Delaware River crossing. DHV Project 1A, by contrast, should be completed in less than three years with little opposition.

5.1.2 Risks from environmental, regulatory uncertainties and public opposition

The Selected Ten projects all face many environmental, regulatory uncertainties, not to mention public opposition that Project 1A will avoid:

1. All the Selected Ten projects
   - Involve crossing the Delaware River—no small task.
     - The lines must cross over (or under) a navigable waterway—the Delaware River. The river serves the Ports of Philadelphia, Camden-Gloucester, Paulsboro, and Wilmington, and Delaware City Refinery. Highlighting its importance, the main shipping channel is now being deepened from 40' to 45' by the U.S. Army Corps of Engineers in a $334 million, five-year effort.[22]
     - The Army Corp of Engineers, among others, must approve any of the river-crossing projects. While overhead crossings will likely be more problematic, even the submarine options will disrupt river traffic during their installation. Further there are special issues associated with properly burying the submarine cables under the shipping channel
     - In crossing the river, the Selected Ten projects will involve the public utility commissions and other state agencies in both New Jersey and Delaware. This will complicate the regulatory process, extending the overall schedule and providing two set forums for public opposition..
   - There will be some degree of public opposition to any of the projects.
     - The greatest objections are likely to come from those that are most visible—the overhead crossings and the Red Lion projects that have 17 mile overland sections.
     - The Red Lion projects all cross wetlands.
     - Even the submarine options will have three-mile overhead sections in Delaware wetlands.
2. In contrast, Project 1A has faces none of these uncertainties.

22. US Army Corp of Engineers— www.nap.usace.army.mil/Missions/Factsheets/FactSheetArticleView/tabid/4694/Article/6559/delaware-river-main-channel-deepening.aspx.

5.1.3 Risks from substation/transmission reconfiguration

All the Selected Ten projects involve transmission outlets from AI. These will require some degree of reconfiguration work at Salem/Hope Creek. Specifically, these changes will introduce risk during construction and add many relaying changes to the new and existing protection equipment. These all represent increased risk of misoperation. It is not uncommon for significant disturbances, and even local area blackouts, to occur following maintenance or construction.

Nine of the Selected Ten projects require reconfiguring the Salem 500 kV substation (4A, 5Aovh, 5B, 2C, 1B, 7K, 5Asub and 2A). The reconfigurations include various combinations of building new substation bays, relocating existing transmission connections, or installing a new 500/230 kV transformer. The other Selected Ten project (1C) requires building a new bay at the Hope Creek 500 kV substation.

PJM notes that substation expansion at Salem will present certain specific difficulties.[23] The Salem substation is space-constrained, and the access to the control house is also limited. Eight of the Selected Ten projects require significant changes at the Salem substation. (Projects 1C and 7K make changes at Hope Creek but not at Salem.) Some of these substation changes will be significant and involve constructing new breaker bays and relocating existing transmission circuit entrances.

Project 1A, by comparison, has only limited changes at Hope Creek (breaker doubling) and requires no equipment changes at Salem.

5.1.4 Today's AI risks

Whatever the risks with the proposed projects, they should be considered in the context of the types of risks that exist at AI today. These include conventional risk of transmission and substation faults and equipment failures (e.g. breakers, relays, etc.).

In addition, there are the restrictions and limitations described in PJM Manual 03. Manual 03 describes the PSE&G Artificial Island Stability cross-trip scheme—a special protection scheme (SPS) intended to maintain AI stability.[24] This describes the cross trip relay scheme at Salem used

23. PJM Transmission Expansion Advisory Committee, 19 May 2014 presentation, pages 183-190.

24. PJM Manual 03: *Transmission Operations*, Revision: 44, Effective Date: November 1, 2013. Pages 293-5.

during an extended outage of either line 5015 Red Lion-Hope Creek or line 5038 New Freedom-East Windsor. The scheme is designed to trip a Salem unit if there is an operation of the New Freedom-East Windsor (5038) line relays or if both 5038 500 kV breakers open at New Freedom or at East Windsor.

In addition, AI generator stability limits are set that may limit maximum gross MW output levels. The limits can change depending on:

- Number of units operating,
- Cross-trip relay scheme status,
- Unit stabilizer status (for Salem #1, Salem #2, and Hope Creek #1),
- Gross Mvar output levels, and
- Transmission outages.

These are all risks that the AI area now faces—all of which will be removed once any of the new AI projects are completed. Approving Project 1A will allow this to occur at least five years sooner.

5.2 Summary

Consider how each of the three main types of risk—technical, cost, and licensing and approval—affects the various projects:

1. Technical risks
    - Planning criteria—all the Selected Ten projects (including Project 1A) meet all the planning criteria established by PJM for the AI analysis.
    - Licensing, approval and construction times—Project 1A can be built and operational at least five years earlier than any of the Selected Ten projects. This will remove today's risk of cross-tripping Salem nuclear units. In addition, the Selected Ten projects face the risk of being delayed years more.
    - Component reliability
        - Conventional circuit breakers and relaying have decades of reliable operating experience.
        - Similarly, the FACTS components of the SVC and TCSCs have been used for decades with proven reliable performance.

- Both conventional and FACTS devices have comparable risks related to relaying design and equipment failure. There is little difference in the risk between them.

- Substation construction/reconfiguration—opens the risk of possible mishaps during construction and errors in relaying, etc., and some projects will require longer outages/curtailments of the Salem generation due to substation work.
    - Eight of the Selected Ten projects require reconfiguring the Salem substation that has significantly limited expansion space.
    - Projects 1C and 7K require reconfiguration changes at Hope Creek.
    - Project 1A, in contrast, makes no equipment changes at Salem and only minimal changes at Hope Creek
- Cross-tripping of Salem nuclear units—is armed under various conditions and would be avoided with all the projects. Project 1A, alone, will allow this risk to be removed at least five years earlier than the Selected Ten projects.

2. Cost risks
    - The incremental cost of Project 1A is only a third of the cost of the next-lowest cost project.
    - Being able to build Project 1A at least five years sooner than any of the Selected Ten projects allows it to obtain savings from improved market efficiency.
3. Licensing and approval risks
    - River crossing—is likely to be the most challenging to get approved and is likely to cause the longest delays
        - All the Selected Ten projects include a river crossing, though the submarine-crossing projects will probably be approved more quickly than the overhead-crossing projects.
        - Because this involves a major navigable river it may also raise objections from shipping and other business interests.
        - Project 1A does not include a river crossing.
    - Visual impact—will likely rank second to river crossings in regard to approval timing. This is generally the issue that generates the most public opposition.

- Of the Selected Ten projects, the ones with a northern (Red Lion) crossing have 17 miles of overhead transmission. These will likely face more opposition.
- The two submarine-crossing projects have only three miles of overhead transmission.
- Project 1A has no overhead transmission.

- Transmission right of way—can generate public opposition where it passes near residences or sensitive buildings and may encounter approvals where environmentally sensitive areas are crossed.
  - The northern-crossing (Red Lion) projects will cross wetlands that could cause some delays or difficulties in getting right of way approved. This may be reduced because there is already a 500 kV line along the most-likely route.
  - The southern-crossing projects will require about three miles of right of way in Delaware.
  - None of the proposed projects seem to approach residential areas.
  - Project 1A does not require any new transmission-line right of way.
- Agency approvals required—the number of approvals and agencies required for a project will affect the risk of delays, costs, and technical requirements. In general, the more approvals required, the more risk.
  - All the Selected Ten projects will require dealing with multiple agencies. They all cross the river and involve at least some overhead transmission. Eight of them also all require significant substation work at Salem with the other two at Hope Creek. These will involve the most agency reviews.
  - Project 1A requires minimal land use and has minimal impact on substation reconfigurations. Of all the proposed projects, this has by far the least impact on existing physical facilities and the least environmental impact. All of which will limit the number of agencies involved and the required approvals.

In general, the technical risks for all the projects are smaller than the licensing and approval risks. All the projects use conventional equipment and meet the planning criteria set forth by PJM—they will all work acceptably. Eight of the Selected Ten projects have some increased risk associated with reconfiguring the Salem substation.

The bigger risks are in getting approval and the various opportunities for delays and modification as part of the licensing and approval processes. Project 1A has the least environmental impact, will be the easiest to get approved, and will be the fastest to construct and put in operation.

Finally, Project 1A is, by far, the least costly.