The New York Independent System Operator Subsynchronous Resonance Mitigation Cost Estimation

FINAL

Report No. E23496-01

23 October 2018
Revised: 31 October 2018

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Prepared for:	The New York Independent System Operator
Report No.:	E23496-01
Date:	23 October 2018
Revised:	31 October 2018

Author(s):	John P. Daniel
Reviewed by:	Vythahavya Vadlamani
Approved by:	Willie Wong

ABB Inc.
Power Grid Division
Power Consulting
901 Main Campus Drive, Suite 300
Raleigh, NC 27606

Rev No.	*Revision Date*	*Revision Description*	*Authored by*	*Reviewed by*	*Approved by*
0	10/23/18	Issued for Review	J. Daniel	V. Vadlamani	W. Wong
1	10/31/18	Addressed NYISO comments. Finalized.	J. Daniel	V. Vadlamani	W. Wong

SUMMARY

The NYES-Segment B – Public Policy AC Transmission Project (Queue #543) with the New York Independent System Operator (NYISO) area includes a series capacitor to provide 50% compensation on the new Pleasant Valley–Knickerbocker 345 kV transmission line. The series capacitor along with its bypass and protective functions will be located at the new Knickerbocker 345 kV switching station.

An earlier study to evaluate the potential for subsynchronous resonance (SSR) issues between the series capacitor and local generation was performed by another consultant on behalf of National Grid. The study indicated concerns related to the Empire, Athens and Cricket Valley generating facilities. NYISO retained ABB Power Consulting in Raleigh, NC to develop conceptual mitigation measures for the SSR issues with these generating facilities and to provide high-level cost estimates for the implementation of the measures. This report documents a review of those mitigation measures and provides high-level cost estimates for each of those that ABB supplies.

ABB has some concerns relative to the earlier study that are also documented in this report. The earlier study considered three types of subsynchronous phenomena – induction generator effect (IGE), torsional interaction (TI), and torque amplification (TA). The methods used for IGE and TA screening appear to be appropriate but some details related to the methods are unclear. On the other hand, the approach to TI is considered by ABB to be inadequate for determining whether or not TI is an actual concern for the subject plants. Preliminary, cursory evaluations by ABB indicates that TI may be a concern for the Empire plant under as little as one outage (i.e. N-1 conditions). On the other hand, studies may indicate that TI is not a concern due to the characteristics of the generators involved. In other words, based on the current information available, the risk for SSR is inconclusive and additional information about the generators is required to establish the risk for SSR. (For additional information please see Section 2.2.2 herein). *Therefore, ABB recommends that a more appropriate screening study be performed before any mitigation option is selected, to ensure that the risk for SSR has been correctly identified.*

Relative to the mitigation options, the following summaries are provided along with a recap in Table S-1. Equipment costs are the estimated installed costs. If SSR mitigation is required only at the Empire plant, ABB estimates that the costs will range between $565,000 and $1,300,000. If SSR mitigation is required at Empire, Athens and Cricket Valley the estimated costs range between $1,860,000 and $4,875,000.

From a technical perspective, ABB recommends that Option 5 be first considered followed by Option 2, then Option 4. Backup protection from a scheme similar to Option 1 is recommended for each of these recommended options.

- **Option 1: SSR Protective Relays at Generators to Trip Generators** – This option provides redundant relaying at the generator terminals to detect SSR conditions and trip the generators if necessary.

  Budgetary Costs:
  Empire facilities only:
    - Study to define generator characteristics and relay settings: $70k-$100k
    - Redundant relays and panels for 3 generators: $535k - $800k

  Empire/Athens/Cricket Valley facilities:
    - Study to define generator characteristics and relay settings: $125k-$175k
    - Redundant relays and panels for 15 generators: $2.3M - $3.5M

  Note: ABB ranks Option 1 as the 4th best in terms of technical merit. ABB's standard practice is to recommend this type of protection as back-up protection in case other mitigation measures fail. When used as back-up protection, as noted in other options below, a single relay (as opposed to redundant relays) may suffice.

- **Option 2: SSR Detection at Generators to Bypass Series Capacitor** – This option provides redundant relaying at the affected plants. It is assumed that relays monitoring the high-voltage side of the GSUs is adequate for this option. If SSR is detected at the plant, a transfer-trip signal will be sent to the Series Capacitor to bypass.

  Budgetary Costs:
  Empire facilities only:
    - Study to define generator characteristics and relay settings: $70k-$100k
    - Redundant relays and panels for 3 generators: $480k - $720k
    - Back-up generator relays and panels for 3 generators: $325k - $480k

  Empire/Athens/Cricket Valley facilities:
    - Study to define generator characteristics and relay settings: $125k-$175k
    - Redundant relays and panels for 3 generators: $1.5M - $2.3M
    - Back-up generator relays and panels for 15 generators: $1.6M - $2.4M

  Note: ABB ranks Option 2 as 2nd best in technical merit. If selected, it should be used with back-up protection at the affected generators. Note that the actual need for mitigation needs to be determined based on adequate studies of the SSR risk. If this options is selected, it should be used with non-redundant back-up protection at the affected generators.

- **Option 3: Resonant Blocking Filters** – This option places specially designed filters at the neutral end of the GSU high-voltage winding to prevent the flow of currents at specific frequencies into the system. This option has been used as some facilities in the past but has not become a "standard" solution.

Budgetary Cost: Not Available – ABB does not provide this solution

Note: ABB ranks Option 2 last in technical merit. ABB does not recommend this mitigation method.

- **Option 4: Remedial Action Scheme No. 1** – This option provides a bypass signal to the series capacitor any time a proper combination of line outages will result in SSR. As originally indicated by NYISO, the intent was to bypass the SC when all lines identified in the earlier study are out, but the issue is more complicated than implied in that study and significant communications and logic may be involved once the actual SSR risk conditions are correctly identified. A similar approach used elsewhere in the NYISO system suffered from communication issues causing nuisance bypassing of the series capacitors resulting in a blended solution using Option 4 and Option 5.

Budgetary Costs:

Empire facilities only:

Study to define generator characteristics and relay settings:	$30k-$50k
Redundant relays and panels for 3 buses:	$515k - $770k
Back-up generator relays and panels for 3 generators:	$325k - $480k

Empire/Athens/Cricket Valley facilities:

Study to define generator characteristics and relay settings:	$50k-$75k
Redundant relays and panels for 6 buses:	$620k - $930k
Back-up generator relays and panels for 15 generators:	$1.6M - $2.4M

- **Option 4a: Remedial Action Scheme No. 2** – This option provides a bypass signal to the series capacitor when only local critical transmission paths at the Knickerbocker substation that could lead to SSR become out of service. This option faces the same challenges indicated above for Option 4 – namely, that the outages that can lead to actual SSR conditions of concern need to be determined by study and it may be that some of those conditions may not involve an outage at the Knickerbocker substation.

Budgetary Costs:

Empire facilities only:

Study to define generator characteristics and relay settings:	$30k-$50k
Redundant relays and panels for 3 lines:	$210k - $315k
Back-up generator relays and panels for 3 generators:	$325k - $480k

Empire/Athens/Cricket Valley facilities:

Study to define generator characteristics and relay settings:	$50k-$75k
Redundant relays and panels for 8 lines:	$210k - $315k
Back-up generator relays and panels for 15 generators:	$1.6M - $2.4M

Note: ABB ranks Option 4/4a as 3rd best in technical merit. Note that the actual need for mitigation needs to be determined based on adequate studies of the SSR risk. If this options is selected, it should be used with non-redundant back-up protection at the affected generators.

- **Option 5: SSR Detection at Series Capacitor to Bypass Series Capacitor** – This option detects SSR at the series capacitor and bypasses the series capacitor when specified frequencies are detected at sufficient levels to be of concern.

Budgetary Costs:

<u>Empire facilities only</u>:

Study to define generator characteristics and relay settings:	$100k-$150k
Redundant relays and panels for 1 bus:	$400k - $600k
Back-up generator relays and panels for 3 generators:	$325k - $480k

<u>Empire/Athens/Cricket Valley facilities</u>:

Study to define generator characteristics and relay settings:	$125k-$175k
Redundant relays and panels for 1 bus:	$400k - $600k
Back-up generator relays and panels for 15 generators:	$1.6M - $2.4M

Note: ABB ranks Option 5 as 1st best in technical merit. The actual need for mitigation should be determined based on adequate studies of the SSR risk. If this options is selected, it should be used with non-redundant back-up protection at the affected generators.

The options above have been evaluated with the assumption that no changes can be made to the Queue #543 series capacitor itself. Additional mitigation options that might be considered for any future installations are also provided in the report for informational purposes only.

Table S-1: Mitigation options recap

Option	Description	Plants	Budgetary Costs (Installed)	Recommended Order of Technical Preference
1	Redundant SSR protection at generators	Empire	Studies: $70k - $100k Equipment: $535k - $800k *Total: $605k - $900k*	4
		Empire/Athens/ Cricket Valley	Studies: $125k - $175k Equipment: $2.3M - $3.5M *Total: $2.425M - $3.675M*	
2	Redundant SSR detection at generator plant with transfer bypass of series capacitor and backup protection at generators	Empire	Studies: $70k - $100k Equipment: $480k - $720k Backup: $325k - $480k *Total: $875k - $1.300M*	2
		Empire/Athens/ Cricket Valley	Studies: $125k - $175k Equipment: $1.5M - $2.3M Backup: $1.6M - $2.4M *Total: $3.225M - $4.875M*	
3	Resonant blocking filters on GSUs with backup protection at generators		ABB does not supply this solution and cannot comment on the potential cost.	Not Recommended
4	Remedial action scheme to identify contingencies leading to SSR risk with transfer bypass of series capacitor and backup protection at generators	Empire	Studies: $30k - $50k Equipment: $515k - $770k Backup: $325k - $480k *Total: $870k - $1.300M*	3
		Empire/Athens/ Cricket Valley	Studies: $50k - $75k Equipment: $620k – $930k Backup: $1.6M - $2.4M *Total: $2.270M - $3.405M*	
4a	Remedial action scheme to detect loss of critical lines at series capacitor bus and bypass series capacitor with backup protection at generators	Empire	Studies: $30k - $50k Equipment: $210k - $315k Backup: $325k - $480k *Total: $565k - $845k*	
		Empire/Athens/ Cricket Valley	Studies: $50k - $75k Equipment: $210k - $315k Backup: $1.6M - $2.4M *Total: $1.860M - $2.790M*	
5	Redundant SSR detection at series capacitor to bypass series capacitor with backup protection at generators	Empire	Studies: $100k - $150k Equipment: $400k - $600k Backup: $325k - $480k *Total: $825k - $1.230M*	1
		Empire/Athens/ Cricket Valley	Studies: $125k - $175k Equipment: $400k - $600k Backup: $1.6M - $2.4M *Total: $2.125M - $3.175M*	

* - represents high-end estimate only

Contents

1 Introduction

The NYES-Segment B – Public Policy AC Transmission Project (Queue #543) with the New York Independent System Operator (NYISO) area includes a series capacitor to provide 50% compensation on the new Pleasant Valley–Knickerbocker 345 kV transmission line. The series capacitor along with its bypass and protective functions will be located at the new Knickerbocker 345 kV switching station.

A previous study ([1]) performed on behalf of National Grid indicated the potential for subsynchronous resonance (SSR) issues between the series capacitor and local generation at the Empire, Athens and Cricket Valley generating facilities. NYISO retained ABB Power Consulting in Raleigh, NC to develop conceptual mitigation measures for the SSR issues with these generating facilities and to provide high-level cost estimates for the implementation of the measures.

This report documents the conceptual approaches specifically identified by NYISO along with a few other measures for consideration in future projects.

Section 2 of this report provides a few observations by ABB on the methods and results of the previous study. Section 3 describes the generating facilities being considered and the outages required to place these facilities in a radial connection to the Queue #543 series capacitor. Section 4 discusses the requested mitigation concepts, while Section 5 discusses the additional measure that could be considered. Estimated costs are only provided on the concepts of Section 4 for which ABB provides equipment.

2 Comments on Subsynchronous Phenomena

Since series compensation in transmission lines is always less than 100%, and typically less than 70%, the resonant frequency of the series connection of the transmission line and the series capacitor will be below the nominal operating frequency of the system – in other words, it will be subsynchronous. There are three primary phenomena that can occur between generation facilities and the series compensated system due to this subsynchronous resonance:

1) Induction Generator Effect (IGE) and the strongly related Subsynchronous Control Interaction (SSCI) with Type 3 wind turbine generators;
2) Torsional Interaction (TI); and,
3) Torque Amplification (TA).

The SSR screening report ([1]) provided as input for this cost estimation evaluation discusses these three phenomena, but appears to be very limited in the evaluation of the phenomena and the potential risks for the Empire, Athens and Cricket Valley generating facilities that are of concern for the effort of this report. As such, a few observations are made relative to the phenomena based on ABB's experience with subsynchronous phenomena.

2.1 Induction Generator Effect

IGE is a purely electrical phenomenon that can occur when a resonant condition (X=0) exists in the connected system impedance as viewed from the rotor of a machine looking into the system. If the resistance as viewed from the rotor is negative at the resonant frequency, an undamped situation arises and electrical oscillations at the resonant frequency will grow exponentially. While the phenomenon tends to occur more readily with asynchronous machines, the fact that it occurs at subsynchronous frequencies where synchronous machines behave as asynchronous relative to any excitation at those frequencies, IGE remains a possibility for synchronous machines as well.

Nevertheless, IGE has been something of a "red herring" when it comes to synchronous generators with few if any events actually being confirmed. The negative resistance occurs because of machine action and the slip across the air-gap making the rotor resistance appear negative when the operating speed is above that which would be associated with excitation at the resonant frequency. For the total "machine+system" resistance to appear negative, the machines typically require a relative large rotor winding resistance. Synchronous generator rotor resistances are normally too small to overcome the system losses and the addition of amortisseur windings are typically sufficient to address IGE concerns if they exist.

IGE can happen more readily with Type 1 and Type 2 wind turbine generators where high rotor resistances are used to increase the operating speed range of the asynchronous machines. A strongly related phenomenon occurs with Type 3 wind turbine generators where the controls of the parallel converter create a virtual rotor resistance that is high at subsynchronous frequencies. This phenomenon has been dubbed by the industry as

Subsynchronous Control Interaction (SSCI) and many wind turbine manufacturers have developed controls for their Type 3 machines that effectively address SSCI when needed.

The screening study of [1] addresses IGE for the generating plants evaluated, and the approach appears to be correct, but details of the generator representations are not provided, so the conclusions cannot be fully commented upon. Also, the study does not address SSCI. This is perhaps because no wind park projects in the NYISO Queue are close to the Queue #543 series capacitor. However, *ABB strongly recommends that NYISO keep in mind the possibility of SSCI if future projects desire to interconnect close to any series compensation within their system*. It is noted, as an aside, that the only events to date in which SSCI is confirmed, have occurred when the wind plant become completely radially connected to the series compensation so that there are no other alternate transmission paths or other generation between the wind plant and the series compensated lines.

2.2 Torsional Interaction

2.2.1 Concern Regarding Previous Study Results

It is ABB's opinion that the process described in [1] is inadequate for the evaluation of TI. Torsional interaction is an electro-mechanical phenomenon that requires the consideration of damping provided by the electrical system (i.e. electrical damping) on the machine shaft torsional modes as well as the inherent mechanical damping present at those modes. In order to evaluate TI, at a minimum, the electrical damping across the subsynchronous frequency range must be calculated taking into consideration of the machine's electrical characteristics and all reasonable system configurations. Then, using that electrical damping, the following general assessment can be made:

1) If the electrical damping is positive at all frequencies at which a machine torsional mode may exist, there is no TI concern;
2) If the electrical damping becomes negative under any reasonable system configuration and at any frequency at which a machine torsional mode may exist, there may be a TI concern. Without details of the machine's mechanical shaft parameters, the result is inconclusive. Knowledge about the machine's natural mechanical frequencies of rotational oscillations is required to fully access the TI risk. *Note that a reactance of zero (X=0) in the frequency scan is neither a sufficient nor a necessary condition for TI to be of concern.* This means that TI may occur at N-1 conditions even if N-3 or higher is necessary to provide a resonance (X=0) at some frequency. In addition, the frequency range of the negative electrical damping typically shifts with different contingencies and may create or remove TI concerns as it shifts.

Because [1] appears to consider TI a concern only if a zero crossing of the reactance occurs, and does so for many generators in the proximity of the Queue #543 series capacitor, *ABB strongly recommends that a study be performed that properly considers the electrical damping – and, if possible, the mechanical torsional modes – of the synchronous machines*.

2.2.2 Additional Information on TI

The discussion in this section is intended to elaborate on issues related to TI and to provide supporting information to the recommendation for the performance of an appropriate study.

Torsional interaction occurs when the effects of an electrical resonance properly align in frequency with a mechanical torsional mode of a machine. The torsional modes of interest are the subsynchronous natural modes of mechanical oscillations. These oscillatory modes are a function of the rotational inertias of the masses along a machine shaft and of the rotational stiffness of the shaft (its resistance to twisting motion as opposed to its resistance to lateral deflection).

In order to adequately evaluate TI, even in a screening study, it is necessary to identify both the mechanical resonant frequencies and the electrical damping expected to be presented by the electrical network at the generator. Ideally, this electrical damping can be directly compared to the mechanical torsional modes and their mechanical damping levels to ascertain whether or not any negative electrical damping is sufficient to overcome the inherently positive mechanical damping at the natural frequencies of the shaft. In the early stages of any generation project, it is usually difficult to obtain sufficient information about the generators to determine the mechanical modes and their damping. In such cases, some preliminary conclusions can be drawn based purely on the electrical damping and a very conservative assumption of zero mechanical damping. Doing so allows an estimation of the number of outages and the specific outages that are likely to raise a risk of SSR for a given generating facility.

An example is provided in Figure 2-1 for a sample generator that becomes radial to a series capacitor under N-3 conditions. The corresponding impedance scans are provided in Figure 2-2[1]. Note that in Figure 2-2 for N-1 and N-2 conditions, no resonance (X=0) occurs but there is a reactance dip created by the resonant, series-compensated path being in parallel to other network impedances (alternate transmission paths). Those reactance dips also correspond to increases in the resistance of the scan, which is directly related to a decrease in the electrical damping at the 60 Hz complementary frequency (i.e. $60 - f_{scan}$) in Figure 2-1.

The important point to notice about the plots in Figure 2-1 is that the risk for TI is not limited to a radial connection between the machine and the series capacitor, but can occur anytime that the electrical damping becomes negative so long as 1) the mechanical mode aligns with the negative electrical damping; and 2) the electrical damping is sufficiently negative to overcome the mechanical damping. To illustrate, two example torsional modes are provided in Figure 2-1 represented by the vertical red, dashed lines, the first is at 21.3 Hz and the second is at 29.7 Hz. The mechanical damping is defined on these lines by the top circle which indicates how low the electrical damping curve must go at the respective frequencies in order to cause a TI condition (i.e. SSR). In all cases, N-0 through N-3, the 21.3

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[1] Strictly speaking the impedance scans are performed up to 120 Hz so that the electrical damping can properly account for both the subsynchronous and super-synchronous complementary frequencies.

Hz mode is not at risk for SSR. The electrical damping will never overcome the mechanical damping. For the 29.7 Hz mode, however, SSR is likely for N-1 conditions with line 1 out and for N-2 conditions with lines 1 and 3 out, but *not* for radial N-3 conditions.

Considering the various N-2 combinations, note that the minimum of the electrical damping dip shifts frequencies depending of the specific lines that are out. This results in the conclusion that for the 29.7 Hz mode, the only N-2 condition resulting is TI is the simultaneous outage of lines 1 and 3, but there is no TI for the other two N-2 contingencies because *at the mode frequency* the electrical damping is not sufficiently negative. This is true even though the contingency with lines 1 and 2 out has a much deeper negative electrical damping. Care must be taken when considering such conclusions, however, because the mechanical damping is strongly dependent upon the loading of the generator since much of the damping derives from fluid flow (gas or steam) through the turbines. More heavily loaded machines have better mechanical damping requiring even more negative electrical damping to result in SSR conditions.

A nuance to these plots is that the N-0 shows negative damping above about 30Hz, but this is characteristic of the generator parameters and no TI is expected under these conditions or the machine would never operate stably even on an intact system.

Another nuance that must be considered for the plants under evaluation here is the influence of neighboring machines. If the other machines in the plant are identical, they will act in sympathy with one another increasing the potential risk for SSR for all of the on-line machines. This is because they share common torsional mode frequencies and act in concert to any disturbance to the system. A similar effect may occur if non-identical machines within the plant or nearby on the system share a common torsional mode frequency. On the other hand, if there are machines at the same plant or nearby on the system that have distinctly different torsional mode frequencies, they provide a more or less mitigating influence on the machines that do not share their torsional mode frequencies. This must be taken into account when considering combined cycle units because the gas turbines (GTs) typically have different modes than the steam turbines (STs). The operation of the GTs in simple cycle mode must be considered as well as the combined cycle modes with both GTs and steam turbines on-line.

While all machines can differ, it has been ABB's experience that GTs typically have one (1) subsynchronous torsional mode that is usually in the range of 20 to 22 Hz (rotor frame), while the accompanying STs usually have two or three subsynchronous modes with only one of them having sufficiently low mechanical damping to present significant concern for SSR. These modes range from 21 Hz to 50 Hz (rotor frame). The torsional modes of the STs and the GTs need only differ by about 0.5 Hz or less to begin providing a mitigating influence to each other, although in some cases torsional modes that are separated by less than 2 Hz may result in a "beat" in the torques on the machines.

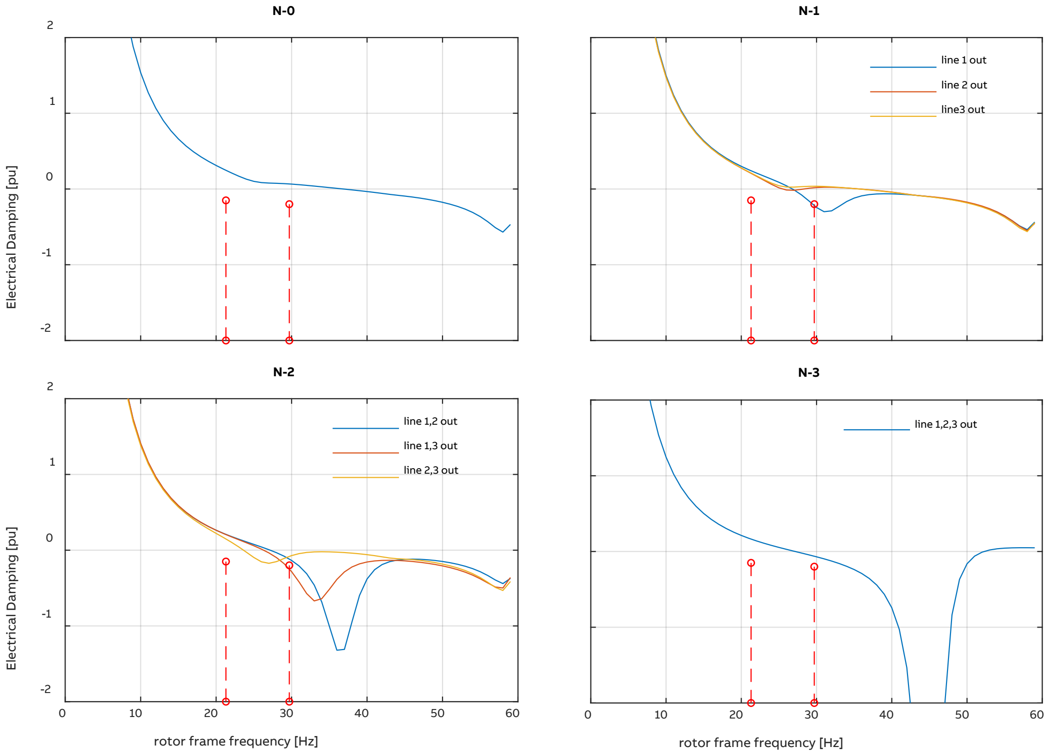

Figure 2-1: Electrical damping curves for example generator that becomes radial to series compensation under N-3 conditions

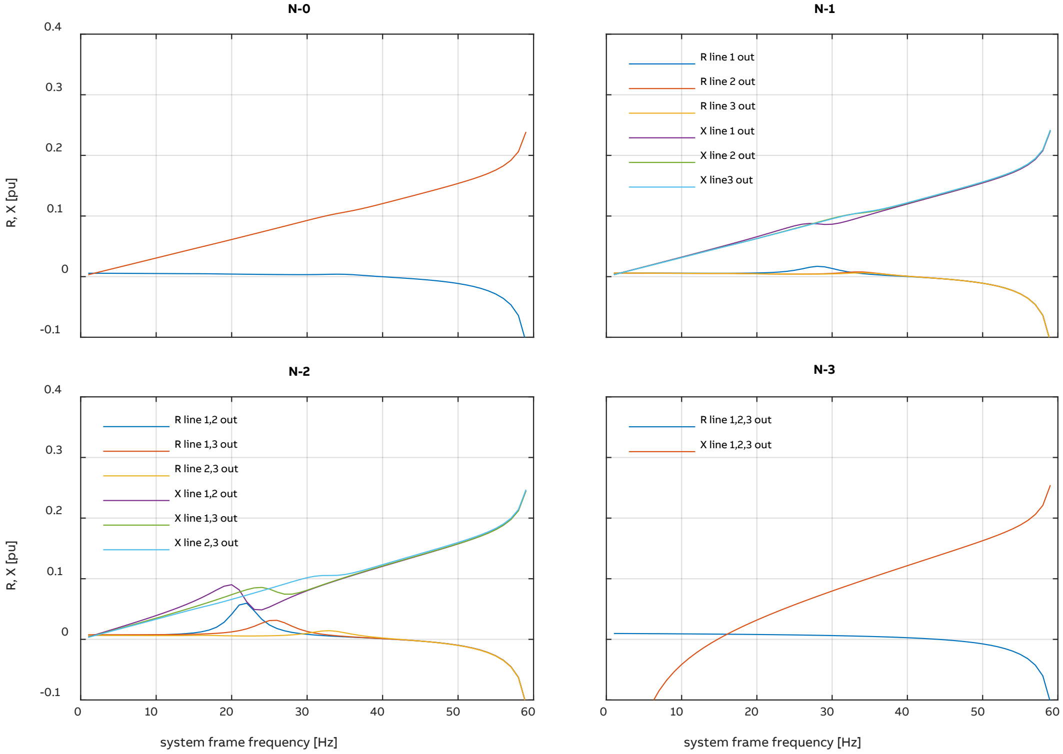

Figure 2-2: Impedance scans for example generator that becomes radial to series compensation under N-3 conditions

2.3 Torque Amplification

While the method used in [1] for screening for torque amplification is a typical method within the industry, it is, in ABB's experience, highly conservative. That is, it often indicates potential TA concerns under conditions for which actual TA is unlikely to occur. In addition, the representation of the machine impedance in the effort is not clear, so the conclusions cannot be fully commented upon.

Torque Amplification is a phenomenon that is strongly related to the resonant conditions observed from the machine immediately prior to application of, or immediately following the clearing of a fault. It is typically quite sensitive to fault location as well. If there is any concern about TA for a given plant, *ABB strongly recommends a detailed study (in an electromagnetic transients program such as PSCAD) that considers such issues along with the model of the machine shaft*.

If TA is observed, very careful evaluation of the transient simulations in comparison to a Stress-Number (S-N) curve should be considered to estimate shaft loss-of-life. This assumes that an S-N curve can be obtained from the machine manufacturer.

3 Generating Facility Descriptions

NYISO requested SSR mitigation cost estimates for two sets of generating facilities:

1. Empire
2. Empire, Athens and Cricket Valley

The plant descriptions and their association with the Queue #543 series capacitor are provided below.

3.1 Empire

The Empire plant is the same as identified in [1] as Besicorp. The plant is comprised of three generators, two of which are rated at 223 MVA and one which is rated at 358 MVA. As shown in Figure 3-1, the plant is electrically close to the Queue #543 series capacitor and can achieve a fully radial connection with the simultaneous loss of three (3) elements:

1. Alps – Berkshire 345 kV line
2. New Scotland – Knickerbocker 345 kV line
3. Reynolds Road 345/115 kV transformer

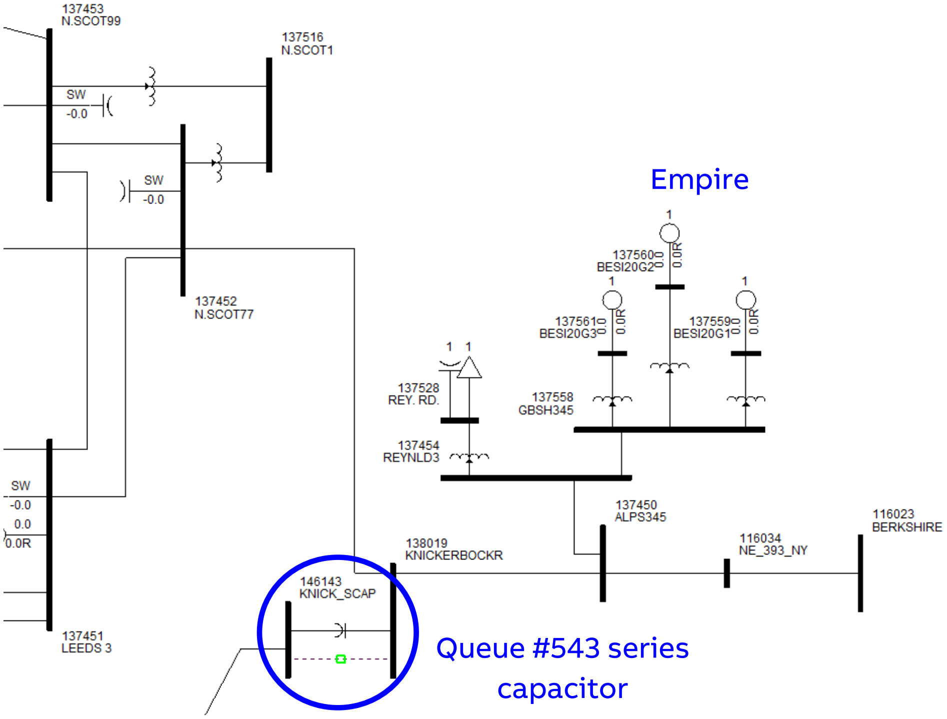

Figure 3-1: New York transmission system in the vicinity of the Empire generation facility and Queue #543 series capacitor.

A cursory review of the system suggests that the Reynolds Road transformer will have little impact on potential for TI on these machines. On the other hand, the system beyond New Scotland has a stronger short-circuit capacity than the Massachusetts system connected beyond Berkshire, suggesting that it will have the greatest influence on TI. Nevertheless, it is probable that the loss of either of these 345kV lines has the potential of exposing the plant to TI risk. In other words, there is a strong likelihood that the plant may be exposed to TI under N-1 or N-2 conditions and a more rigorous evaluation is recommended to help establish the operational mitigation measures that are most critical.

When doing so, as much detail about the plant as available should be considered. The plant configuration strongly suggests a combined cycle plant with two gas turbines (GTs) and one steam turbine (ST). As such it is likely, but not certain, that the GTs will provide some amount of mitigation to the ST and the ST will provide some amount of mitigation to the GTs assuming the different turbine types do not share a common torsional mode frequency. If this is the case, the most sensitive condition will be when the two GTs are on-line together and operating in the simple cycle mode.

3.2 Athens and Cricket Valley

The Athens and Cricket Valley generating facilities connect to the Queue #543 series capacitor via the Pleasant Valley 345 kV bus, as illustrated in Figure 3-2.

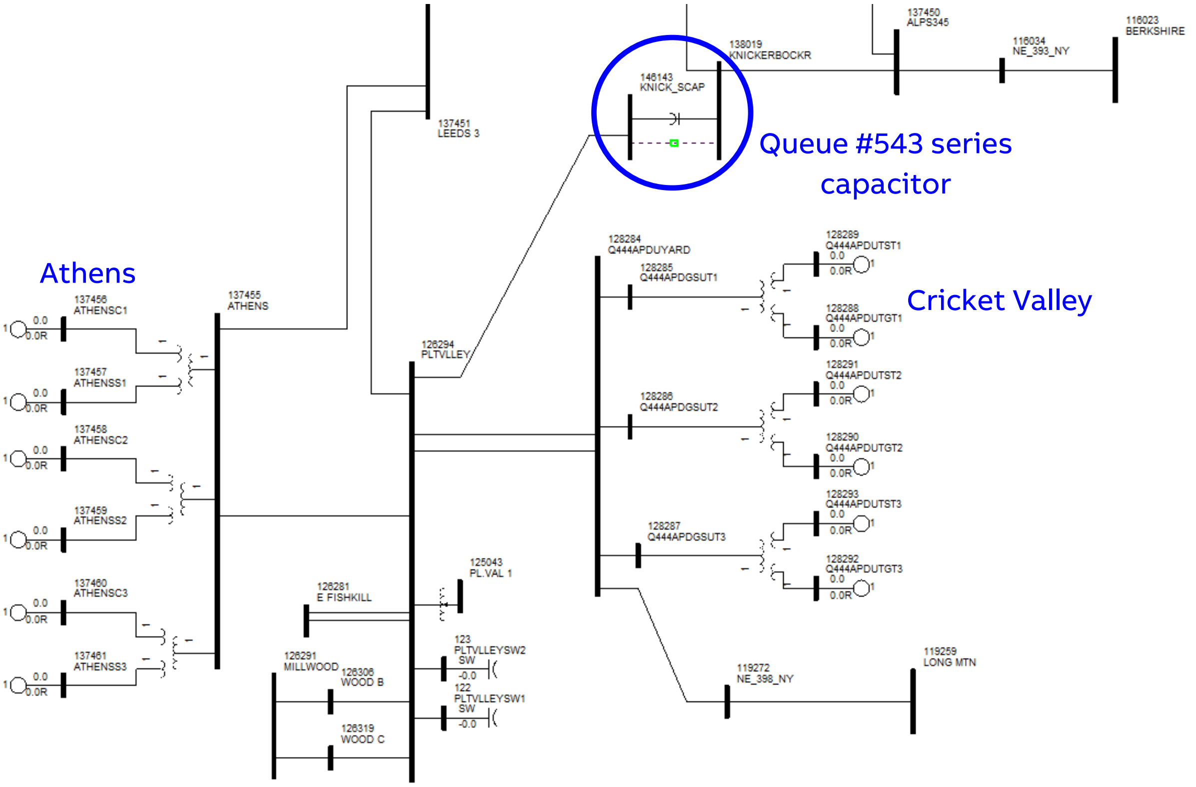

Figure 3-2: New York transmission system in the vicinity of the Athens and Cricket Valley generation facilities and the Queue #543 series capacitor.

Both facilities are combined cycle plants, with three GT/ST pairs each. Based on the PSS/E data, each pair is on a three-winding GSU. At Athens the GTs are 318 MVA and the STs are 161 MVA. At Cricket Valley the GTs are 278 MVA and the STs are 205 MVA.

The outages needed to create a radial connection to the series capacitor will depend on how the plants are being, or need to be, treated. If both Athens and Cricket Valley have generators with identical torsional modes (which is highly unlikely given the differences in machine ratings) then they can properly be treated as sister plants that are expected to sympathize with each other. In that case, the following outages are necessary to place both plants radial to the series capacitor:

1. Pleasant Valley 345/115 kV transformer
2. Pleasant Valley – Wood B 345 kV line
3. Pleasant Valley – Wood C 345 kV line
4. Pleasant Valley – East Fishkill 345 kV circuit 1
5. Pleasant Valley – East Fishkill 345 kV circuit 2
6. Pleasant Valley – Leeds 345 kV line
7. Cricket Valley – Long Mountain 345 kV line
8. Athens – Leeds 345 kV line

These outage together would result in an N-8 contingency, which is an extremely rare occurrence which would probably prevent the plants from continuing to operate at full capacity. Even so, as has been discussed extensively before, TI may occur under contingencies far less severe than this. If all of the GTs are on line in simple cycle mode, then based on experience it might reasonably be expected that TI would be a concern under N-3 or higher conditions.

However, because of the differences in the machine ratings and the likely differences in torsional mode frequencies, the more reasonable approach would probably be to evaluate the plants separately. In this case the outages to make the Athens plant radial to the series capacitor would be:

1. Pleasant Valley 345/115 kV transformer
2. Pleasant Valley – Wood B 345 kV line
3. Pleasant Valley – Wood C 345 kV line
4. Pleasant Valley – East Fishkill 345 kV circuit 1
5. Pleasant Valley – East Fishkill 345 kV circuit 2
6. Pleasant Valley – Leeds 345 kV line
7. Pleasant Valley – Cricket Valley 345 kV circuit 1
8. Pleasant Valley – Cricket Valley 345 kV circuit 2
9. Athens – Leeds 345 kV line

And, the outages to make the Cricket Valley plant radial to the series capacitor would be:

1. Pleasant Valley 345/115 kV transformer
2. Pleasant Valley – Wood B 345 kV line
3. Pleasant Valley – Wood C 345 kV line
4. Pleasant Valley – East Fishkill 345 kV circuit 1
5. Pleasant Valley – East Fishkill 345 kV circuit 2
6. Pleasant Valley – Leeds 345 kV line
7. Pleasant Valley – Athens 345 kV line
8. Cricket Valley – Long Mountain 345 kV line

Without an appropriate study that account for the system electrical damping and the torsional modes of the generators involved, it is very difficult to say which of these outages is most critical, but based on the fault current contributions at the Pleasant Valley 345kV bus, it would appear that the most influential will be the connections to East Fishkill and to the other generating facilities – Cricket Valley when considering Athens and Athens when considering Cricket Valley. The loss of connections to Wood are also expected to contribute significant influence on SSR. All of this means that the potential outage configurations leading to SSR concerns may be a long and complex list.

4 Requested SSR Mitigation Options

This section specifically discusses the SSR mitigation options NYISO requested be evaluated.

4.1 Option 1 – SSR Protective Relays at Generators

4.1.1 Option 1 Description

The first SSR countermeasure option requested for evaluation is the use of "fully redundant protective relays to detect an SSR condition at the impacted generator(s) and trip the impacted generator(s)." This is illustrated for each plant in Figure 4-1.

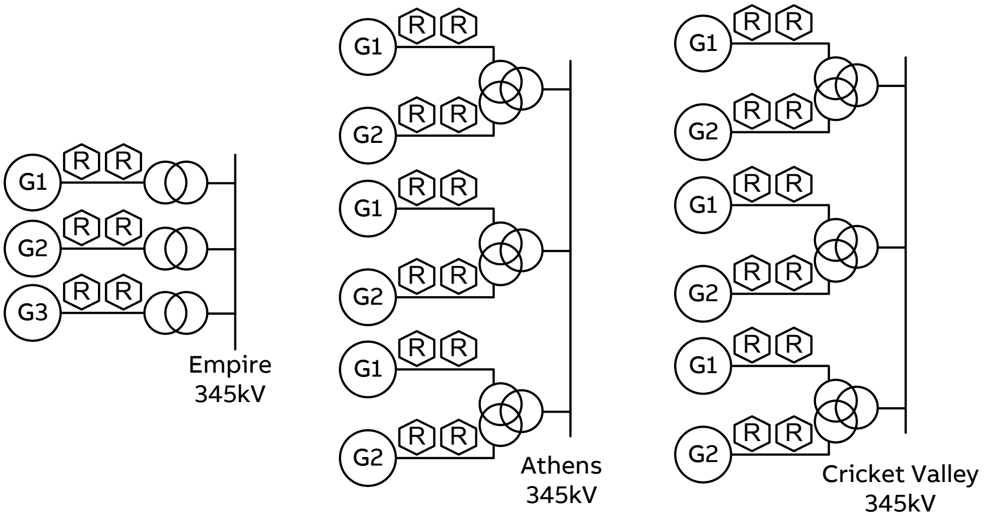

Figure 4-1: Option 1 Configuration at each generating plant.

While the few manufacturers that provide SSR relay functions may have differing approaches, ABB's approach is to detect the presence of SSR in the electrical output of the generator. The current or voltage at the terminal of the generator is measured and analyzed to determine the presence of the specific subsynchronous modal frequencies of the protected generator. If these subsynchronous quantities reach a level of concern, the generator is tripped. It has been ABB's experience that for direct generator protection it is best to monitor the terminal voltages for this protective function ([3]).

Please note that it is ABB's standard practice to recommend direct generator protection as back-up protection *for any instance in which there is a reasonable risk of SSR/TI to a generator* in the unlikely event that other mitigation measures fail. This option is not typically recommended as the primary SSR countermeasure. *As such, ABB recommends that – regardless of other mitigation options that may be selected – SSR relays be placed on all generators that are shown through adequate study to be at risk to SSR concerns and specifically to TI*. When used as back-up protection redundant relays are not considered to be necessary, since they back-up other mitigation measures that are likely to be redundant.

4.1.2 Option 1 Pros and Cons

The most obvious benefit to this option is the local and immediate protection of the generators from a phenomenon that can potentially result in catastrophic damage to the machines. This option also allows for a specific targeting of the unique characteristics of the machine being protected – that is, each relay can be tuned to the specific torsional modes that studies have determined will need to be monitored. This allows the generation to be tripped only if there is a direct risk to the machine itself. For example, in the combined cycle plants being considered, if an ST comes under an SSR condition but the companion GTs do not, it may only be necessary to trip the ST. Of course, if the situation is reversed such that the GTs are under an SSR condition but the ST is not, the ST will also need to be tripped.

The main drawback to Option 1 is that it trips the generation. If it is found that SSR is at risk under a low number of transmission outages, the generation may trip often depending on how frequently the critical line(s) trip. This may be of concern for the Empire facilities since it requires very few outages to place the facilities directly radial to the series capacitor. It is less likely to be of concern for either the Athens or the Cricket Valley plants.

It is noted that the number of relays required to protect a single generator will depend on the number of torsional mode frequencies to be monitored. If there are three or less torsional modes to be monitored on a given machine, then a single relay should be sufficient for that machine. If more torsional modes are of concern, additional relays may be needed to monitor all of the modes.

4.1.3 Option 1 Cost Estimate

The following budgetary cost estimates assume that a single relay is sufficient for each machine and redundant relays have been provided. They are approximate installed costs.

Empire Facilities

- Study to define generator characteristics and relay settings: $70k - $100k
- Redundant relays and panels for 3 generators: $534k

Empire/Athens/Cricket Valley Facilities

- Studies to define generator characteristics and relay settings: $125k - $175k
- Redundant relays and panels for 15 generators: $2.3M

4.2 Option 2 – SSR Detection at Generators, Series Capacitor Bypass

4.2.1 Option 2 Description

The second option requested for evaluation is "fully redundant protective relays to detect an SSR condition at the impacted generator(s) and to initiate a signal to bypass the series compensation." This option is illustrated in Figure 4-2.

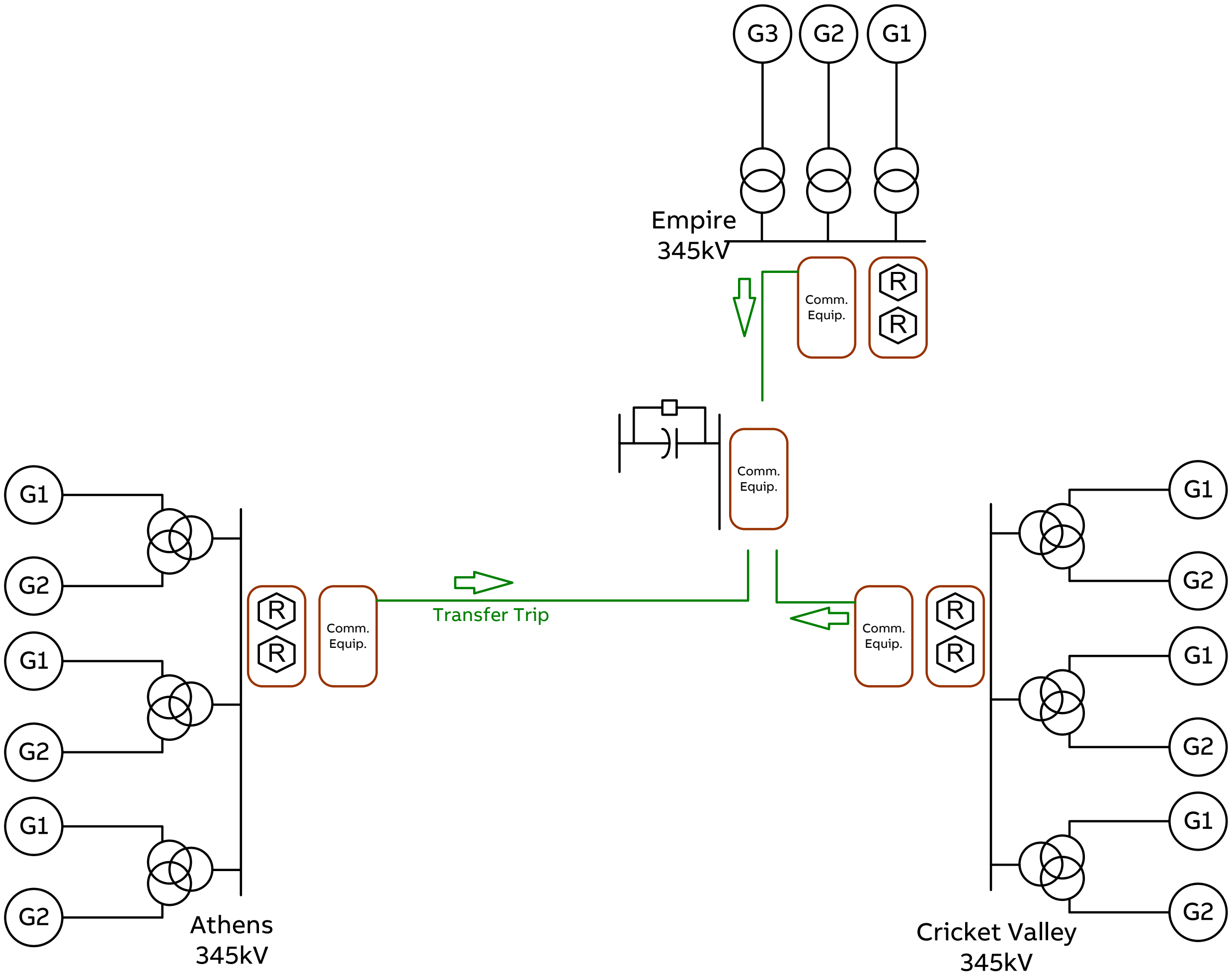

Figure 4-2: Option 2 Configuration.

This differs somewhat from Option 1 in that the focus is on detecting any SSR condition at the plant, which a single relay may be able to detect given the number of lighter damped subsynchronous modes in typical combined cycle units.

4.2.2 Option 2 Pros and Cons

The primary benefit to Option 2 is that a single set of redundant relays at each plant may be able to achieve the goals of the mitigation. In ABB's experience GTs tend to have only one subsynchronous torsional mode, while the companion STs tend to have two or three subsynchronous modes with one of those being highly damped or having a very low generator participation factor (the system cannot influence these modes significantly). At each generating plant, this means that there are likely to be only two or three modes that require monitoring. Further, more complete studies may show that only one of these modes at each plant is at risk for destabilizing SSR under any of the outage conditions.

The primary drawback to Option 2 is that it trips the series capacitor under contingency conditions in which generators are still producing. The typical purpose for a series capacitor is to improve the transfer capability of a transmission path and suddenly reducing this capability under contingency conditions (often exactly when it is desirable to have it) may lead to system stability concerns unless generation is simultaneously reduced.

A second potential drawback is the requirement for communications to initiate the transfer trip. In order to accomplish the trip, the communications must be reliable and intact, or the mitigation measure will fail.

Of the six options requested by NYISO for evaluation, ABB ranks this as the second best option for consideration.

4.2.3 Option 2 Cost Estimate

Empire Facilities

- Study to define generator characteristics and relay settings: $70k - $100k
- Redundant relays and panels for 1 bus: $480K
- Back-up generator relays and panels for 3 generators: $325K

Empire/Athens/Cricket Valley Facilities

- Studies to define generator characteristics and relay settings: $125 - $175k
- Redundant relays and panels for 3 buses generators: $1.5M
- Back-up generator relays and panels for 15 generators: $1.6M

4.3 Option 3 – Resonant Blocking Filters

4.3.1 Option 3 Description

The third option requested for evaluation is the use of a “resonant blocking filter in series with the impacted generator(s).” This option appears to be that described in [4] for the Navajo project in the mid 1970’s and in [2] (pg. 260). This mitigation measure places a separate tank filter for each mode to be mitigated at the neutral side of each phase of the GSU high-voltage winding. The neutral side of the high-voltage winding is selected because it is the point of lowest current and voltage requirements for the filter equipment. An example arrangement, which assumes two torsional modes to be mitigated, is illustrated in Figure 4-3. The components are selected such that there are low losses added at fundamental frequency, but sufficient damping is added at the torsional mode frequencies to help damp the transient torques (i.e. reduce TA).

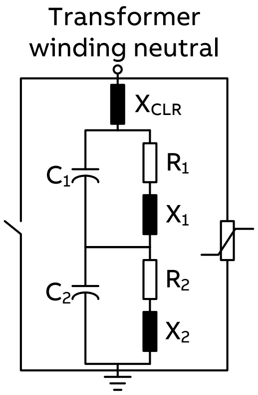

Figure 4-3: Series blocking filter for two torsional modes.

4.3.2 Option 3 Pros and Cons

Benefits to the resonant blocking filter include the fact that it passively mitigates the SSR issues. Simulations for the Navajo installation showed it to be effective in addressing both TI and TA ([4]).

On the other hand, several potential drawbacks should be considered. First, the GSU must be designed to accept the connection of the filters at the neutral end of each primary winding. If the GSUs have not yet been designed, this can be more readily addressed, but on existing plants it may mean the replacement of the GSUs. The transformer design must also include a higher BIL since the neutral voltage will be raised during any transient event that may result in the generation of the torsional mode frequencies.

In addition, consideration must be given to the detuning of the filters that occurs due to temperature variations and capacitor can losses. Further, the performance of the filters during system swings and other operation at off-nominal frequencies must be evaluated during the design stage to assess the adequacy of the filter performance.

It is noted that this solution is not, as ABB understands it, a standard solution within the industry. This may be due to several reasons including potential difficulties in assuring filter performance under the variations described above and the associated liability for poor performance.

4.3.3 Option 3 Cost Estimate

ABB does not supply this solution as an SSR mitigation measure and cannot comment on the budgetary cost.

4.4 Option 4 – Remedial Action Scheme No. 1

4.4.1 Option 4 Description

The fourth option specifically requested for consideration is a “fully redundant Remedial Action Scheme to bypass the series compensation when all combinations of critical transmission outages that lead to SSR become out of service.” The option is illustrated in Figure 4-4.

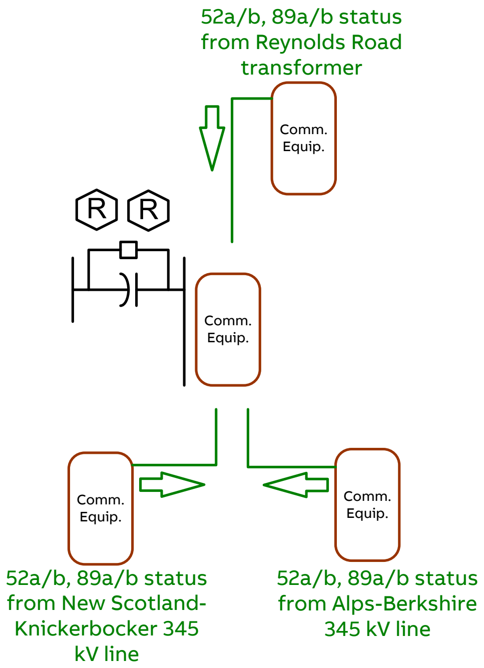

Figure 4-4: Option 4 Configuration.

This option appears to be based on [1], which concluded that the only SSR issues associated with the interconnection of the Queue #543 project occurred under the N-3 contingency of the following elements:

1. Alps – Berkshire 345 kV line
2. New Scotland – Knickerbocker 345 kV line
3. Reynolds Road 345/115 kV transformer

ABB does not recommend this solution as stated. As indicated in Section 2.2, it is reasonably possible for Torsional Interaction between the series capacitor and the generating facilities – especially the Empire generation – to occur under N-1 or N-2 conditions, but not under N-3. It is also possible that there is ultimately no concern for TI at all. The ultimate risk and ultimate mitigation will depend on the interaction of the torques created by the electrical and mechanical systems at specific frequencies.

If Option 4 is to be considered, then it is actually more complex than stated above. The logic would have to be established so that any combination of the three elements (for Empire) *that has been shown to lead to SSR conditions* would initiate a bypass of the series capacitor. For example, a bypass may need to be initiated when element 2 from the above list is out alone, and also when elements 1 and 3 are out simultaneously, but perhaps not when elements 1 and 3 are out on their own, nor when element 2 is out simultaneously with one of the others, nor when all three elements are out together.

4.4.2 Option 4 Pros and Cons

It should be noted that this approach requires that additional communications be established between the substations involved and the series capacitor. Since the series capacitor is near/at the Knickerbocker 345 kV station it is reasonable to establish communications from the Alps and Reynold Road substations for the Empire contingencies and from the Pleasant Valley, Athens and Cricket Valley substations for the other contingencies. The increased communication requirements will add complexity to this solution.

Another drawback to this solution is the same as any option that relies on bypassing the series capacitor; namely, bypassing the series capacitor may detrimentally impact the system's stability under the contingencies involved.

It is noted that this approach has been attempted in at another installation within NY. It is ABB's understanding that communication failures resulted in numerous instances of nuisance bypassing of the series capacitors. Due to this, the approach is being changed to a blended solution involving Option 4 and Option 6.

4.4.3 Option 4 Cost Estimate

Empire Facilities

- Study to define generator characteristics and relay settings: $30k - $50k
- Redundant relays and communication panels for 3 buses: $515k
- Back-up generator relays and panels for 3 generators: $325k

Empire/Athens/Cricket Valley Facilities

- Studies to define generator characteristics and relay settings: $50 - $75k
- Redundant relays and communication panels for 6 buses: $620k
- Back-up generator relays and panels for 15 generators: $1.6M

4.5 Option 4a – Remedial Action Scheme No. 2

4.5.1 Option 4a Description

The next option requested for evaluation is a "fully redundant Remedial Action Scheme to bypass the series compensation when only local critical transmission paths at the Knickerbocker substation that could lead to SSR become out of service." The option is similar to Option 4 but the remedial action scheme is limited to only the Knickerbocker substation. It is illustrated in Figure 4-5 assuming that the communications for the breaker status at the far end of the critical transmission paths are already available.

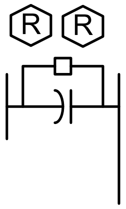

Figure 4-5: Option 5 Configuration.

4.5.2 Option 4a Pros and Cons

This option is much easier to implement than Option 4 because it relies only on communications at the local station (it is assumed that this includes information on the breaker status at the far end of the critical path). Care must be taken, however, to ensure that any conditions that involve SSR are all contingent upon the outage of the local lines connected to the Knickerbocker substation. Torsional Interaction can have complicated behavior because the outages of different lines will result in a shifting of the frequencies at which negative electrical damping from the system occur. This may mean, for instance, that the outage of the local line is actually the event that prevents TI from occurring with the local generation.

The effectiveness of this option must be determined by further study to identify the critical contingencies that may lead to SSR. If the critical contingencies do indeed always involve lines connected to the Knickerbocker substation, then this option would be effective and the ease of implementation may be desirable. The more comprehensive approach when considering remedial action schemes is that indicated as the alternate for Option 4; namely, use the complex logic necessary to detect those contingency conditions that have been demonstrated to lead to SSR concerns. This will require the additional communications and logic which Option 5 seeks to eliminate, but based on the cursory evaluations performed to date, Option 5 is not guaranteed to be sufficient to mitigate the SSR issues with the Empire generating plant.

And, of course, this option raises the concern that bypassing the series capacitor may detrimentally impact the system's stability under the contingencies involved.

4.5.3 Option 4a Cost Estimate

Empire Facilities

- Study to define relay settings: $30k - $50k
- Relay programming for 1 bus: $210k
- Back-up generator relays and panels for 3 generators: $325k

Empire/Athens/Cricket Valley Facilities

- Studies to define relay settings: $30k - $50k
- Relay programming for 1 bus: $210k
- Back-up generator relays and panels for 15 generators: $1.6M

4.6 Option 5 – SSR Detection at Series Capacitor, Series Capacitor Bypass

4.6.1 Option 5 Description

The final option specifically requested for evaluation is a “fully redundant Remedial Action Scheme to close the bypass breaker on the series compensation when SSR conditions are detected by the special SSR relays at the series compensation device.” The option is illustrated in Figure 4-6.

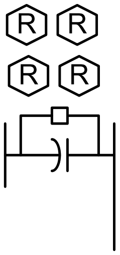

Figure 4-6: Option 6 Configuration.

This option will rely on the detection of SSR currents or voltages at the series capacitor. The SSR detection function using electrical parameters indicates that it will either be incorporated in the series capacitor control system (which often do not have the desired measurement resolution) or will be added by an appropriate relay integrated to the series capacitor facilities.

4.6.2 Option 5 Pros and Cons

The primary benefit of this option is that it allows detection of SSR conditions at the series capacitor itself, eliminating complex communications and relay logic. The solution is fairly elegant but may have some complexities for implementation. If tuned just for the Empire facilities, only the SSR frequencies expected to be produced by those generators need be monitored. This can likely be accomplished with the basic configuration of the appropriate ABB relay. If it becomes necessary to tune the protection to cover Empire, Athens and Cricket Valley (or any combination) the number of frequencies may increase to a level in which more than one relay will be required to detect all of the frequencies of concern.

Establishing the correct settings for the relays is expected to be somewhat challenging to ensure protection of all of generation facilities before damage occurs. This will require careful study. Preliminary evaluations suggest that the network conditions that create a potential SSR condition also result in a condition in which the SSR currents are approximately equal to or are amplified above those at the generator plant primary bus. This suggests that it may be as easy to detect SSR currents at the series capacitor as at the plant bus in Option 2. Complexities around this associated with protecting multiple plants need to be explored.

A complication in determining the actual pick-up settings for the relays arises from the sympathetic behavior of identical machines. Consider the situation when both Empire GTs are operating in simple cycle mode under an SSR condition. Both will respond with growing torques producing SSR currents that are likewise increasing in magnitude. The relay at the series capacitor must be set such that

- Series capacitor bypass is initiated before shaft damage is expected to occur on either GT shaft;
- False tripping does not occur when the SSR frequencies are detected due to a large disturbance that is not SSR.

The setting needed to achieve the desired results may then be too high to bypass the series capacitor when only one GT is operating and producing half the current into the series capacitor for the same torque on the individual generator. On the other hand, if the relay setting is such that the single GT is protected, then it may be too low for normal, damped disturbances such as faults near the generators. Ultimately, a careful study will be required to establish the relay settings even if mitigation is only needed for a single generating facility, such as Empire.

Like many other options, this option also raises the concern that bypassing the series capacitor may detrimentally impact the system's stability under the contingencies involved.

Of the six options requested by NYISO for evaluation, ABB ranks this as the best option for consideration.

4.6.3 Option 5 Cost Estimate

Empire Facilities

- Study to define relay settings: $100k - $150k
- Redundant relays and panels for 1 bus: $400k
- Back-up generator relays and panels for 3 generators: $325k

Empire/Athens/Cricket Valley Facilities

- Studies to define relay settings: $125k - $175k
- Redundant relays and panels for 1 bus: $400k
- Back-up generator relays and panels for 15 generators: $1.6M

5 Additional SSR Mitigation Options

There are several options that are not included in the previous discussion which may be worthy of consideration. These are discussed individually below.

5.1 Supplementary Damping Controller

With some excitation systems, a supplementary damping control signal can be added to the field voltage to apply torque to the machine in manner that yields positive damping to the torsional modes. This option is somewhat limited because the excitation system must allow for the injection of an additional signal. Further, in the systems that have utilized the excitation system for damping, the input signal has been taken from the machine torsional motion. To get this signal, additional equipment (tooth wheels or laser measurements) may need to be added to the generator.

5.2 Dynamic Stabilizer

A dynamic stabilizer is an active shunt device connected close to the generator terminals which is controlled in a manner that currents from the device add a sufficient level of electrical damping on the machine to help prevent undamped TI. Such a device has been rarely used in the past and has not been an industry standard solution with commercialized products. The devices have in the past have been very similar to SVCs, but ABB sees no reason that a STATCOM utilizing a voltage source converter would not be able to provide the same functionality and may, perhaps, provide better control for an SSR damping function.

5.3 Series Capacitor Modifications

While it may be too late to adjust the design of the Queue #543 series capacitor, for future reference, there are several options to the series capacitor design that can be considered for SSR mitigation. These include:

1) Segmented Series Capacitor
2) TCSC
3) SC Damping Filter

5.3.1 Segmented Series Capacitor

A change in the design of a series capacitor is possible such that the series compensation is provided in multiple segments with the individual bypass of each segment being possible. For example, consider the two segment configuration illustrated in Figure 5-1.

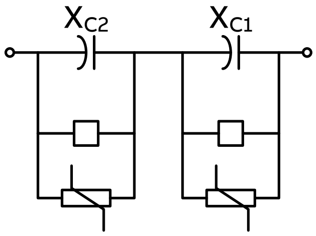

Figure 5-1: Segmented series capacitor configuration

The total compensation provided by both segments is $(X_{C1}+X_{C2})/X_{Line}$, but a reduced compensation level can be obtained through bypassing one of the segments. When this happens the frequency of the potential SSR will change – to a higher frequency as seen from the machine rotor (i.e. rotor reference frame) and to a lower frequency when viewed from the generator terminals. If the shift is to a frequency that is free from TI risk for any of the proximate generators, then the SSR is mitigated without removing the entirety of the series compensation. If bypassing the entire capacitor would result in system instabilities, bypassing only a portion of the capacitor may provide a stable system response.

The drawbacks of this arrangement are an increase in platform area, more complex controls, an increase in the equipment components required (e.g. additional breakers and MOVs), and the associated costs.

5.3.2 Thyristor Controlled Series Capacitor (TCSC)

The TCSC is a well-established device that has many installations across the world, with some installations being put in place specifically to address SSR issues that would otherwise occur with fixed series capacitors. The basic configuration of a TCSC (ignoring the protection) is shown in Figure 5-2.

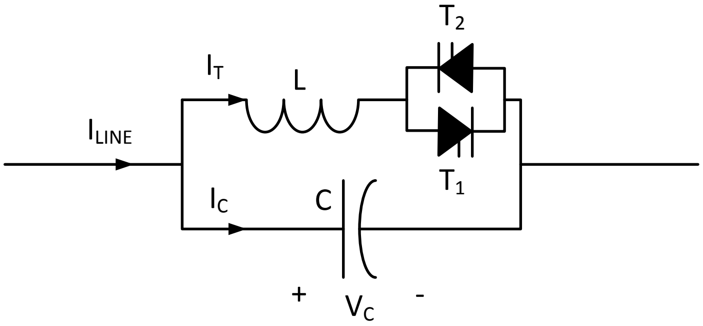

Figure 5-2: Basic TCSC Topology

The primary purpose of the TCSC is to allow for the Vernier control of the series compensation level within a limited range. The thyristor switching is controlled in a manner that boosts the voltage across the capacitor due to the transient pulse that occurs in the resonant LC circuit. Since the line current remains unchanged, the increased voltage creates an effectively larger capacitance.

When properly controlled, the TCSC has the added benefit of appearing inductive over the majority of the subsynchronous frequency range. This means that SSR cannot occur over the frequency range where the TCSC appears inductive. The effective impedance of an example TCSC is shown in Figure 5-3 for illustration[2]. In this instance, the effective impedance is inductive until approximately 48 Hz, which means that no SSR can occur with torsional modes of 12 Hz or higher. Whether or not SSR can occur with lower frequency

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[2] ABB uses a patented synchronous voltage reversal (SVR) control scheme that allows for improved SSR performance and for the characteristics shown in Figure 5-3.

torsional modes depends upon the individual machines and the interconnected system under its various possible configurations, but other issues are involved and, to date, no SSR has occurred with a properly controlled TCSC.

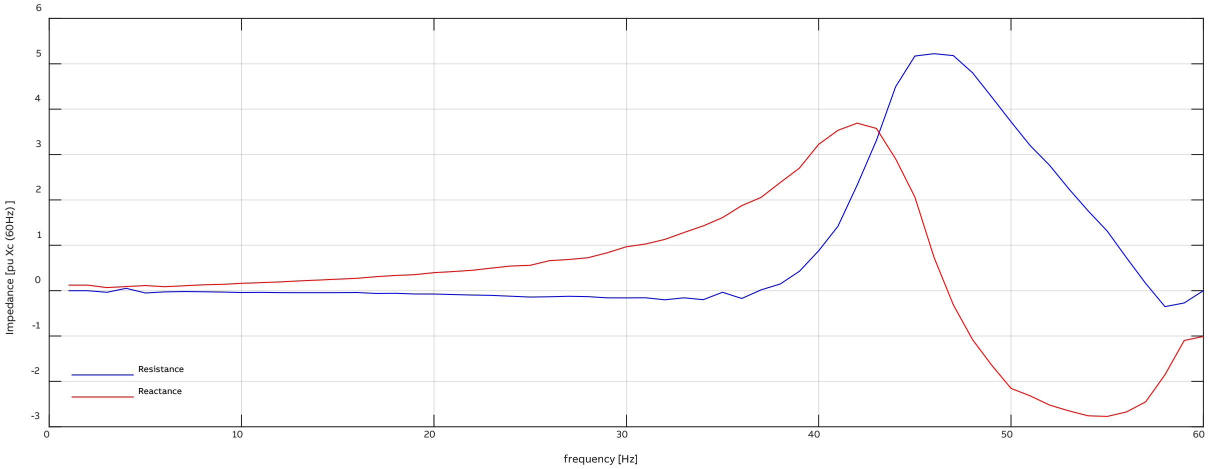

Figure 5-3: Effective TCSC impedance

The TCSC is, of course, much more complex than a passive fixed series capacitor, requires additional platform, controls and equipment, and has a higher price than a fixed series capacitor.

5.3.3 Series Capacitor Bypass Damping Filter

The philosophy behind the bypass damping filter is not unlike that leading to the use of series blocking filters at the generator GSU, but its application is at the series capacitor itself and the filter is designed to block fundamental frequency currents through the filter instead of SSR currents. A general configuration is show in Figure 5-4. The filter across series capacitor segment XC2 is tuned to block fundamental frequency currents. This allows the SSR currents to pass through the filter and allow the added filter resistance to add damping at those frequencies. A typical impedance characteristic plot is shown in Figure 5-5. As can be seen in the plot the resistance of the combined series capacitor/filter is fairly high across a broad spectrum of frequencies dropping off between 30 Hz and 40 Hz.

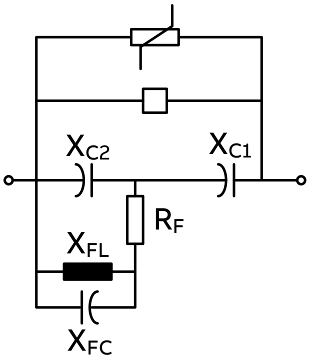

Figure 5-4: Series capacitor bypass damping filter configuration

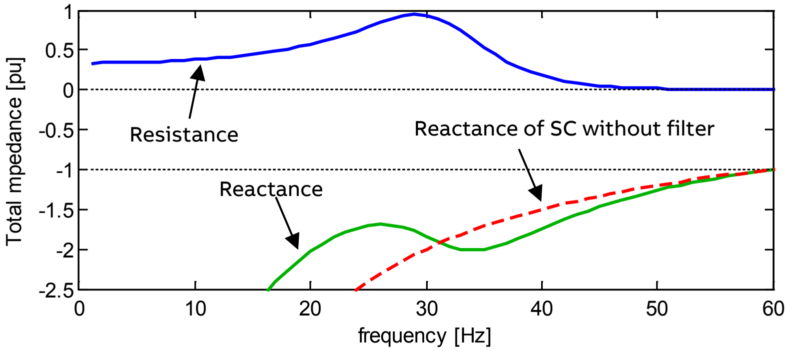

Figure 5-5: Series capacitor bypass damping filter impedance characteristics

There is limited experience with such a device and ABB is aware of only a single project in which the filters have been implemented (GE holds a patent on the concept). Nevertheless, it appears in ABB's view that it may be an effective means of SSR mitigation if the design is adjusted to appropriately address the torsional modes of the nearby machines.

The configuration in Figure 5-4 shows the filter across only a portion of the series capacitor, but it need not be limited to this, and it is possible to develop a design that will give characteristics that are quite similar to the TCSC. However, there are some design concerns that must be addressed, which are similar to those of the series blocking filters, namely that changes in capacitance due to temperature and capacitor-can failures, with the associated detuning, must be considered. System frequency deviations must be considered also. The tuning of the bypass filter would typically be done for nominal system frequency, but as the system frequency deviates from nominal the losses in the filter may become quite large. Even at nominal frequency, the filter "tank" circuit circulates fundamental frequency currents and a low quality inductor may result in very high losses.

6 References

[1] *Queue #543 Sub-Synchronous Resonance Screening Study*, Burns & McDonnel Engineering Company, Project No. 74300, Revision 1.3, 9/17/2018.

[2] *Series Compensation of Power Systems*, P.M. Anderson, R.G. Farmer, PBLSH!, Inc. Encinitas, California, 1996.

[3] "Design Challenges for Numerical SSR Protection," Zoran Gajic, et al, Cigre Study Committee B5 Colloquium, Sep 20-26, 2015, Nanjing, China.

[4] "Navajo Project Report on Subsynchronous Resonance Analysis and Solutions," R.G. Farmer, A.L. Schwalb, IEEE Transactions on Power Apparatus and Systems, Vol. PAS-96, No. 4, July/August 1977, pp. 1226-1232.