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Geomagnetic Storms and Long-Term Impacts on Power Systems

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December 2011

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Executive Summary

It is widely accepted that the sun can create geomagnetically induced currents (GIC) on the Earth that are potentially damaging to electric power equipment. The frequency, duration, and magnitude of these events are difficult to predict. Additionally, there is disagreement among the scientific and engineering community regarding the likelihood of a catastrophic event and the appropriate protective measures that should be employed to protect the electric power grid from this phenomenon.

One potential scenario of concern is widespread failure of electrical transformers. Because GICs can generate unwanted direct current (DC) in transformer windings, the normally symmetric alternating current (AC) becomes offset. This offset condition drives the magnetic transformer core into saturation, which creates harmonics and leads to transformer overheating. This, in turn, can shorten the life of the transformer insulation. The generated harmonics can resonate with inductances and capacitances in the power system near the transformer, which results in higher-than-nominal voltages that can affect the integrity of the transformer winding insulation. While transformers are designed to operate somewhat beyond nominal ratings, this phenomenon could lead to catastrophic transformer failure if the condition is severe enough. Of concern to the reliability of the bulk electricity system is a common-mode failure (e.g., a very large geomagnetic storm that leads to simultaneous failures of multiple power transformers and significant loss of transmission capability). Given the extensive time to either repair or replace this equipment, a prolonged outage of electrical service could occur. Even the time needed to install spare equipment and develop workaround procedures would be measured in days and weeks, which would have a significant national impact under certain circumstances.

Pacific Northwest National Laboratory was commissioned to study the potential impact of a severe GIC event on the western U.S.-Canada power grid (referred to as the Western Interconnection). The study identified long transmission lines (length exceeding 150 miles) that did not include series capacitors. The basic assumption for the study is that a GIC is more likely to couple to long transmission lines, and that series capacitors would block the flow of the induced DC GIC. Power system simulations were conducted to evaluate impacts to the bulk power system if transformers on either end of these lines failed. The study results indicated that the Western Interconnection was not substantially at risk to GIC because of the relatively small number of transmission lines that met this criterion.

This report also provides a summary of the Hydro-Québec blackout on March 13, 1989, which was caused by a GIC. This case study delves into the failure mechanisms of that event, lessons learned, and preventive measures that have been implemented to minimize the likelihood of its reoccurrence.

Finally, the report recommends that the electric power industry consider the adoption of new protective relaying approaches that will prevent severe GIC events from catastrophically damaging transformers. The resulting changes may increase the likelihood of smaller disruptions but should prevent an unlikely yet catastrophic national-level event.

Acknowledgements

This work was supported by the U.S. Department of Homeland Security. The authors wish to specifically thank Mr. James Caverly, Director of the Partnership & Outreach Division, Office of Infrastructure Protection in the National Protection & Programs Directorate, and Mr. Lawrence Skelly of the Science and Technology (S&T) Directorate for their support. In addition, the authors also acknowledge the technical contributions of Mr. Scott Pugh also from the S&T Directorate.

Acronyms and Abbreviations

AC	alternating current
CME	coronal mass ejection
DC	direct current
GIC	geomagnetically induced current
LASCO	Large Angle and Spectrometric Coronagraph
PSLF	positive sequence load flow
SOHO	Solar and Heliospheric Observatory
SVC	static VAR compensator
VAR	volt-amp-reactive

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1.0 Introduction

A stream of particles leaves the sun continuously, and creates a phenomenon called solar wind. Occasionally, and seemingly randomly, the sun emits not only a steady solar wind, but also a large amount of plasma. Such a release is known as a coronal mass ejection (CME), which also is known as a geomagnetic storm or solar storm. The process is routinely observed by the Solar and Heliospheric Observatory (SOHO), a spacecraft launched in 1995 and located in an orbit between Earth and the sun. Figure 1 shows a CME imaged by the Large Angle and Spectrometric Coronagraph instrument (LASCO) aboard SOHO. Sometimes a CME will leave the sun in the direction of Earth, as shown in Figure 2.

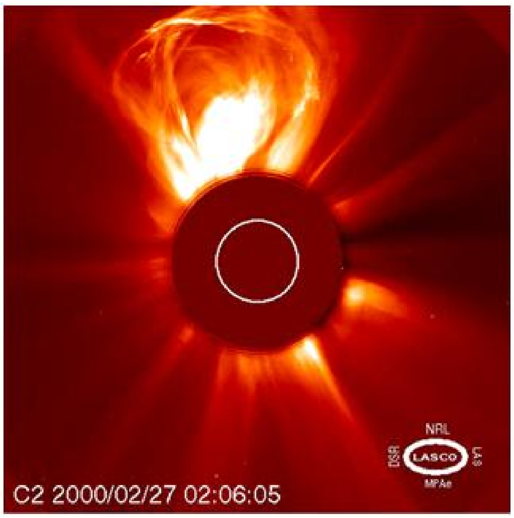

Figure 1. SOHO Image of CME, February 2000

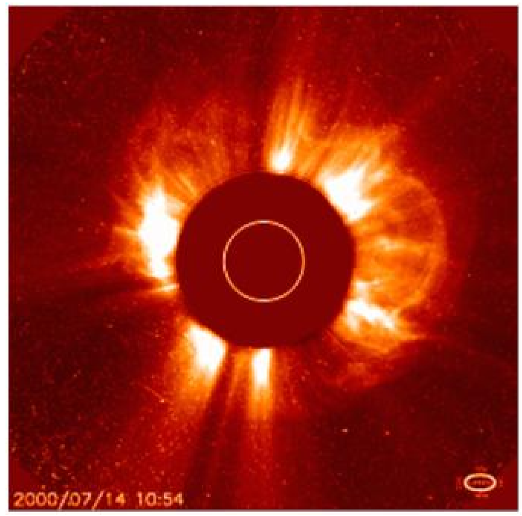

Figure 2. SOHO Image of Halo CME, July 2007

A CME contains between 1 and 10 billion tons of plasma material. It usually travels from the sun to Earth in about 2 days (but with wide variation in transit times), and when it arrives, it is often seen as the Aurora Borealis in the northern hemisphere.[1] The arrival of this mass of charged particles can produce dramatic effects. It interacts with Earth's magnetic field, and can effectively push this magnetic field toward the surface, moving the magnetopause and injecting current into the upper atmosphere.

The effects can take place during any season, and are somewhat independent of the usual 11- or 12 -year sunspot cycle. Figure 3 shows the number of CME events recorded by SOHO over a period of several years. Note: some data are missing for the period in late 1998 and early 1999. Figure 4 shows the same data organized on an annual basis, and also shows the number of halo events recorded during the first 11 years of the period (the halo description is not applied in the LASCO record throughout the entire period).

[1] The same phenomenon occurring in the Southern Hemisphere is known as Aurora Australis.

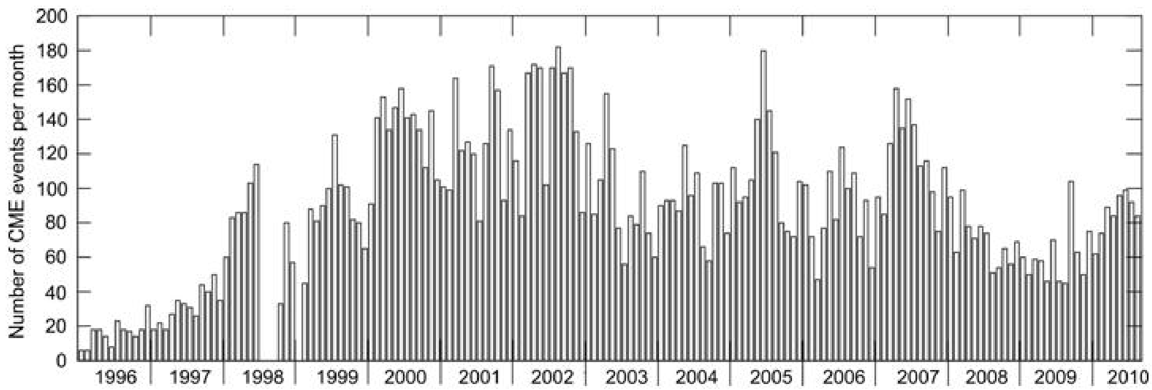

Figure 3. CMEs Recorded by the LASCO Instrument on the SOHO Spacecraft, 1996 to 2010

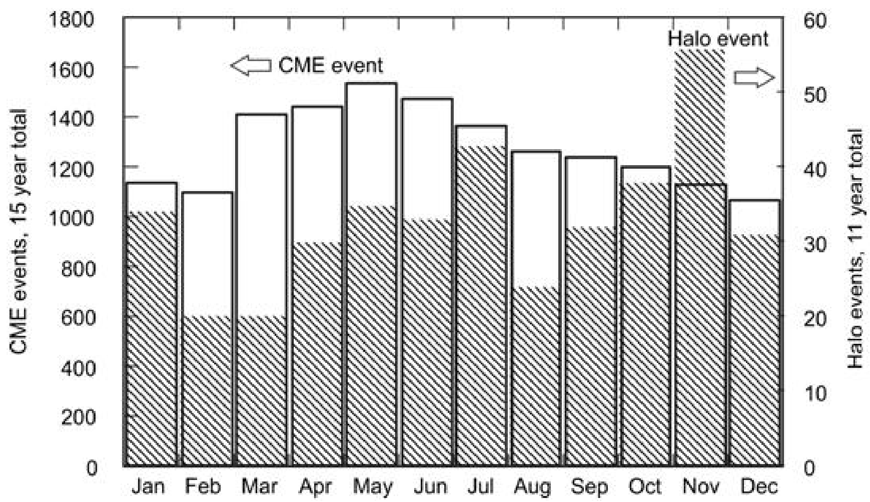

Figure 4. CMEs and Halo CMEs Organized by Month

The severity and timing of a geomagnetic storm appears random. The event that occurred in 1859 was observed and recorded from its outset on the surface of the sun by English astronomer Richard Carrington. That storm, known as the Carrington event, is generally acknowledged to have been the largest in recorded history. At that time, space observations of celestial events and power transmission and distribution systems did not exist, so direct comparisons to modern systems cannot be made. However, the storm disrupted the telegraph system that existed at that time and caused fires in some telegraph offices. The telegraph system was, of course, the only system then in existence that could be compared to today's long power lines.[1] Analysis of ice cores, which can be used to date geomagnetic storm events going back centuries, indicates that storms of the size of the 1859 event are likely to occur about once every 500 years.

[1] In a reversal of roles, Hydro-Québec now uses parts of the telephone system to gather data on the electric field environment created by solar storms.

1.1 Effects of CMEs on Power Systems

Because CMEs are fairly common, it is not rare for them to reach Earth, and their effects on power systems are detected every few years. Effects of CMEs on power systems were observed in 1979, 1982, 1986, 1989, 1992, 1994, 1998, 2000, 2001, 2003, and 2005.[1] Large-scale blackouts happen less frequently, but are a definite risk. Severe CME events occurred in 1859 (disrupting the telegraph), 1921, and 1989 when U.S. and Canadian utilities lost power transmission capability over wide areas. During the 1989 event, Quebec suffered a complete power blackout, resulting in a loss of power for 6 million people. This event is described in detail later in the report.

On the surface of the Earth, the changing magnetic field manifests itself as a slowly changing current that is induced into any suitable conductor. Power transmission lines are vulnerable to this effect if they form a loop with the ground itself, which is often a reasonably good conductor. This vulnerability is manifested especially in long transmission lines that happen to be oriented appropriately with respect to the changing field. The resulting effect is known as a geomagnetically induced current (GIC). Because the magnetic field changes slowly, the induced current is almost always direct current (DC). Because the cross-sectional area of the single-turn loop represented by the power line and a ground return is large, the current produced could be quite large (100 amps would not be considered unusual).

1.2 Transformer Saturation

Because the magnetizing current of even a large transformer is likely to be 10 amps or less, this large quasi-static current moves the operating point of the transformer core toward magnetic saturation. As the alternating current of the power line then adds to the offset, the transformer may go into saturation on part of the power cycle, depending on the design of the transformer.

Electric power is customarily delivered by a three-phase system, but the transformers used may be single-phase (Figure 5) or three-phase (Figure 6) designs. It is common for large transformer banks to be three single-phase units. Figure 6 shows that, in the design known as a core-form transformer, the magnetic flux contribution from a DC GIC would act to produce no net flux.

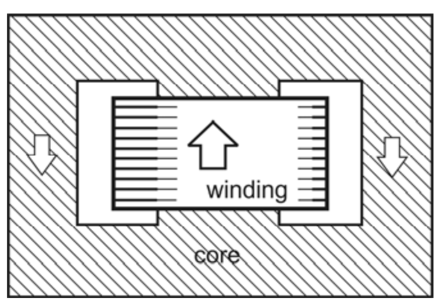

Figure 5. Single-Phase Transformer Configuration

[1] The power system may have been affected by CME events that have occurred since 2005; however, there are no reports of such events in the technical literature. The absence of reported effects may result from the lag between an event and the timing of its publication in the literature.

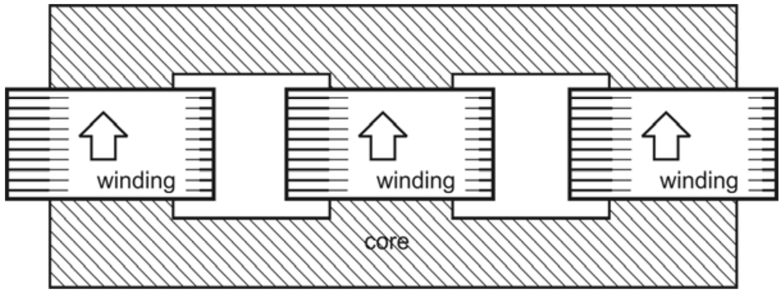

Figure 6. Three-Phase Core Design

Figure 7 depicts a magnetizing current that is rich in harmonics because DC has been added to the AC current in a winding. Generally speaking, the more DC there is, the more distorted and asymmetrical the magnetizing current waveform. In this example, the peaks of the positive half-cycles are about five times the magnitude of the peaks of the waveform with no DC. This ratio is not an unusual figure.

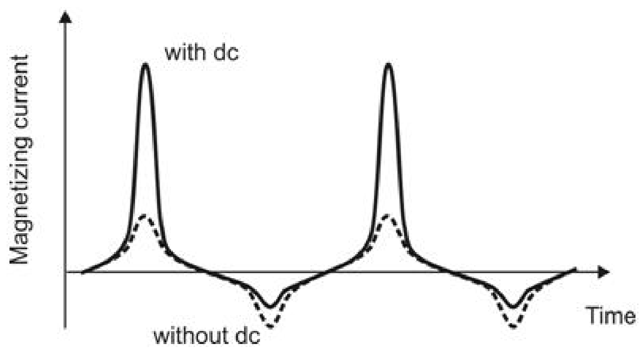

Figure 7. Effect of DC on Transformer Magnetizing Current

1.3 Harmonics

A distorted waveform creates harmonic currents, which in turn generates heat. Albertson et al. (1973) established that localized heating can occur shortly after exposure to a GIC, and the effects may be cumulative. Overheating can shorten the life of a transformer, and if severe enough, it could result in an early catastrophic failure.

In addition, harmonics can resonate with inductances and capacitances in the power system, and can create voltages that are much higher than nominal, which also can lead to transformer failure. Harmonics also might cause erratic behavior in voltage regulators and relays, resulting in system voltage decreases and, consequently, adverse effects of the power transfer capability of lines. In other cases, harmonic blocking measures may be activated, thus preventing some relays from operating when they should, and the harmonics may cause trips that should not happen.

1.4 Short-Term Impacts

Utilities have become experienced in using forecasts to change operating procedures in response to a CME event. Upon learning that a CME event is imminent or receiving telemetry that one already is occurring, a utility or an interconnection can act to reduce their need to transfer large amounts of power.

The degree of reduction that might be possible depends on the way the systems are interconnected, and on the load being served when the event occurs. The problem might not necessarily be worse during peak load periods, when it might be a reasonable assumption that all the generators are running anyway, or during light load periods. Also, because the resistivity of the ground under the lines plays a role and cannot be controlled, there may not be any really good options that can be exercised on all occasions.

1.5 Long-Term Impacts

Transformers are, with a few exceptions, designed to work with no appreciable DC in the windings. Most large power transformers installed at the ends of high-voltage AC transmission lines would fail if a large DC continues for long enough to heat them appreciably.[1] Transmission operators typically have only a few spare transformers that they can use in emergency situations, so transformer damage or failure can become a problem. Obtaining a replacement transformer, or rewinding a failed unit, is likely to take several months or as much as a year.

Smaller devices known as current transformers, which are used for measuring power-system parameters, also would be adversely impacted. In particular, because of their toroidal construction, current transformers would become permanently magnetized. A process of demagnetization would have to be completed before measurements from the transformer could be trusted. Demagnetization is a manual process that might take an hour or so for each transformer affected, but because there are many current transformers in a power system, the overall process could take several weeks. It is hard to say what the effect would be from operating the power system with saturated current transformers; however, operating the system in this situation might be possible, and probably would be attempted by a utility.

[1] Albertson et al. (1973) found that the heating problem is one of local hot-spots, which lead to insulation failure in those locations. This effect could be cumulative, with damage building over many years. Albertson et al. proposed that such problems could be identified by gas analysis

2.0 Mitigating the Effects of GICs with Series Capacitors

Using a capacitor to block quasi-static GIC DC is the obvious solution for preventing problems in transformers during a CME event. DC cannot pass through a capacitor, and very-low-frequency, quasi-static current also is effectively blocked. This solution might not be economical for blocking GIC a few times a year; however, series capacitors can allow a transmission line to carry more power so their use might be attractive to utilities even without considering the possible impact of GIC.

The electrical characteristics of an overhead power transmission line include a series inductance and a shunt capacitance, both of which are distributed along its length. The series inductance, which increases with line length, effectively limits the amount of power that can flow through the conductor. Properly engineered series capacitors can offset this series inductance, and can enhance the power-carrying capacity of the line. The decision to install series capacitors is made when the benefit of this increased power transfer capability offsets the cost. Figure 8 shows a representative power system installation.

Figure 8. Series Capacitor for a Three-Phase High Voltage Power System. The capacitors (and associated communications and control equipment) are mounted on insulated platforms

3.0 Mitigating the Effects of GICs with Protective Relays

System protection implemented by protective relays monitors a system and takes action to mitigate the consequences of off-nominal behavior. Faulted components including transformers also are tripped from the system when a fault is detected. Today, the criteria for tripping a transformer includes detecting an internal fault or an incipient fault that might be detected through a rapid increase in gas pressure within the transformer tank. However, we understand that transformers are *not* tripped today in anticipation of damage that might occur by detecting high GIC levels. If a reliable means of detecting and isolating transformers before incurring severe damage from a GIC were implemented, catastrophic long-term outage scenarios would be ameliorated. Whether this technology could be implemented cost effectively and what unintended consequences might arise from its deployment (e.g., the potential for more frequent cascading failure scenarios, albeit more quickly recoverable) remain open questions.

It is feasible, for example, to detect deviation from an average value of zero for the core-flux operating point in a transformer. Historically, such methods have been used in “fluxgate” devices to detect stationary magnetic fields, and even have been adapted to measure current in a DC power line. It is not obvious, however, whether the technique would be effective in the presence of large and uncontrolled AC levels as well as the DC being measured.

An electronic (rather than electromagnetic) method of measuring large DC levels also exists, and is instructive. It is possible to use a Hall device to measure the flux in a current transformer core, and then to add a *counteracting* flux so the total flux is almost zero. This kind of compensation is routinely used to measure DC or slowly change current with a current transformer. In such a measurement system, the compensating current differs from the current it is compensating for by a constant scale factor determined by the ampere-turns ratio of the transformer. Figure 9 graphically depicts this measurement method.

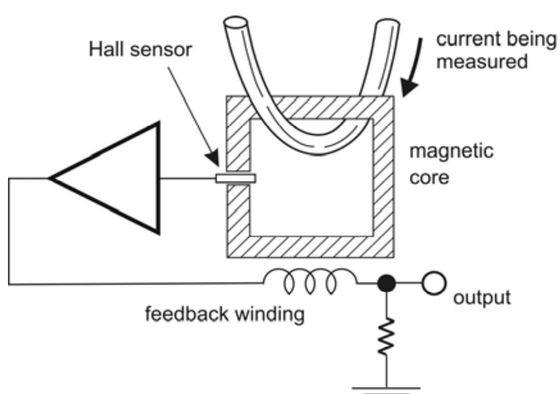

Figure 9. Closed-Loop Hall Measurement Device

As it happens, the measurement relies on the Hall device, which usually is not very accurate. However, it improves considerably over its usual accuracy in this configuration. Because the net flux in the measurement system is zero, the core material is operating in its linear region, and the ampere-turns ratio factor is *exact*. While the original current may be too large to be directly measurable by any "normal" means, the compensating current is an exact, scaled, isolated, and measurable copy.

This principle can be adapted as a way to cancel the GIC-induced flux in a power-transformer core, and the configuration depicted in Figure 9 would apply. However, the ampere-turns needed for the compensating winding would have to be accommodated in the somewhat cramped interior of the transformer. The number of ampere-turns required may be very large, because while the GIC is not large (say 100 amps), it flows in a high-voltage winding that may have thousands of turns. Assuming that there is space inside the transformer, the compensating winding would be a low-voltage winding, with minimal insulation requirements, which would be an advantageous.

An alternative mitigation method would involve inserting a device in the ground path to the star point of the transformers. This device could function by applying a voltage sufficient to cancel out the current. (The closed-loop Hall device cancels out the transformer core flux, but not the current.) Because the current is zero at cancellation, the power involved does not need to be large. However, such a series device would have to be rated for the full fault current where it was installed in the system, and it probably would be in service only when there was a CME warning.

Another option involves waiting until harmonics are detected in the system. This option comes into play when there is assurance that the GIC is large enough to be problematic (indeed, causing transformer saturation). Harmonic detection is routine in power system protection, so equipment that could use this information to provide a valid trip signal already exists.

Thus, either by detecting the DC of a GIC or the harmonics produced in the transformers, protective action *can* be taken. These two techniques are not equivalent: one assumes that, if there is a GIC, action must be taken, while the other waits until there is an undesirable effect before action is required. In each case, a decision between tripping the transformer or tripping the connected transmission line(s), which are the effective antenna for coupling the GIC in the first place, would need to made. The approach taken will vary, depending on circumstances, and the decision-making process was not within the scope of this study.

It may be considered unusual to remove a transformer from service *before* it has failed, but in fact, transformers are often the beneficiaries of this kind of relaying. Some transformers are equipped with temperature measurement equipment that removes them from service before they overheat, and many transformers have gas-pressure relays (i.e., Buchholz relays) that react to slow or to sudden changes in the pressure of the gas above the insulating oil. In many utilities, the gas above the oil is analyzed routinely to detect incipient insulation failure, and if warranted, transformers are disconnected from the system before failure becomes catastrophic. Therefore, disconnecting a transformer based on a GIC measurement is consistent with the existing philosophy of power-system protection. Of course, this kind of power-system protection is not always implemented.

A survey of utility practice could provide useful data. The following questions should be asked at any substation that may be vulnerable to GIC:

- What protection measures have been implemented to disconnect transformers in the event of a GIC?
- Does relaying depend on measured harmonics, the DC in the ground connection, or the DC on the power lines?

- How do the trip settings compare with what is known about the transformer? (Note that the settings on the Hydro-Québec static volt-amp-reactive [VAR] compensators [SVC] were later determined to be too conservative.)

There are several possible ways to implement GIC protection. From many perspectives, the simplest way is to measure the quasi-static current in the ground lead of the transformer. Normally, the power frequency current at this location is small, so the dynamic range required for the measurement also is small. Furthermore, the information is at ground potential, so a large "voltage barrier" does not need to be crossed to connect the information to the relaying scheme. Information obtained using this approach might be better than the harmonic information because by the time harmonics are observed, the transformer certainly has become saturated. However, to trip the transformer before harmonics are observed may lead to a solution that is too conservative, and some unnecessary trips may occur.

Additional protection methods based on measuring the GIC in various *lines* at the station rather than on the ground current in the transformer could be devised. A scheme based on this measurement would allow tripping of only the *line* that was carrying the GIC, instead of tripping the transformers. This action also would protect the transformers. However, several problems exist. First, it is not obvious *a priori* whether the result would be a smaller loss of load than would result from disconnecting the transformers. Disconnecting a transformer has the effect of zeroing out the power transfer from one *voltage* to another at a single location, whereas, disconnecting a line zeroes out the power transfer at a single voltage from one *location* to another. The relative impact on the power system is not obvious. In other words, even if one had the capability to trip the line causing the GIC, doing so may not be the correct action. In this situation, it becomes difficult, if not impossible, to decide in advance how to set the relaying. It may be that some form of adaptive relaying would be adequate, but that would be a major development effort.

Further, measuring a (relatively) small amount of DC in the presence of a larger amount of AC is not a simple matter. It seems likely that the solution would depend on electronics with a fairly large dynamic range to extend the dynamic range of the magnetic device. For example, a closed-loop Hall device that cancelled out the power frequency component of the magnetic flux in a bushing current transformer could certainly be developed. However, it may not be worth considering the development of a DC version of a retrofit bushing current transformer when the information it provides may not be the most useful basis for relaying decisions.

4.0 Relationship Between Outage Duration and Equipment Damage

A 2008 study of the approximately 900 blackouts in the United States during the period from 1984 through 2006 shows that a large percentage were recovered within 1 day, and none went beyond 1 month (Hines et al. 2008). Figure 10 shows the statistics. Note that the vertical axis is meant to be interpreted as "less than" the time shown.

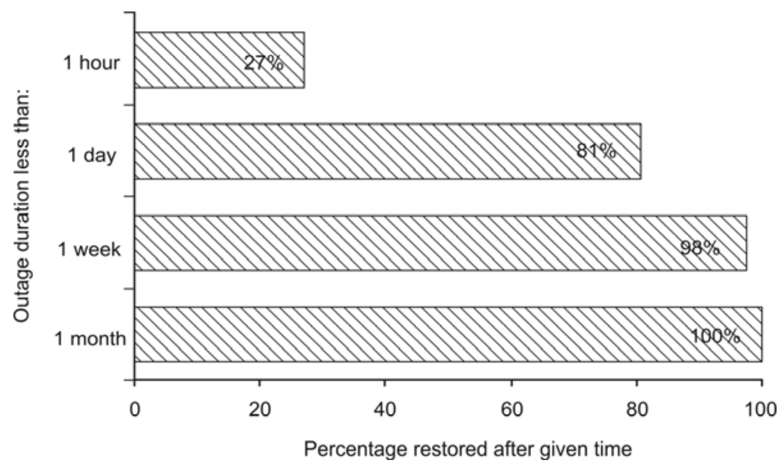

Figure 10. Outage Duration during Blackouts Occurring from 1984 through 2006

Detailed information about a few outages has been collected and is presented in Figure 11. Two of the entries are for the same ultimate cause, the CME event of March 13-14, 1989. One entry is the tripped SVC, and the other entry is the generator step-up transformer. Because one entry required replacement, the time required to achieve recovery was longer. (Note that the vertical scale is logarithmic.) The construction of a new transformer (the last entry in the figure) can take up to 1 year.

We concede that these reflections on the statistics of transformer failures are merely informed opinion. There is no solid information available on what might happen in a Carrington-like event; however, we can assert that it is possible to protect transformers in a system from damage should such a CME event occur.

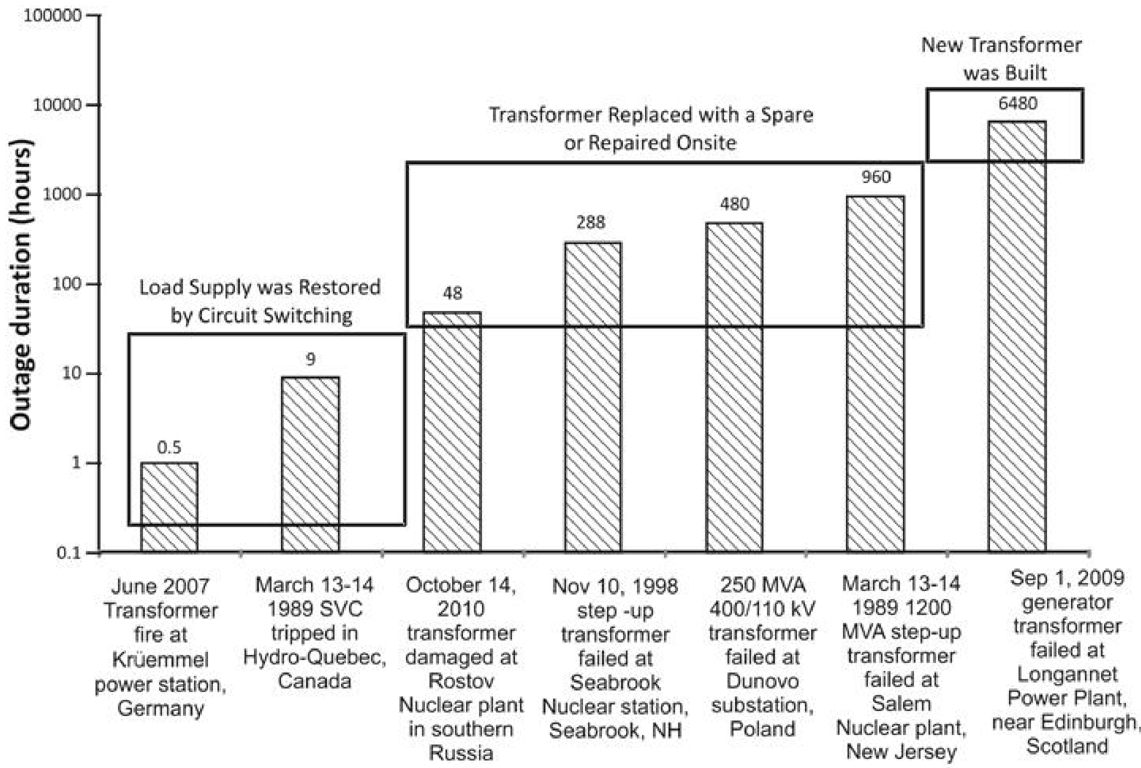

Figure 11. Interruptions Causing Outages

5.0 Examples of Prior Utility Experience with GIC

Because GICs tend to have a greater impact at higher latitudes, it should not be surprising that both case studies presented below occurred in Canada.

5.1 Case Study: British Columbia, Canada

In 1989, BC Hydro reported on the effects of GICs in their 500-kV system (Boteler et al. 1989). (Publication of the paper lagged the storm that it described by exactly 10 years.) This paper was probably the first report of harmonic-level measurements actually made in a power system. BC Hydro studied one line of their system, an east-to-west line between stations named Williston (at Prince George) and Terrace, 450-km west. Intermediate substations were located 174 and 306 km from Williston. Each substation employed a bank of single-phase, 500-kV, step-down transformers, connected as grounded-Y, with a delta-connected tertiary at 12 kV. (The delta connection is interesting because it results in the cancellation of triple-n harmonics in the magnetic field of the core.) At the Williston end of the circuit, the line connects to a north-to-south line with series-capacitor compensation that would block GICs.

GIC levels of up to 10 amps per phase (meaning 30 amps in the connection to ground) were measured using Hall-effect transducers, and a clear correlation with the levels of second and third harmonics in the phase current was observed. Curve-fitting produced a simple relationship between the Williston GIC and 120-Hz current; the 120-Hz current was 95 percent of the GIC. (The slope for the third harmonic was lower, at 15 percent, and there was a constant third harmonic as well.) Because the transformers were autotransformers (as would be expected), the current in the series winding was higher, at about 13 A/phase.

Modeling results showed that, because of saturation, the excitation current increased from 0.32 to 35 A, with peak values as high as 150 A. Transformer reactive power demand (measured as VAR) reached 15 MVAR. (The bank was rated at 1200 MVA.)

The harmonics had the effect of causing the line to relay twice during the CME event. The problem was traced to a relay intended to detect negative sequence currents. A second-harmonic filter was added after the event, and when the paper was written, it was thought to have solved the problem.

5.2 Case Study: Hydro-Québec, Canada

On the morning of March 13, 1989, the Hydro-Québec system was affected by a GIC. At 02:44:17, an SVC system at the Chibougamau substation was relayed off-line by harmonic current protection. At 02:44:19, a second SVC was relayed out of service at the same station. At the Albanel and Nemiskau stations located 150 kilometers away, four more SVCs went off-line at 02:44:46. At 02:45:16, an SVC at the Laverendrye complex south of Chibougamau tripped out. With the loss of voltage regulation on the 735-kV network, a series of lines opened, and within 1 minute, the La Grande Hydroelectric Complex in the north was disconnected from load centers in the south. The SVCs that tripped and the lines that opened are shown in Figure 12 along with the major pre-disturbance power flows.

In Figure 12, the lines that tripped are represented by the dotted lines. With these lines in an open circuit state, and with the SVCs disconnected, the line capacitance caused overvoltages at a number of locations, and some equipment sustained damage. As far as can be ascertained, no damage to equipment resulted directly from the GIC. Perhaps the protective relaying system acted prematurely to protect the SVCs, thereby allowing over-voltages to develop after the load was lost. However, for the most part, the relaying system protected the SVCs from damage, which is its purpose.

This series of events constituted more than the set of contingencies with which the system was designed to cope without losing load. The system abruptly lost almost 9.5 GW of generation, which was about half the total system power at that time early in the morning. The frequency became so extreme that various load-shedding devices distributed around the system began to disconnect load to restore balance between the existing load and the remaining generation capacity. However, relay settings could not handle the step change in power and the resulting change in frequency, and the entire system cascaded to zero power. By 02:45:32, the Hydro-Québec power system was in a blackout, which affected most of the 842,000 customers in the province (almost 6 million people).

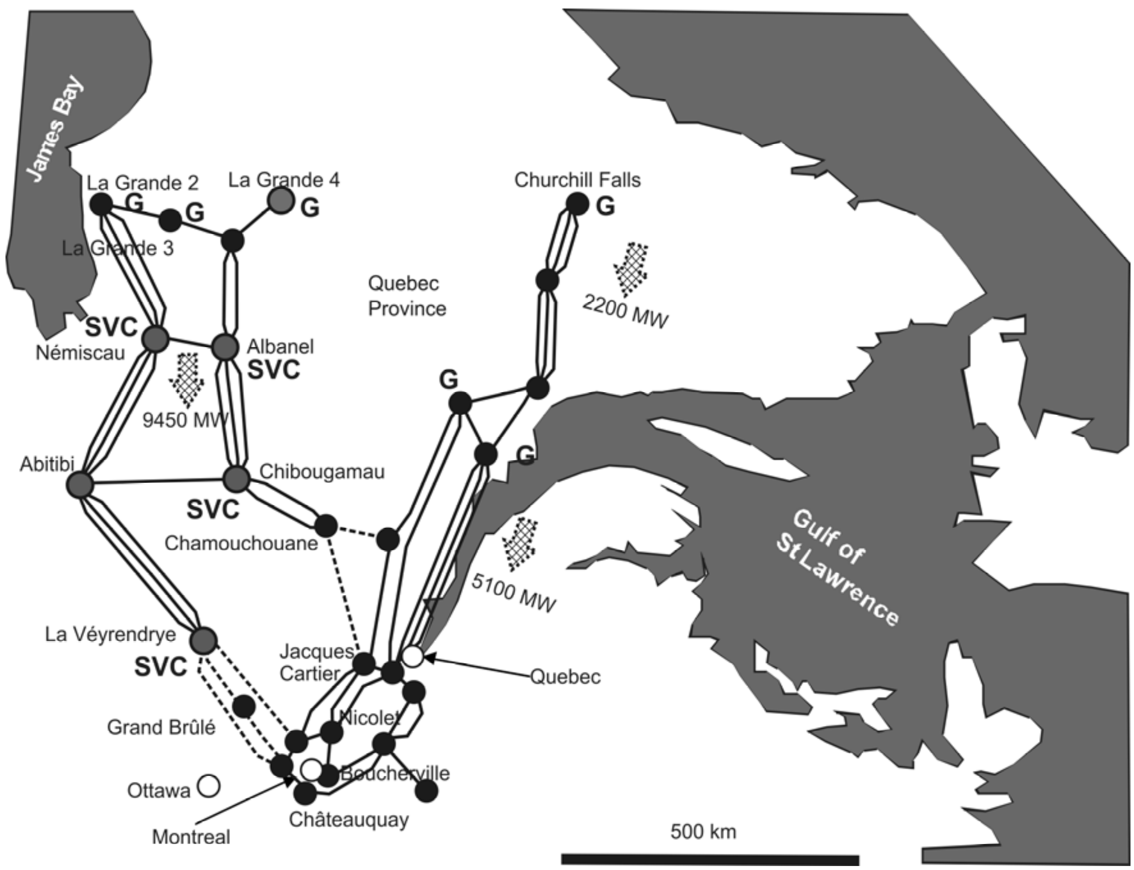

Figure 12. The 735-kV System of Hydro-Québec in March 1989

5.3 Hydro-Québec Follow up

After the March 1989 event, Hydro-Québec undertook a number of investigations and implemented a number of changes. In particular, the following issues were addressed.

- The SVCs were found to be capable of handling the GCI effects but the settings did not allow them to provide protection. Therefore, the settings on the SVC protection system were changed. If the settings had been at the new levels at the time of the GCI event, none of the SVCs would have tripped.
- Two SVCs were added, making the total number of SVCs installed in the system 11.
- Large power transformers were found to be much more tolerant of DC in the windings than had been expected. Experiments showed that DC did heat the transformers, but the most vulnerable part was the tie-plate, which is a relatively simple mechanical part that could be made of nonmagnetic material. Tie-plate heating is not considered to put the transformer at great risk of being damaged.
- A scheme for blocking DC in transformer neutrals was developed, and a pilot was installed. However, the need for such a scheme may be diminished because Hydro-Québec also installed series compensation capacitors in most of the long lines in the 735-kV network.
- As shown in Figure 13, capacitors are now installed. In fact, this change had been planned even before the March 1989 GCI event. Note that Hydro-Québec considers that east-to-west is the "favorite direction" for electrojets, which are the high latitude currents caused by the CMEs. Therefore, it is the least favorable directional orientation for power lines. However, the east-to-west lines at La Grande are low-voltage lines and are relatively short. Based on this understanding, Hydro-Québec mainly compensated the longer north-to-south lines.
- The following guidelines were developed for operating the system during a CME event:
  - Spread generation evenly rather than rely on large power transfers
  - Increase spinning reserve for a fast response if a generator is lost
  - Put as many lines as possible in service
  - Reduce flow on transmission lines to levels below their rated capacity
  - Suspend testing
  - Change SVC protection to "alarm mode" and do not allow tripping
  - Reduce switching operations as far as possible.

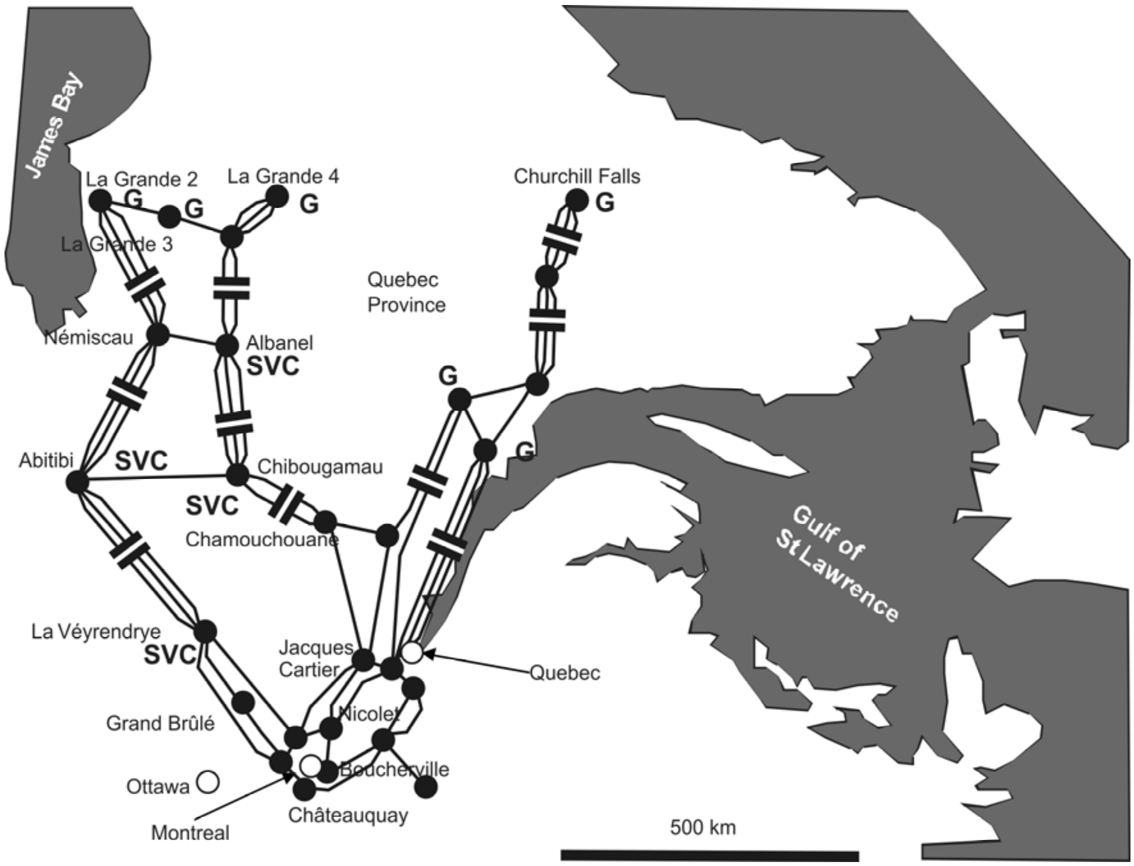

Figure 13. Hydro-Québec System Showing Location of Series Capacitors

Based on the March 1989 experience, the following lessons were learned:

- Events propagate fast once the protection system begins to act.
- Protection systems are made to protect equipment, but generally are not made to cope with large disturbances.
- Cascading can result from protection system actions that could be considered to be “correct.”
- Because the protection system worked, there were no GIC-induced failures.

Recovery from the blackout took no more than 9 hours for most Hydro-Québec customers. By 11:00 on March 13, 1989, power had been restored to all but 3500 customers (less than 0.5 percent of the total number of customers).

As these events were unfolding in the Hydro-Québec system, the GCI was impacting power systems further south in the United States. In the PJM Interconnection system, SVCs also tripped out and a generator step-up transformer at the Salem Nuclear Plant in southwestern New Jersey failed. However, there was no major blackout, and the affected transformer in the PJM system was replaced quickly with a spare.

6.0 Study Example: The Western Interconnection

The Western Interconnection covers an area from the states bordering the Pacific Ocean to New Mexico, Colorado, Wyoming, and Montana in the east, and from Alberta and British Columbia in the north to the Mexican border in the south. There is a seasonal north-south power flow that takes advantage of the various resources and load diversity within the system.

In our study, we looked first for long high-voltage transmission lines (greater than 150 miles). Then, we excluded any lines with series compensation because those lines would not be affected by GICs. We found nine long high-voltage lines that did not have series compensation.

With the exception of two 345-kV lines, the power lines chosen for this study are not near each other. Therefore, we considered that a disconnection of any one or two or perhaps even three of the transformers at the ends of these lines could be tolerated by the power system without risk of a consequent reaction, such as cascading.

A computer simulation was performed in which all transformers adjacent to these lines were removed from service. The simulation employed the well-known positive sequence load flow (PSLF) computer program developed and supported by General Electric-Energy. The result of this simulation indicated that only about 3% of system generation and less than 0.3% of the load was lost. Also, no pockets of un-served load were identified.

To verify that the system was still in reasonable condition after such outages, we re-ran these cases to determine if cascading effects could be induced. To simulate potential cascading effects resulting from severely overloaded transmission lines, we tripped out all the lines and transformers that were found to be operating at more than 120 % of their rated power. No cascading effects were observed.

6.1 Substation Issues

In our PSLF study of the Western Interconnection, we assumed that, if a line was 150-miles long (or longer) and was not compensated with series capacitors, the transformers at the ends of the line would be disconnected. This is a worst-case scenario in terms of disconnecting transformers.

We considered the case of a representative substation where of two 345-kV lines coming into the station, one of these lines is the cause of the GIC problem for the station. In our study, we assumed that the GIC caused one or more of the transformers connected to the 345-kV bus to become saturated. Consequently, our assumption was that *all* the transformers on the 345-kV bus would be disconnected.

As a result of that action, the connection to the local 138-kV sub-transmission system was lost, and because one unit was a phase-shifting transformer, the 345-kV lines did not remain connected. That, in turn, meant that a major transmission path was interrupted.

At the other end of the “problem” line, as before, we assumed that, if the line was long enough, all the transformers in the substation would be disconnected. In this case, some of the tripped transformers were generator transformers, so the power from these generators could no longer be inserted into the power grid. The loss of these transformers would be temporary because they could be reconnected as soon as the GIC danger was determined to have abated.

It would be reasonable to ask whether a GIC problem could be attributed to current induced in the sub-transmission system, which, in this case, is a 138-kV system. For,the station considered, it is most unlikely. There are only two 138-kV connections, and both are shorter than the 345-kV line that develops the problem assumed in our study. At this station, there is only one connection to the sub-transmission system and that connection is very short, perhaps one-quarter of the length of the 345-kV line.

In our view, because sub-transmission lines generally are shorter than extra-high-voltage lines, they are not likely to be a matter of concern for GICs. While the possibility of a long sub-transmission line does exist, a study of the details of all the sub-transmission lines in the Western Interconnection was considered beyond the scope of this study. Such a study could be done if funding were made available.

6.2 Overview

The area we studied is quite northern geographically. The northern border of Oregon, for example, is at about the same latitude as the northern border of New York State. Power lines north of this area are extensively series compensated (mainly for load flow reasons), and even in more southern areas,, series compensation is commonly used.

If we make the conservative estimate that all buses at the ends of lines are connected to transformers and configured in a way that makes them vulnerable to GICs, it seems unlikely that they would interact, even if they all failed or tripped off-line. The end result is that GICs can cause problems on the transmission system, but the impacts are unlikely to be widespread. (The same statement could not be for the Hydro-Québec system in March 1989.)

We looked at the Western Interconnection, where there are few transmission lines of any length that are not compensated by series capacitors. For this reason, we do not believe that these few uncompensated transmission lines would lead to widespread problems. However, it is true that there are many shorter lines (e.g., sub-transmission systems) that likely are not compensated. It may be that, in a Carrington-magnitude event, even shorter, low-volume lines would carry enough DC to endanger transformers at substations. It does not seem worthwhile to consider adding series capacitors to such lines, but it would be worthwhile to ensure that protection systems were set to protect the transformers, either by detecting the DC or by detecting the harmonics they produced.

While transformer trips in the sub-transmission system could produce local power outages, cascading is extremely unlikely because it is the transmission system, not the sub-transmission system, that is the interconnected backbone of the grid.

7.0 Summary and Conclusions

Without doubt, a major geomagnetic storm will again hit Earth. It is not a matter of *if*, but *when*. The impact of such a storm on the electric power delivery system may be significant, but based on the results of our study, we found no reason to think it would be catastrophic.

Our investigations show that the two ways of preventing transformer problems caused by GICs are effective. GIC currents are blocked by series capacitors, and the transformers on lines that do not have series capacitors can be well protected by relaying schemes using technologies that already exist.

We have found that, in the Western Interconnection, all but a few of the longer transmission lines are protected by series capacitors. The few lines that are long enough to be impacted by GICs that do not have series capacitors are distributed within the system in a way that suggests they will not have a collective impact even if more than one transformer failed or was relayed off-line.

However, we recommend that transformer protection be extended to include detecting the presence of potentially damaging GICs and isolating transformers to prevent damage. This approach could result in an increased likelihood of temporary blackouts, but it would mitigate scenarios in which long-term outages persist because of damaged equipment.

We have not determined the practicality of this recommendation if it were to be implemented by the North American electric power industry. We recommend that the appropriate federal agencies, according to the range of their jurisdictions, encourage the industry to be aware of GIC risks and to implement reasonable precautions to minimize potential damage.

The following steps are also recommended for consideration:

- Survey the power industry to determine if individual transmission system operators have implemented strategies for minimizing GIC impacts.
- Survey existing transformers to determine the level of GICs induced during routine geomagnetic storm events. From this survey it may be possible to extrapolate these results to estimate the impact of a larger event than those routinely experienced.
- Prepare and disseminate relevant information (such as the findings of this report) to encourage awareness of the issues via conferences and official communications with utilities and their trade associations.
- Develop appropriate regulations that would ensure implementation of a prudent level of action.
- Establish a modest research and development program to evaluate the absolute cost and cost-effectiveness of various GIC protective measures, and disseminate the results as information updates into an ongoing dialog among various stakeholders in the electric power community.

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