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Inrush Current Analysis for Transformers in Isolated Microgrids

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SUMMARY

Transformers may experience increased current when re-energizing them due to the saturation of their magnetic core. This effect is made worse when re-energizing after a short disconnection period, as the residual flux remains in the magnetic circuit after disconnecting, making the transformer go further into the saturation region when re-connecting. In this paper, a study of the Beaver Creek, Yukon, Canada power system with the planned additional three transformers is completed. This study involves simulating the diesel generation plant connected only to the primary side of these transformers to study the amount of inrush current that will be seen by the generation plant. The planned re-energization procedure for this community involves re-energizing the transformers before connecting any other feeders/renewable sources, which follows ATCO Electric Yukon's standard blackstart procedure after a system outage. The results of these studies will aid the utility in determining whether the planned blackstart procedure will cause any issues due to the inrush current with the addition of these large transformers.

KEYWORDS

Transformer, Inrush Current, Remote Power Systems; Isolated Microgrid; Rural Electrification; Power Generation Control; Generation Controls; Load Sharing Controls; Power System Modeling Northern Context

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INTRODUCTION

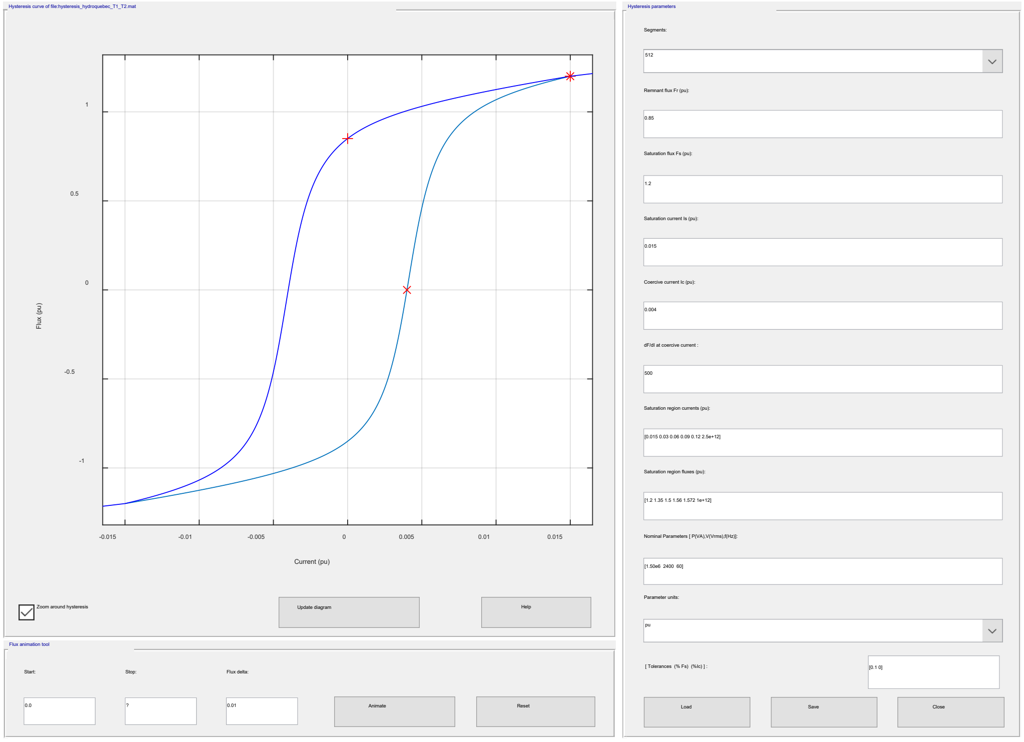
With the planned 1.2MW solar photovoltaic installation with a 3.5 MWh energy storage system in Beaver Creek, Yukon, Canada, the White River First Nation (WRFN) through the Copper Niisüü Limited Partnership are installing two 1.5 MVA transformers and one 150 kVA transformer to interface their Beaver Creek Solar Project to that ATCO Eclectic Yukon's (AEY) isolated electric power system. The addition of these large interfacing transformers to the utility system poses concern for AEY during system start-up, in terms of whether or not the inrush current would cause any nuisance tripping with their protection system or whether there would be any detrimental effects to their diesel generators. This study is a requirement from AEY before the WRFN can connect their solar project to the isolated power system as an independent power producer.

BACKGROUND

The inrush current from transformers comes from the fact that there exists a saturable element within the transformer, namely the magnetic core, that can become saturated when the integral of voltage, or flux, reaches a high value. This saturation causes the transformer to take in far higher current than nominal values for a short period. This can be represented by an effective low impedance magnetization branch on the transformer equivalent circuit during saturation.

As can be seen in Figure 1, the hysteresis curve of a typical transformer displays nonlinear relationship between magnetic flux, $\Phi(t) = \frac{1}{N}\int v(t)dt + \Phi_0$ [Wb], and current, $i(t) = \frac{l}{\mu AN}\Phi(t)$ [A], where N is the number of turns, A is the magnetic area, and μ is the magnetic permeability. As such, the current relationship with respect to time will not be a perfect sinusoidal curve. This hysteresis curve was adapted from [1].

This nonlinear magnetic curve will cause the flux in the transformer to potentially not settle to 0 V·s when the current reaches 0 A, such as if the system is disconnected when the voltage waveform just finished a positive or negative half-wave, as the residual flux Φ_0 will be non-zero. If the system is then reconnected with a 180˚ voltage phase shift, the flux will go further in the saturation region. This flux saturation causes the current in the magnetic circuit of the transformer to greatly increase for the next few electrical cycles, thus causing the high inrush current in transformers.



☑ Zoom around hysteresis

Start: 0.0

Stop: ?

Flux delta: 0.01

Segments: 512

Remnant flux Fr (pu): 0.85

Saturation flux Fs (pu): 1.2

Saturation current Is (pu): 0.015

Coercive current Ic (pu): 0.004

dF/dI at coercive current : 500

Saturation region currents (pu): [0.015 0.03 0.06 0.09 0.12 2.5e+12]

Saturation region fluxes (pu): [1.2 1.35 1.5 1.56 1.572 1e+12]

Nominal Parameters [P(VA),V(Vrms),f(Hz)]: [1.50e6 2400 60]

Parameter units: pu

[Tolerances (% Fs) (%Ic)] : [0.1 0]

Figure 1: Hysteresis curve used in the simulated transformers, along with the per unit values of current and flux.

METHODOLOGY

In this study, the re-energization of the transformers is analysed assuming the N – 1 contingency of loss of the largest generator. As such, only the two smallest generators are active during re-energization. The two smallest generators, GD1 and GD2, have a kVA rating of 356 kVA and 456 kVA, respectively.

Two different cases are studied: The first case involves using the simulated generators from the Beaver Creek community to re-energize the transformers when they have zero remaining flux, as this is what is most likely to occur after a blackout: the transformers will have enough time for the flux in their magnetic circuit to degrade down to a negligible amount before being re-energized. This is the setup requested by AEY. This study involves finding the time at which connection voltage angle causes the worst case inrush current. This was calculated to be when the voltage waveform crosses 0, as this will cause the flux, which is proportional to the integral of voltage, to reach its maximum value at the end of the positive half-wave after reconnecting.

The second case uses the simulated generators from the Beaver Creek community to re-energize the transformer after a very short disconnection period. In this study, the worst-case assumption is made where the flux does not degrade between the disconnection and reconnection times, and a residual flux exists in the transformer core. This should create a worst-case maximum inrush current. This case involves a quick disconnect/reconnect period, thus assuming that the flux at the reconnection time is negligibly different than the flux at the disconnection time. By finding the maximum flux, the transformer inrush current is maximized, and the worst-case scenario achieved. This simulation involves first letting the generators stabilize, then initially energizing the transformer to allow for residual flux to be present. After this initial energization, a set of breakers acting as a re-closer are opened and closed in quick succession to simulate the large inrush current.

The system is modeled as shown in Figure 2. The diesel generator models comprises the synchronous machine, governor, voltage regulator and exciter, and load sharing controls modelled after the existing equipment in Beaver Creek. The generator models use the structure outlined in [2]. The synchronous machine is modelled a 2d1q salient pole machine. The governor is modelled as a simplified version of the GGOV1 model, with only the PID control input to the low value select included in the model [2]. Active load sharing between generators is performed through the ILS1 model, so the supervisory load control of the GGOV1 model was disabled. The voltage regulator and exciter is modelled as a Basler AVC 63-12. Reactive load sharing between generators is performed through RDC1 model, which provides reactive droop as described by IEEE Std. 421.5-2016 [3]. Parameters are as defined by the manufacturers or have been assumed where data was unavailable. Model parameters for the diesel generators are provided in [4, section 2.1].

The generators are connected directly to the 2.4 kV_{LL}, 3Φ 3-wire delta configured distribution system. For both studies, the distribution system is assumed to be disconnected at the feeder relays, with only the renewable plant transformers being energized as per the system restoration sequence provided by AEY. The transformers are connected to the diesel generator(s) using a short transmission line on the primary side, with the secondary side fully disconnected. The line parameters are as provided by AEY. Breakers have been placed between the transmission line and transformers to allow for system stabilization and opening/closing the circuit at the correct timing to ensure the worst-case scenario.

It should be noted that the system restoration proposed by the utility is to restore service to the two 1.5 MVA transformers along with the single 150 kVA transformer, with the solar and battery systems only connecting after the system has been stable and within tolerances for a defined period of time. The service to the two radial distribution system feeders is restored last. The solar plant, battery and the rest of the grid are therefore ignored in this study.

The generator protective relays are time-delayed over current relays with a pick-up voltage of 1.1 pu for GD1, 0.95 pu for GD2 with a time delay of 4 seconds for both. While they are not simulated, it is important to keep them in mind when analysing the transformer inrush current as they are the only protective devices that will be active during the re-energization procedure.

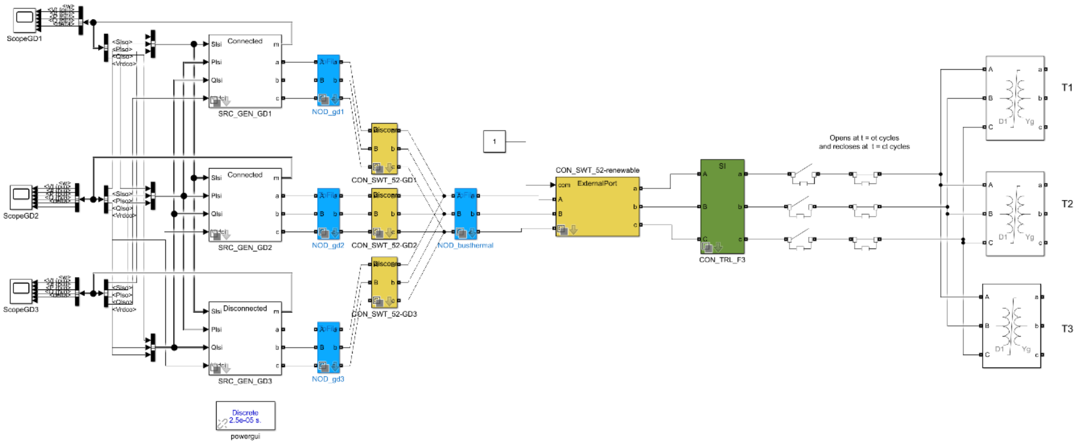


Figure 2: Transformer layout for the Beaver Creek study. T1 and T2 are 1.5 MVA transformers, while T3 is a 150 kVA transformer.

The studies are done through MATLAB and Simulink. The information for the three transformer blocks and their hysteresis curves can be found in [4, appendix A and appendix B]

RESULTS – NO INITIAL FLUX

With an initial flux of 0, the maximum instantaneous inrush current is achieved by closing the breaker after a negative voltage half-wave, as seen in Figure 3. Figure 4 shows the current passing through the three phases, with a maximum inrush current of 156 A.

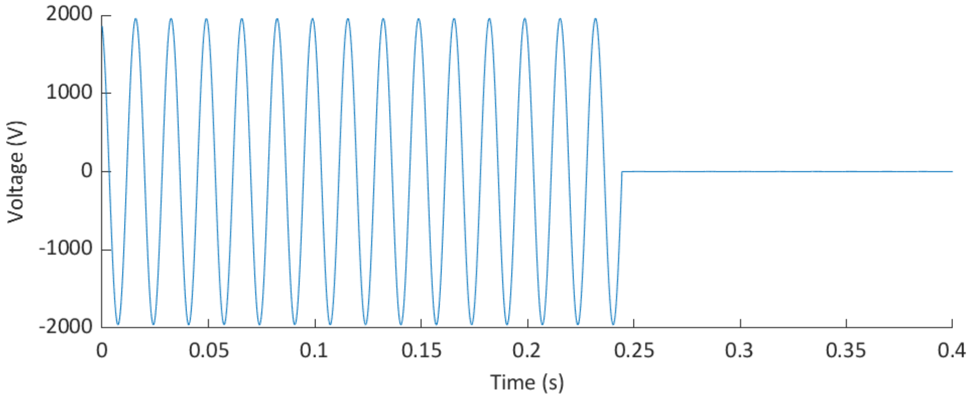


Figure 3: Voltage from breaker, closing after a negative half-wave to cause the maximum inrush current possible. Note that the initial residual flux in the transformer is set to 0, thus causing the flux to reach a maximal value one half period after the breaker closes.

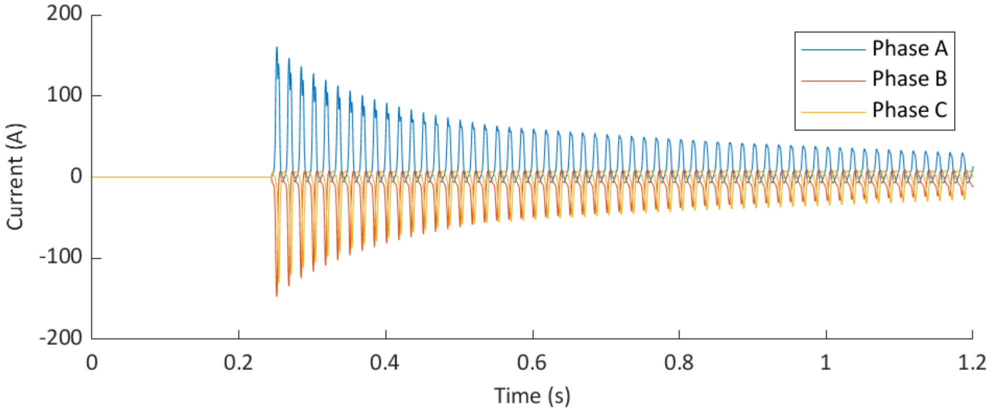


Figure 4: Worst case current in a single phase during the re-energization sequence of the three transformers, going up to 156 A for the first electrical cycle and decreasing exponentially after the re-connection event.

This current, split between GD1 and GD2, is within 1 pu for both generators (see Figure 5).

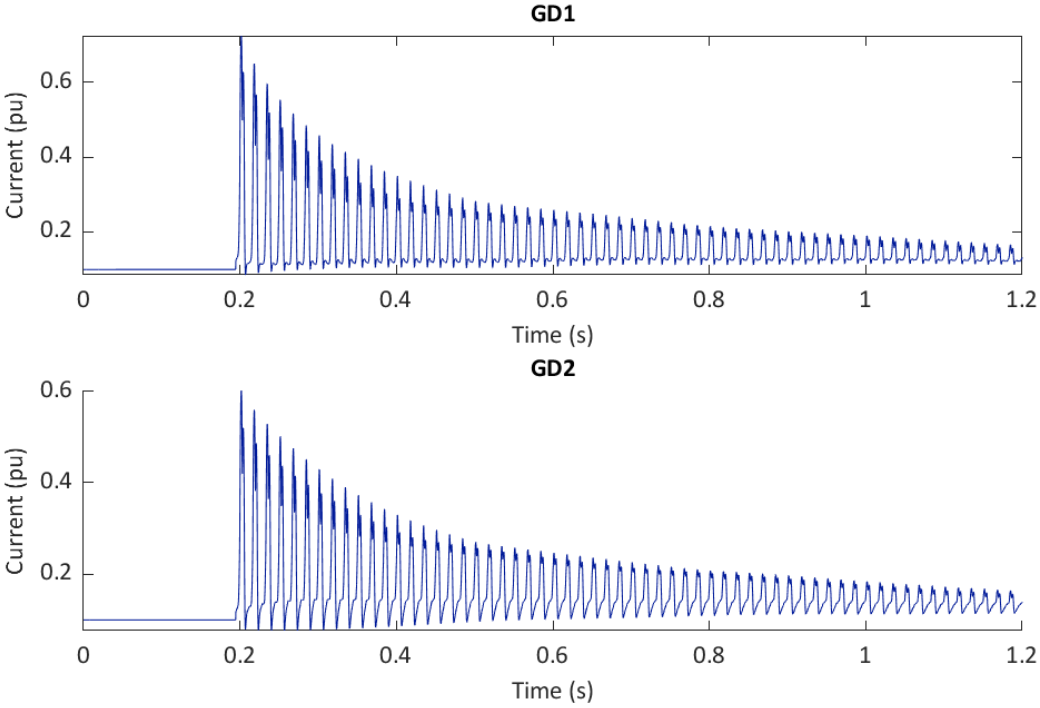


Figure 5: Phase A current from GD1 and GD2, never going above 1 pu. Phase B and Phase C are both lower, as phase A is maximized.

Considering the maximum current of only 0.7 pu for G1 and 0.6 pu for G2, there should be no nuisance tripping that occurs when re-energizing the three transformers with 0 residual flux. Due to this low inrush current seen for the transformers with no residual flux during the re-energization sequence with GD1 and GD2 active, no issues are predicted in terms relays tripping. Additionally, this should not damage the generators in any way due to the low inrush current present in this scenario.

RESULTS – SHORT DISCONNECT-CONNECT PERIOD

Figure 7 shows the voltage as seen by the second set of breakers, opening and closing in quick succession to create the worst case inrush current. As seen in Figure 8, the worst-case transformer inrush current for the three transformers in the Beaver Creek system would be a maximum instantaneous current of 671 A passing through a single phase of the short transmission line.

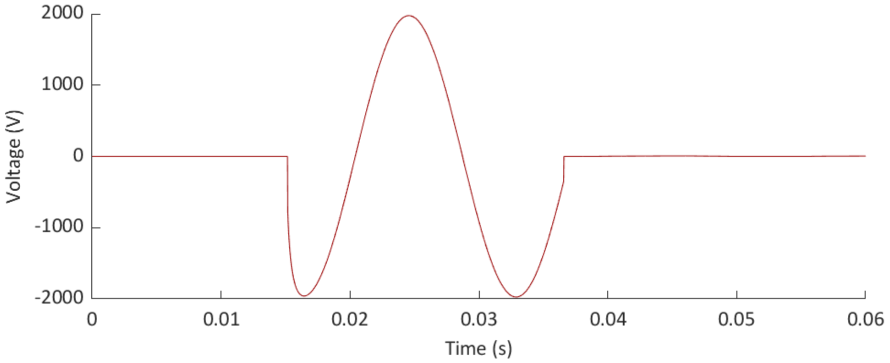


Figure 6: Voltage as seen by the phase A breaker, which opens at a zero crossing, causing the maximum remaining flux, and re-closes with a 180-degree phase shift, causing a maximum inrush current.

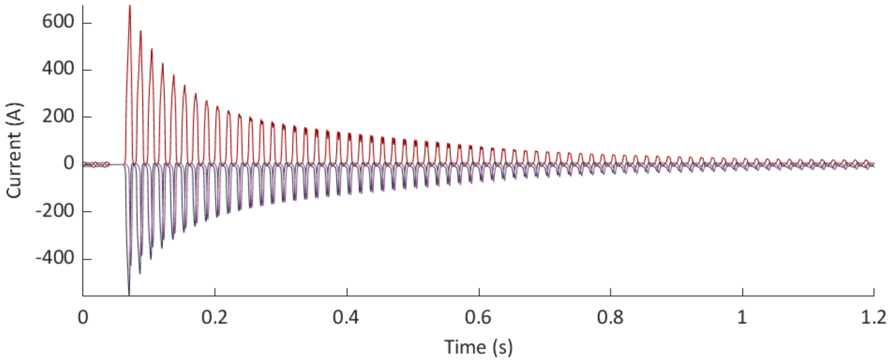


Figure 7: A maximum current of 675 A is seen passing through phase A of the short transmission line after a short disconnect-reconnect occurs before the transformers. Phase B and phase C are both negative with smaller magnitudes of 558 A and 428 A, respectively.

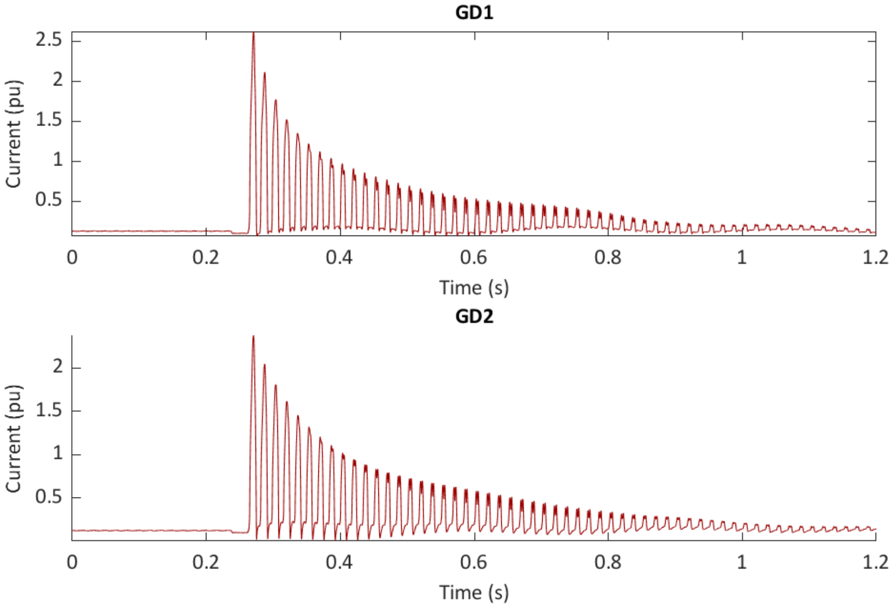


Figure 8: Current in pu for GD1 and GD2. The high inrush current seen around t = 0.3s is the worst-case scenario with a current of 2.74 pu in GD1 and 2.47 pu for GD2. This high inrush current only lasts for at most one electrical period however, which should not cause any nuisance tripping in the system.

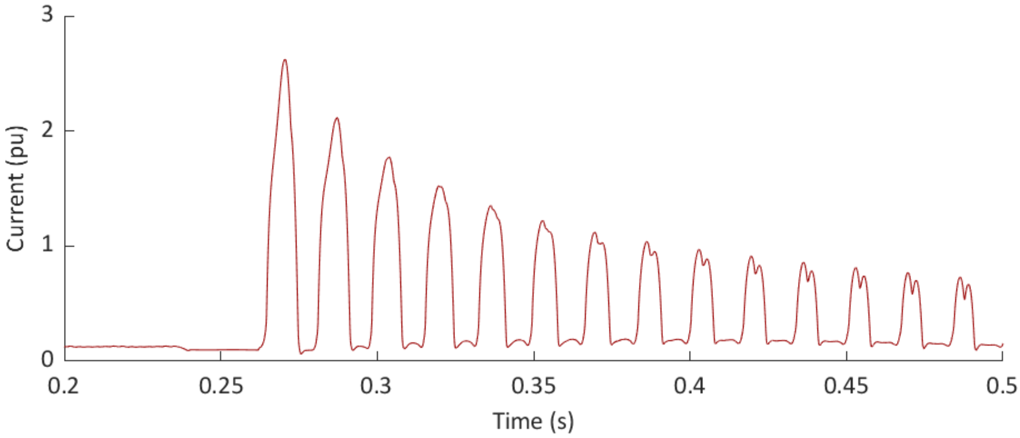


Figure 9: Zoom in of the worst-case current from GD1 for phase A. The high inrush current above 2 pu lasts only 0.004 seconds. As such, this should not cause issues with the protective devices within the generation plant.

This relatively high current in the transformers should not cause issues with the protective equipment as the period of high current is small (i.e., less than 0.01s). As such, even the inrush current from a short disconnect-connect period should not cause any nuisance tripping with these transformer sizes.

CONCLUSION

Both cases saw inrush currents that were sufficiently small in terms of magnitude and/or duration to avoid triggering the generation protection relays. Case 1 only saw the current seen by the generators below 1 pu for both generators, and therefore would not trigger any protection devices between the transformers and the generation plant.

While Case 2 did see current of at least 2.5 pu for both generators, this high current was only present one half of an electrical period. As such, this would not trigger any protective devices between the generators and the transformers since the delayed over-current relays in the gensets require this amount of current for over 4 seconds before tripping. The fact that this large renewable generation project requires significantly larger transformers to interface their project, and that these large transformers are not typically seen in isolated power systems, this dedicated inrush current study was required by the local utility to ensure safe and secure operation of their power grid during system restoration. However, it was shown that the two 1.5 MVA and the single 150 kVA that will be added to the Beaver Creek system should not cause any issues when restoring the grid, even with the N-1 contingency of loss of the largest generator.

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