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Turbine-Generator Topics for Power Plant Engineers: Motoring of a Synchronous Generator

1022588

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1022588
Technical Update, February 2011

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Acknowledgments

The following organization, under contract to the Electric Power Research Institute (EPRI), prepared this report:

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This report describes research sponsored by EPRI.

This publication is a corporate document that should be cited in the literature in the following manner:

Turbine-Generator Topics for Power Plant Engineers: Motoring of a Synchronous Generator
EPRI, Palo Alto, CA: 2011.
1022588

Abstract

This report describes the effects of motoring on the rotors of the turbine and the generator. The causes of damage and ways to protect against it are also addressed.

The report offers recommendations for evaluating damage and inspecting the generator rotor as well as guidance on a protection scheme—including relays—dedicated to motoring protection. Finally, several actual motoring events are described along with their lessons learned.

Keywords
Motoring
Generator rotors
Relays
Synchronous generators
Turbine rotors

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Section 1: Introduction

This material is intended for the new engineer, the control room Operator, Management, or the non-engineer. It discusses the basics, causes, and impact of motoring on the generator and turbine.

What is "motoring" of a synchronous generator; just what does it mean? I went to the IEEE Std.100 "Standard Dictionary of Electrical and Electronics Terms", the term was not listed. Next was the "Oxford American Dictionary and Thesaurus", the term was not there either. So, I took a quick look through a few other handbooks and such, no luck. Then I went to everyone's favorite, Wikipedia. There, almost every reference was to the automobile or transportation. Finally, I went to one of my favorite books, "Handbook of Large Turbo-Generator Operation and Maintenance" (Reference 1), this directed me to IEEE C37.102-2006, "Guide for AC Generator Protection" (Reference 2). In C37.102, in the clause called "Generator Abnormal Operating Conditions", there is a sub clause 4.5.5 called "Motoring", I found the following:

> "Motoring of a generator occurs when the energy supply to the prime mover is cut off while the generator is still on line. When this occurs, the generator will act as a synchronous motor and drive the prime mover."

So, now we have a basic definition for "motoring" of a synchronous generator. Motoring is also referred to as inadvertent or accidental energizing of the generator while at rest or on turning gear.

We all know that a motor and a generator have much in common. You all remember the contributions of Michael Faraday (1771-1867). He was an English chemist and physicist who established the basis of electromagnetic field concepts in physics which formed the foundation of electric motor technology. (Reference 3) Mr. Faraday discovered that if you move a wire through a magnetic field a voltage is developed (induced) on the wire. See the diagram below from Reference 4.

8 Electrical Generation Concepts Chap. 2

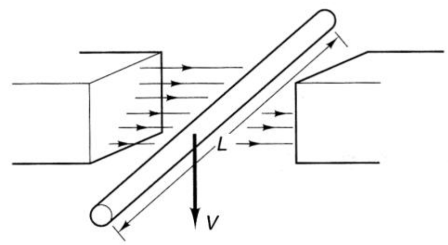


Figure 2.1 Faraday's Law.

Now connect the two ends of the wire to a load and current flows through the load as the wire moves through the field. If you have an electromagnetic field (the rotor winding), a wire (the stator winding), and you supply motion (the prime mover); you have a generator. Now, think of this process a bit differently. Create a revolving electromagnetic field on the stator winding (the wire) by connecting it to the three phase system; this induces a current onto the rotor which develops a field (the field) that revolves with the stator field and we have motion, a motor. Every synchronous generator can operate as a synchronous motor.

Motoring current, current flowing into the generator stator, is quite often referred to as "reverse current". In this document, motoring current and reverse current are used interchangeably.

But, there is more to the story when it comes to synchronous generator motoring; we have to understand all of the conditions of the generator and the turbine at the time of the motoring. That story is the scope of this document; it will concentrate on the effects of motoring on the rotors of the turbine and the generator. The causes, damage, protection, and prevention of motoring are all addressed.

Both motoring currents and negative sequence currents will be discussed here. It is difficult to discuss one problem without the other; they both cause unwanted and harmful current to flow on the rotor forging. Like many maladies there are extremes. Operating with negative sequence currents near the design limit and motoring a unit from rest are both harmful to the rotor, in either case there was over heating of the rotor. One more severe than the other. Here is an analogy of walking and tripping. You can trip on the nap of a rug and fall, or you can trip off the top of the Sears Tower. In either case you fell, one more severe than the other. Photo 1 is an example of a Sears Tower rotor over heating event.

There is no discussion of wind driven generators in this document. That could be addressed in a revised version.

Section 2: Motoring

There are a few basic conditions for synchronous generator motoring. Here is a brief description of these conditions. Each will be discussed in more detail throughout this document.

1. Synchronous Motoring – The generator is connected to the System with load at rated speed, the field is energized, all generator auxiliaries are in operation. Current is flowing out of the generator. If energy to the prime mover is cut off, as in a routine unit shut down, and the generator breaker does not open, the generator stays on line and begins operating as a synchronous motor. The generator can operate indefinitely as a synchronous motor drawing current from the System and spinning at rated speed. The concern here is for over heating the turbine rotor.
2. Induction Motoring – The generator is connected to the System with load at rated speed, the field is energized, all generator auxiliaries are in operation. Current is flowing out of the generator. If energy to the prime mover is cut off and the generator breaker does not open and the generator field is de-energized, the generator stays on line and begins operating as an induction motor with current flowing on the rotor forging. The speed will usually decrease slightly. Damage to the generator rotor depends on the length of time the generator is induction motoring. For a short time, a few minutes, there may be no damage. For a longer time, tens of minutes, serious damage and possible destruction may occur. The concern here is for the generator and turbine rotors.
3. At-Rest Motoring – The generator is not connected to the System and is at rest or on turning gear; the field is de-energized; no generator auxiliaries are in service. Then the generator yard breaker is closed connecting the stator winding to the system. Current will flow into the generator stator and the rotor will start to turn. In this case, even for a few seconds, the generator rotor is almost always seriously damaged and often destroyed.
4. Single-Phase Motoring – Single-phase operation, where one of the phases of the generator breaker does not open, (or does not close during synchronizing) greatly complicates any of the three motoring conditions mentioned above. The concern here is for the generator and turbine rotors.

It is important to keep in mind that motoring can also occur via an auxiliary transformer. However, this current path generally has higher impedance and the motoring current flowing into the generator stator is generally much lower.

Well, just how much current does it take to operate a generator as a synchronous motor and rotate the prime mover at synchronous speed? Below is some general information concerning the amount of current required, based on the generator full load current rating, to operate the generator as a synchronous motor with the prime mover as the load. (References 5 and 6)

- a typical condensing turbine – up to 3%
- a typical non-condensing turbine – 3% to 10%
- a typical hydraulic turbine – 0.2% to 2.5%
- a typical gas turbine – 10% to 50%
- a typical diesel engine – 15% to 25%

If the prime mover, now a load on the synchronous generator, should cause an increase in load, the motoring current will increase above these typical values. For example, if a turbine over heats, expands, and begins to rub it presents an increasing load and the synchronous generator, acting as a motor, will draw more motoring current from the System to maintain speed, just as any good electric motor will do by design.

During "Synchronous Motoring", the generator can operate indefinitely without damage even during increasing load conditions. With the field energized, the rotor stays in synchronism with the system and spins at rated speed drawing a current from the system that is well below the generator's full load current capability. There are no motoring currents flowing on the rotor during Synchronous Motoring. The duration of the motoring event; the design of the turbine; and the turbine operating conditions all contribute to the extent of turbine damage. There have been many Synchronous Motoring incidents where absolutely no damage occurred to the turbine while other incidents completely destroyed the turbine.

During "Induction Motoring", because the generator field (the excitation system) is de-energized, the rotor field decays and the rotor will begin to slow down, no longer able to stay in synchronism with the stator flux. As soon as the rotor speed drops below synchronous speed, induction motor operation begins. The energized three phase windings on the stator create a rotation field within the stator; this field induces flux onto the rotor. This induced flux creates a current flow on the rotor surface. The motoring current is at a frequency of 120 Hz; the current flows on the surface of the forging and only penetrates a fraction of an inch into the forging. The current tries to flow like the current in an induction motor's squirrel cage. The generator rotor slot wedges, (or the forging teeth) and the retaining rings, shrunk fit onto the forging, form the squirrel cage circuit. The geometry of the rotor forging and the slot wedge material resistivity determine the actual squirrel cage circuit. The motoring current induced on the forging will always go to the path of least resistance. The amount of motoring current during Induction Motoring will be higher than during Synchronous motoring, but is not high enough to harm the stator winding. We can not put typical motoring current values on Induction Motoring due to the plethora of generator and turbine rotor designs. There is more information in the Section 3 below, “The Generator Rotor”.

During “At-Rest Motoring” or motoring from turning gear operation, everything is wrong. One of the first things that is wrong is that the generator and turbine auxiliaries are out of service, like lube oil and condenser vacuum, for example. The stator winding develops a large inrush current. It is well known that an induction motor will draw up to six times full load current during starting. But, don’t forget, an induction motor’s rotor is designed to accommodate this high current for the length of time required to reach rated speed without injurious over heating. During At-Rest Motoring, if the generator is connected to a strong system, the stator inrush current will be in the range of three to four times the generator’s rated full load current and the terminal voltage will be in the range of 50-70 % of rated voltage. If the generator is connected to a weak system, the current may be only one or two times rated full load current and terminal voltage may be only 20-40 % of rated. When motoring is via an auxiliary transformer the inrush current may be only 0.1-0.2 times full load current. However each system configuration is different, the inrush current and terminal voltage will be a function of the impedances of the generator, the unit step-up transformer, and the system. (Reference 7) Synchronous generators, aside from hydraulic turbine generators for pump storage operation, are not designed to start as an induction motor. There are some At-Rest Motoring incidents where the generator and turbine approached rated speed. In the Appendix of the IEEE tutorial article of Reference 7, Messrs Mozina and Parr have calculations for determining the amount of inrush current expected for both three-phase and single-phase motoring.

During “Single-Phase Motoring”, one of the three phases of the breaker fails to open or fails to close. Single-Phase Motoring is a very different situation. All of the motoring situations mentioned above are discussed in light of three-phase motoring; that is, all three phases of a breaker stay closed during Synchronous and Induction Motoring and all three phases of the breaker close during At-Rest Motoring. During Synchronous Motoring, single-phase operation will subject the generator stator to a significant voltage unbalanced. This unbalance may produce negative sequence currents as high as 50% of the generator’s rated current. (Reference 8) This is well in excess of the units design capability for negative sequence current (typically 5% to 10%). Significant rotor heating will take place. During Induction Motoring, single-phase operation will only exacerbate an already damaging situation. During Single-Phase Motoring at rest, there may be no significant accelerating torque applied to the rotor. Single phase operation at rest produces both positive and negative sequence currents. For the rotor at rest, these would each look like rated frequency currents on the rotor surface. However, for units with high turning gear speeds the rotor may begin to accelerate. At low rotor speeds the contact resistance between the forging and the wedges will be less while the contact resistance between the forging and the retaining rings will be greater. No clear statements can be made with regards to the location or amount of damage. (Reference 9)

Section 3: The Generator Rotor

There are two basic types or designs of rotors for synchronous generators; the “cylindrical rotor” and the “salient pole rotor”. Each rotor type has an insulated field winding. The cylindrical rotor is used for all 2 pole (3600 rpm @ 60Hz and 3000 rpm @ 50Hz) and 4 pole (1800 rpm @ 60Hz and 1500 rpm @ 50Hz) rotors driven by steam or combustion gas turbines. The salient pole rotor is used on all hydro and most diesel engine driven units where speeds are below 1800 (or 1500) rpm. Below are photos of a small cylindrical rotor and a small salient pole rotor from Reference 10.

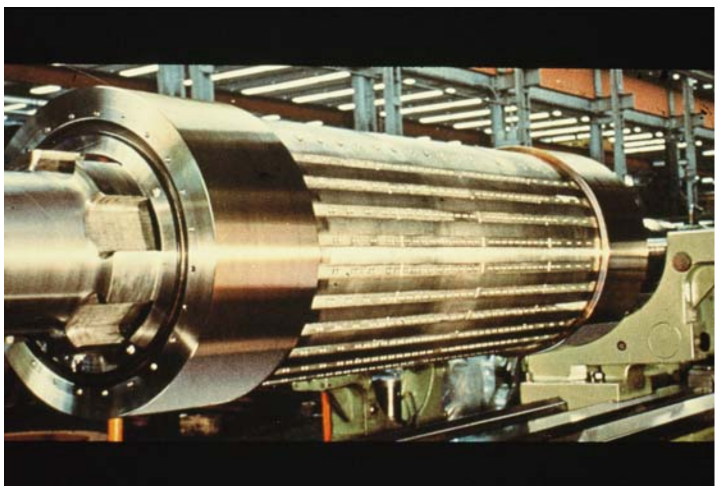


Figure 3-1
Cylindrical rotor

The rotor looks like a “cylinder”. The rotor winding slots and the retaining rings are visible on this small unit.

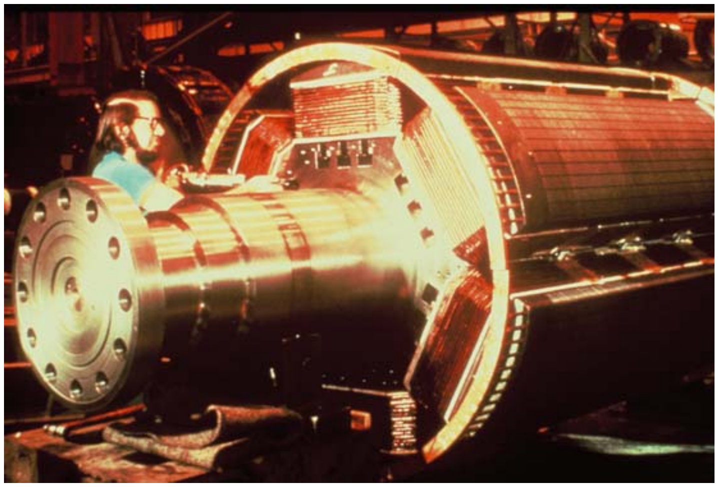


Figure 3-2
Salient pole rotor with a continuous damper winding

This is a 6 pole salient pole rotor. Each distinct field pole and the squirrel cage-like damper winding is clearly visible.

The electrical grid is not a perfectly balance 3 phase system. Even in the best transmission system there are always small amounts of voltage unbalance which cause unbalance currents to flow in the system and the generator. The current is referred to as "negative sequence" (I_2) current. The negative sequence currents in the stator induce a current on the rotor at 120 Hz; the current will flow on the surface of the rotor. This rotor current flows in a pattern like the current in an induction motor's rotor; the current flows axially on the rotor to the retaining ring, circumferentially around the ring to another spot and axially back along the rotor to the other retaining ring, around that ring and back the other way creating a current loop. The size of the loop is dependent on a plethora of issues.

Synchronous generators are designed to accommodate, without injurious over heating, a defined amount of negative sequence current in the stator on a continuous basis. These values, known as "Continuous I_2", are clearly specified in IEEE C50.13-2005 (Reference 11) for cylindrical rotors and IEEE C50.12-2005 (Reference 12) for salient pole rotors. Prior to 1965 there were no design standards for continuous I_2 current. However, C50.13-1965 (Reference 13) did address the short time current capability $(I_2)^2t$. The 1977 version of C50.13 (Reference 14) is the first time that continuous I_2 current was specified as a design criterion in an IEEE standard. Based on their MVA rating, synchronous generators are designed for continuous I_2 current capability ranging from 5% to 10% of full load stator current for both cylindrical rotors and salient pole rotors. The $(I_2)^2t$ ratings range from 5 to 30 for cylindrical rotors and 40 on salient pole rotors.

A typical transmission system may have a voltage unbalance which causes from 1% to 3% negative sequence current to flow in the generator stator. To accommodate these negative sequence currents without injurious overheating, the cylindrical rotor is manufactured with a “damper winding” or “amortisseur winding”. Amortisseur is derived from the French word “mort” or “mourir” which means to die. The damper winding is designed to give the negative sequence current a place to flow without causing over heating. The damper winding is designed to carry the I_2 current mentioned above and dampen any heating effect. Like the rotor squirrel cage winding on an induction motor, the damper winding is not insulated from the rotor forging and is completely independent and separated from the generator field winding.

On a cylindrical rotor, the damper winding is generally designed by creating a squirrel cage-like winding consisting of the rotor slot wedges and the retaining rings. The slot wedges are manufactured from a material that has less resistance than the rotor forging material. We all know that electrons, like good electrical engineers, always take the path of least resistance. It is important to understand the damper winding design on the generator rotor because this is the first place to inspect for visual damage resulting from a motoring situation.

Hydro generators are salient pole machines; they are generally equipped with a pole face damper winding. These pole face damper windings may be connected together, as in the photo above, or they may not be connected. In either case, these damper windings will probably not withstand the over heating from At-Rest Motoring.

Some hydro turbine generator units are used for pump storage operation; the generator, operating as a synchronous motor, is used to pump water back up into the dam. These generators are designed to start from rest as an induction motor; they have a robust copper squirrel cage starter winding (also the damper winding). This winding is intended to start the rotor turning from rest. As the unit approaches rated speed, the rotor field winding is energized and the rotor pulls into synchronization with the system and continues to operate as a synchronous motor. The current in the starting winding fades away at synchronous speed. The presence of the starter winding can significantly reduce the damage caused by some levels of Induction Motoring and At-Rest Motoring on these salient pole rotors.

The arrival of deregulation in the electric utility industry has created some new challenges for System Operators. Generating companies and Transmission companies are now often different entities with differing goals and objectives. Transmission systems across the country are being loaded to capacity; this creates a little more system unbalance and the resulting negative sequence currents.

Section 4: Evaluating Damage and Inspecting the Generator Rotor

Damage evaluation is easy in some motoring situations, once the smoke has cleared. See the first photograph in the Photo Section. But, for a majority of motoring events, generator or turbine damage is not immediately clear; and in many casus no damage or insignificant harm occurs. If other than Synchronous Motoring takes place for tens of minutes, the generator casing may need to be opened for a visual inspection.

The motoring current, like negative sequence current, is at a frequency of 120 Hz; the current flows on the surface of the forging and only penetrates a fraction of an inch or so into the forging. Therefore, except in very severe motoring situations, the rotor field winding and its insulation is not damaged. The stator winding is seldom damaged by Synchronous or Induction Motoring because the currents are well below the generators rated values. Stator winding damage may occur during At-Rest Motoring due to the high inrush of current and, in severe cases, when parts fly off the rotor and hit the stator.

After a motoring occurrence the first step is to review the conditions of the motoring event?

- Was the generator excitation applied?
- Was the turbine generator at rated speed, did it slow down or speed up?
- What was the time duration of the event?
- Were the generator's auxiliary systems in service?
- Were there any generator alarms: high temperature, high current, vibration?
- Were there any turbine temperature alarms?
- Was there negative sequence currents?
- How did the duration and negative sequence current value compare with the design $(I_2)^2t$ capability of the generator?
- What was the result of a review of the relays that operated?

During any severe motoring incident the generator frame may need to be opened for a visual inspection. A mirror, a boroscope, a knowledgeable inspector, or one of the air gap robots may be needed for a rotor inspection. The sketch below identifies the areas to be inspected. There are also a few photos in the Photo Section of this document.

The major areas of concern are: 1) the forging at the ends of the cross slots. [Photos 3 and 4]; 2) the interface where slot wedges butt together [Photo 5]; 3); the interface between the retaining ring fit and the forging or the retaining rings and the wedges [Photo 6]; and 4) the slot wedge to body interface. See the sketch below from Reference 1.

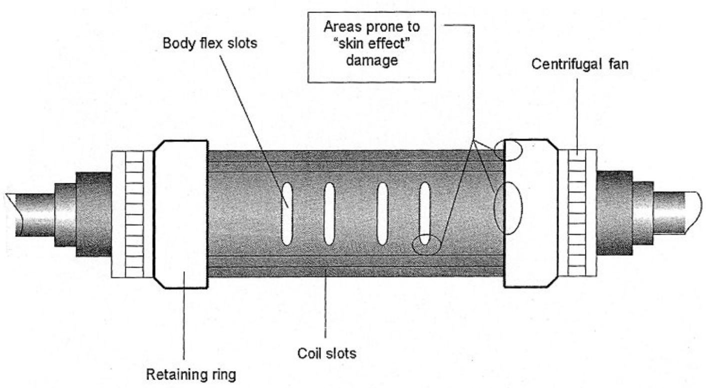


Fig. 4.19 Schematic representation of a turbo-generator's rotor and the areas most prone to be damaged by the "skin currents" generated during inadvertent energization events.

Figure 4-1
Schematic representation of turbo-generator's rotor

The cylindrical rotor forging of large 3600 rpm generators have a design characteristic unique to the 2 pole design. Look closely at the rotors in the generator cross sections below for a 2 pole and a 4 pole rotor. (Reference 1) You can see that the vertical stiffness of the 2 pole rotor is greater than the horizontal stiffness, while the 4 pole rotor is symmetrical in both axes.

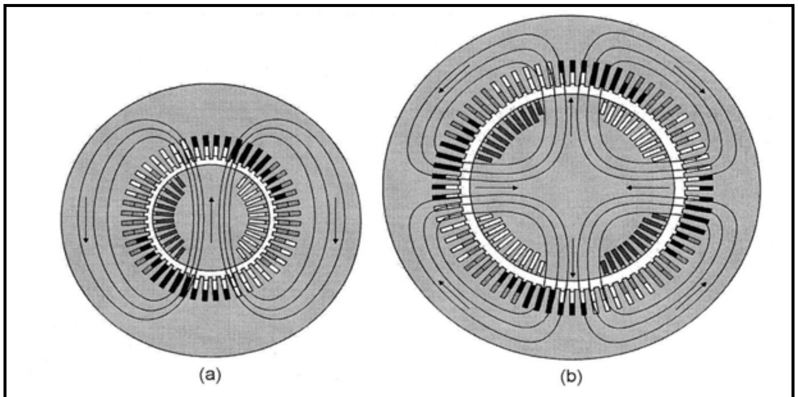


Fig. 2.9 (*a*) Two-pole generator flux pattern. (*b*) Four-pole generator flux pattern.

Figure 4-2
(a) Two-pole generator flux pattern, (b) Four-pole generator flux pattern

On the 2 pole forgings, pole face "cross slots", also called body flex slots, are machined into the forging to balance out the stiffness of the forging. [Photo 2] Motoring surface currents can not bridge these slots; as the current flows axially along the forging it bunches up at the end of the cross slot causing heating. [Photos 3 and 4] This localized heating, if severe, will increase the forging steel material hardness which could become the source for a forging crack. All of the overheated areas on the forging must be checked for changes in hardness.

Section 5: The Turbine Rotor

During a routine unit shut down, the turbine valves are tripped closed. The generator continues to generate for a few seconds as the steam stored within the IP and LP cylinders continues to expand and generate power. As this steam is exhausted the current flow out of the generator decays and current begins to flow into the generator, at this point the generator is motoring. This is good. When the reverse power relay detects current flow into the generator, it confirms that all steam valves are closed and it is safe to disconnect the generator from the system with no risk of overspeed, the generator breaker is then opened. In most cases, the generator breaker should open within 1 or 2 seconds of reverse power being detected.

The most common motoring scenario is when the generator breaker does not open during a unit shut down.

Many discussions of motoring begin by saying “Motoring protection is for the benefit of the prime mover or the system, and not the generator” (Reference 5). Another source provides a very similar statement, “The protection here is primarily for the prime mover or the system rather than for the generator unit.” (Reference 6) These statements are based on Synchronous Motoring which has no ill effects on the generator because the motoring current in the stator is generally less than 5% of the units full load rated current and the rotor spins at rated speed.

For a turbine in normal service, much of the heat generated by windage losses in the turbine blades is carried away with the steam flow. In a motoring condition, where the turbine is being driven by the generator, and the steam flow is stopped, the turbine becomes a fan, and the windage loss heating is bottled up within the turbine casing. This heat can build up to excessive temperatures and serious overheating will take place on the turbine exhaust hoods and the turbine blades, causing expansion, often resulting is damaging rubs or destruction of the turbine. The high pressure turbines and the 1st reheat turbine on double reheat units are particularly susceptible to this windage overheating.

When steam flow is completely lost during a motoring situation, turbine damaged may occur in as little as 30 seconds or take as long as 30 minutes depending on the turbine design and the turbine operating conditions during the motoring event. Motoring damage to steam turbine cylinders usually occurs at 2/3 to 3/4 of the way along the steam path. The rate of heating depends on the blade length so it is lowest at stage #1 and highest at the last stage. The reason that the worst damage may not occur at the last stage (longest blade) is thought to be due to the fact that the last stage is next to the exhaust where steam in this area recirculates with the exhaust steam and receives a degree of cooling. Turbine damage from a motoring event will be very case specific and can range from inconsequential to catastrophic.

General Electric designs the high pressure turbines with a “ventilator valve” which provides a small amount of steam flow, from the reheater exhaust section of the boiler, to release the energy in the high pressure stage to provide cooling flow in the event of load rejection or a unit trip. The ventilator valve will only open if the turbine control system is in the tripped mode. The flow thru the high pressure blades is small and meant only to provide cooling as the unit coasts down from rated speed following a trip. During a motoring event, the ventilation valve won't know if the turbine is motoring or not, only if it is tripped or reset. The ventilator valves could be of some benefit during motoring in the tripped condition and the ventilator valve continued to pass steam to cool the high pressure blades. However, these are relatively small valves, commonly about 2 inches.

EPRI 1017492, “Abnormal Negative Sequence Analysis Excel Application Version 1.0, November 2010” is a an Excel based application is intended to be used for assessing the need for turbine generators to be inspected after an abnormal negative sequence or motoring from standstill event may have occurred.

The application has one primary function: estimating the likely impact of any event found on the generator rotor so that a quick informed decision can be made regarding the necessity to perform a rotor dovetail inspection. The inspection recommendation analysis will be based on the likelihood of overheating the generator rotor wedge, non-magnetic retaining shrink fit and pole face with flex slots.

Section 6: Protection

There should be a protection scheme dedicated to motoring protection. It is not good relaying practice to rely on secondary benefits from other relaying to offer motoring protection. Motoring protection needs to be active when the generator is out-of-service as well as in-service. Several relays are available: 1) reverse power relays, 2) negative sequence relays, 3) loss of field relays, 4) breaker failure relays, 5) system backup relays, 6) and, some would say, turbine valve limit switches and temperature sensors on the turbine.

Motoring protection is now state-of-the-art and sequential tripping is well known to relay engineers. (Reference 15) There are several excellent references describing the relay protection schemes to prevent injurious motoring. Keep in mind that motoring protection should not take precedence over overspeed protection. (Reference 15) The major protection for motoring is the reverse power relay, NEMA device #32, "directional power relay." The sensitivity and setting of the relay is dependent on the type of prime mover. A typical condensing steam turbine relay setting might have a current pick up about 0.5% of generator full load current with a time delay of about 30 seconds. This should be enough time delay to insure the turbine valves are fully closed during a turbine shut down to prevent an over speed condition. The time delay is also necessary during synchronizing to the system to allow the turbine controls to pick up load. The reverse power relay is also often used in a sequential trip scheme. A negative sequence relay, device #46, "current unbalance relay" is also useful in evaluating the motoring situations. This relay can also be used to remove a unit from service.

Today's digital relays provide comprehensive primary and secondary generator protection for motoring conditions. Reference 16 is available at www.sweitzer.com.

Please refer to IEEE C37.102-2006 for further information on motoring protection.

During an outage in which the turbine generator will be disassembled, the high voltage links in the buses between the generator and the generator step-up transformer (GSU) must be opened and the generator side of the links must be grounded to prevent At-Rest Motoring.

Section 7: Prevention

The best prevention for motoring is well educated and informed control room Operators. Most motoring situations occur during a unit shut down or routine system trip. If Operators are aware of the overall unit conditions when a motoring situation develops; they can evaluate the generator conditions; and make the correct decision to prevent or mitigate damage to the generator and turbine. Modern power plants have become more complex with the use of the breaker and a half bus arrangement.

The next best prevention activity is a good and well executed equipment maintenance and inspection program. A major cause of generator motoring is a mechanical malfunction in a high voltage breaker.

In Section 8 below there are some actual motoring events experienced by EPRI members. Many of these motoring events come about when, during a shut down, an issue arises concerning the turbine valves (are they fully closed) or the generator yard breaker (are all 3 phases open). Review these situations carefully and explain them to the control room Operators. Unfortunately, some of the events are not fully developed here.

It is suggested that all generators rated above 100 MW be equipped with dedicated motoring protection and negative sequence metering. The negative sequence relay will allow the Operators to see this current and become aware of its existence. The negative sequence meter will provide very valuable information during a motoring event.

During an outage in which the turbine generator will be disassembled, the high voltage links in the buss between the generator and the generator step up transformer (GSU) must be opened and the generator side of the links must be grounded to prevent motoring. Yes, this is a deliberate repeat of the same statement in Section 6 above.

Section 8: Actual Motoring Events

EPRI has collected several actual motoring events and I have added a few from my 39 years with AEP. The situations below do not go into all the details associated with switching the yard breakers, manual disconnects, breaker failure causes, turbine valve limit switch failure, or operator error.

There are no definite "if this, then that" situations that can be provided concerning generator motoring scenarios. The circumstances are legion. We need education and familiarization with motoring to make good decisions. Now, many of the stories below do not contain all of the details or give a complete synopsis of the motoring event or the damage to the unit. Names have been omitted to protect the innocent.

8.1 The unit was being taken off line for some boiler repairs, as per normal procedure the plant output was reduced, turbine steam flow shutoff and the generator CB opened, the plant worked with dispatch to isolate the unit from the system for the boiler repairs. The generator was connected to the system in a typical breaker and a half scheme with and air break switch between the generator and the two unit breakers. The plant operator went to the substation and from the control building operated the air break switch, he received an open indication in the control building so assumed the switch was opened but failed to visually observe the air break switch. Actually the air break did not open because someone had disconnected the motor operator from the actual switch mechanism, so the motor operator went through its travel but never opened the switch. He called up the control room operator and indicated that the generator was isolated from the system, the plant operator gave the dispatcher permission to close the generator CB to complete the bus connection, at that point the generator was connected to the power system. The unit accelerated from turning gear for about 30 seconds, the OEM feels the unit got to about 2000 rpm before the aluminum wedges in the generator field became hot enough that they could not longer restrain the rotor copper and the rotor unwound inside the stator and quickly stopped the rotating assembly, the OEM thinks the unit stopped in about three revolutions. This sudden stop broke bearing caps and launched them outside the turbine building a few hundred feet, the generator hold down bolts were almost pulled out of the foundation, the unit was a total loss. The total outage time was about 1 year.

When it is possible, always get physical confirmation of an activity.

8.2 The event occurred when the unit was being taken off line. The unit was backed down to about 10 MW and the unit was tripped closing the steam valves and opening the yard oil circuit breakers (OCB). Some ten or so minutes after the unit tripped the control room operator noticed that the unit was still at operating speed of 3600 rpm. Technicians were sent out to determine the problem and they found that one leg of the OCB had not opened. Secondary switchyard breakers were opened to isolate the unit from the high lines. The estimated time that the unit continued to spin in the single phase condition was 30 minutes. My comment was that the unit continued to rotate at speed and hence would not have caused excessive circulating currents on the surface of the generator rotor and hence would not have caused any damage. In the case of the OCB not opening due to a mechanical failure, the anti-motoring circuits could have activated but would have only tripped the 86 lock out relay and hence send the trip signal to the OCB. It seems like the automatic or anti-motoring devices would override operator action unless the operators have put the voltage regulator in manual, which takes away some protective devices.

Mechanical failure of a breaker, a maintenance issue?

8.3 This is a small steam unit about 45MW. The site was doing a normal shutdown and the generator breaker failed to open and the site had no breaker failure protection because the next breaker is in the yard and belongs to another group. The excitation tripped 30 seconds after the breaker failed to open. The generator motored for 27 minutes near synchronous speed. No damage was done, the MW and MVAR reading was within the machines capabilities. The reason for the breaker failure was mechanical linkage was bent due to a rubber spacer coming apart and the linkage was being bent to far each operation till it finally did not work. One thing we are thinking we should do is put a B finger from the breaker in series with the trip signal to the exciter. That way if the breaker does not open we can at least keep the exciter at synchronous speed to avoid any induced currents from the stator onto the rotor.

Mechanical failure of a breaker, a maintenance issue?

8.4 While trying to rack down a GE Magna Blast breaker for the unit transformer during an outage, the racking mechanism stuck in the middle of its travel and jammed. The aux bus was energized at the time by the starting transformer. The electrician who was operating the racking mechanism was new, but saw that the springs were not discharged and thought that this might be the cause as to why the mechanism jammed. He therefore tried to discharge the closing springs by pressing the close button on the Magna Blast breaker. This closed the breaker and energized the generator bus through the starting transformer. Another electrician in the vicinity heard the hum of the breaker and generator, and ran over and pushed the trip button on the breaker. The generator was energized for approximately 30 seconds. We were unable to verify whether the generator rolled off gear but suspect not. We also believe we were fortunate that that the energization voltage was at 6900 volts and that there were two transformers in the circuit to limit the current. We decided to open the man-ways for the red iron and try to perform an inspection of the rotor. While there appeared to be some localized heating around the flex slots, we did not see any thing significant. The unit was subsequently energized after the outage without incident.

Mechanical failure of a breaker, a maintenance issue? Operator training.

8.5 The generator breaker was closed inadvertently during a maintenance outage on a 500 MW nuclear plant. Fortunately the turbine generator back-up differential relay tripped quickly (but incorrectly), because of high spill current – the generator and transformer CT's were not matched and the over current was high enough to cause a mismatch and a high spill current. The plant did not pull the rotor and inspect it, arguing it was only a few seconds duration. Two years later the generator was out for a major inspection; they found considerable arc damage and local burning of the retaining rings at the shrink fit to the rotor forging. The retaining rings were replaced at the next major outage.

Operator training or poor communication.

8.6 A severe motoring event took place on a 100 MW unit in the 1970's during commissioning of a new unit. The stator was energized at rest, no protective relays operated. The rotor was driven right up to full speed. The generator rotor was badly damaged and was replaced.

Perhaps a poor relay check-out procedure.

8.7 A turbine tripped. The 132kV circuit breaker failed to open resulting in the generator motoring. Attempts to open the circuit breaker by replacing blown control fuses failed and the generator was eventually taken off line by taking out the main 132kV bus bar to which it was connected. The circuit breaker failed to open due to a jammed mechanical tripping lever which led to burnt trip coils. The shutdown sequence operated correctly up to and including the operation of the reverse power relay. The sequence failed to complete when it reached the stage with the turbine valves closed, the reverse power trip generated the excitation contactor open, but the 132kV CB still closed. The generator motored with no excitation for 1 hour 13 minutes. Unit protection does not clear the bus bar when the circuit breaker fails to open. A generator rotor inspection has been scheduled nine months after the incident to inspect for damage, mainly from the effects of induced and negative sequence currents. [Don't know the outcome of the inspection.]

Poor maintenance of breaker and relay.

8.8 A single phasing event was due to a failure of the switchyard isolator to open all three phases. One phase of the motorized disconnect switch failed to open completely after a remote control command to open the disconnect switch. The operator activated a trip when there was a large flash in the switchyard from the arcing disconnect, opening the field breaker, but the generator breaker on the grid side of the disconnect did not trip due to a protection design. When the field breaker opened, the steam valves closed (with the generator connected) and the generator motored for 33 seconds near rated speed (3400rpm?). The sister unit provided the majority of the negative sequence current to U2, when the last switchyard breaker tripped from a neutral over current relay operation, finally disconnecting U2 completely. The site management decided the rotor did not have to be inspected and returned the unit to service. An inspection a number of years later showed arcing on the wedges and slots. This (I2)2t was estimated by the OEM anywhere between 3 and 9.

Mechanical failure of a breaker, a maintenance issue?

8.9 During an outage on a 935 MVA unit a switchman was dispatched to open a disconnect switch so the yard could be reenergized. For some unknown reason, he left the disconnect switch in a "nearly closed" position and locked it into place. The Control Room Operator then closed the breaker to energize the yard which energized the stator through the arcing nearly closed disconnect switch. The stator was energized for 16 seconds and the rotor reached 700 rpm. The rotor was inspected; there was significant heating at the pole face flexibility slots; arcing at the retaining ring shrink fit to the forging; and arcing at the slot wedges and forging. The heat affected material at the flexibility slots was machined out by the OEM. The retaining rings and all slot wedges were replaced. After a 4 month outage the unit was returned to service. Three years later the rotor was removed for an inspection, no abnormalities were noted. Then, 5 years later (8 years after the motoring incident) the rotor was pulled during a major inspection. Cracks were found at two of the flexibility slots, one crack was significant. An ultrasonic inspection hole was drilled near this crack. The crack was 1.22 inches deep. There had been no vibration problems with the rotor. The generator was returned to service and fitted with extensive vibration instrumentation. A new rotor was ordered. The new rotor was installed after 16 months. The crack in the original rotor was again inspected via the ultrasonic inspection hole. The crack had not grown in the past 16 months. The original rotor remains at the plant as an emergency spare.

When it is possible, always get physical confirmation of an activity.

8.10 A combined cycle unit, 2 gas turbines (G1 and G2) feeding 1 steam turbine (S1) through a HSRG boiler. All three generators are hydrogen cooled. The G1 gas unit tripped. The control room Operator was busy trying to balance steam flows from the other gas unit (G2) to maintain flow to the steam unit and did not notice that the tripped gas unit, G1, was still at speed in a Synchronous Motoring condition. Once the motoring condition was noted, another operator was sent to the switchyard to investigate. The G1 yard breaker had not opened. Due to some miscommunication, the field of the motoring unit, G1, was de-energized. The G1 unit then began Induction Motoring. The turbine overheated causing high vibration. The high vibration caused the generator bearings to rub causing an oil fire at both generator bearings. The generator rotor was designed with hydrogen blowers on each end and the hydrogen gas flow for both fans was from the ends of the stator frame toward the middle of the stator. Because of the high bearing vibration, the hydrogen seal oil rings failed and the rotor mounted fans sucked the oil fire flames into the stator frame at both ends. The hydrogen began to burn. There was no hydrogen explosion.

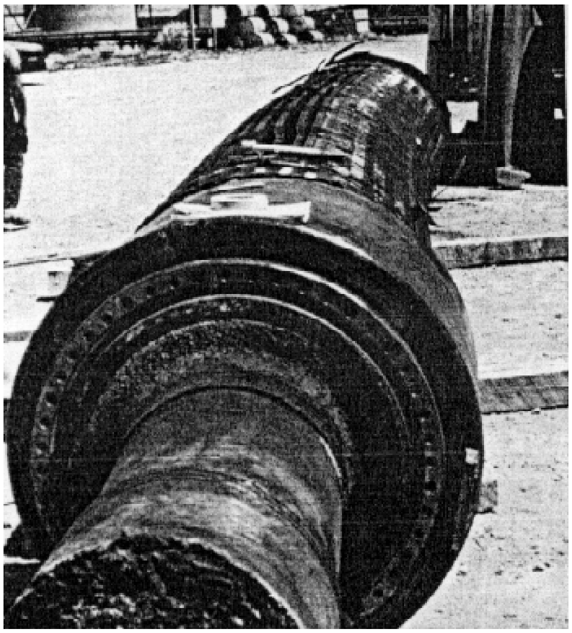
Both stator end windings were badly charred by the fire; the core iron was not damaged. The stator was rewound. As mentioned above, the motoring currents on a combustion gas turbine can be up to 50% of the generator full load current. This heavy Induction Motoring current welded both retaining rings to the rotor forging and damaged the field windings. The rotor was almost scrapped. The rotor was rewound and new retaining rings were installed.

Operator training or poor communication.

8.11 During a routine shut down, a large cross compound unit (2 × 720 MVA) was operating in a Synchronous Motoring condition while trying to confirm the full closure of a high pressure turbine stop valve. Once the turbine valve closure was confirmed the unit was tripped from the system. The unit motored of 22 minutes with no steam flowing through the turbines. On coast down the high pressure turbine came to rest very quickly and could not be rotated on turning gear. Upon inspection, the high pressure turbine was badly damaged due to overheating. The high pressure turbine was replaced at great expense.

Operator training may have prevented this damage.

Section 9: Photos

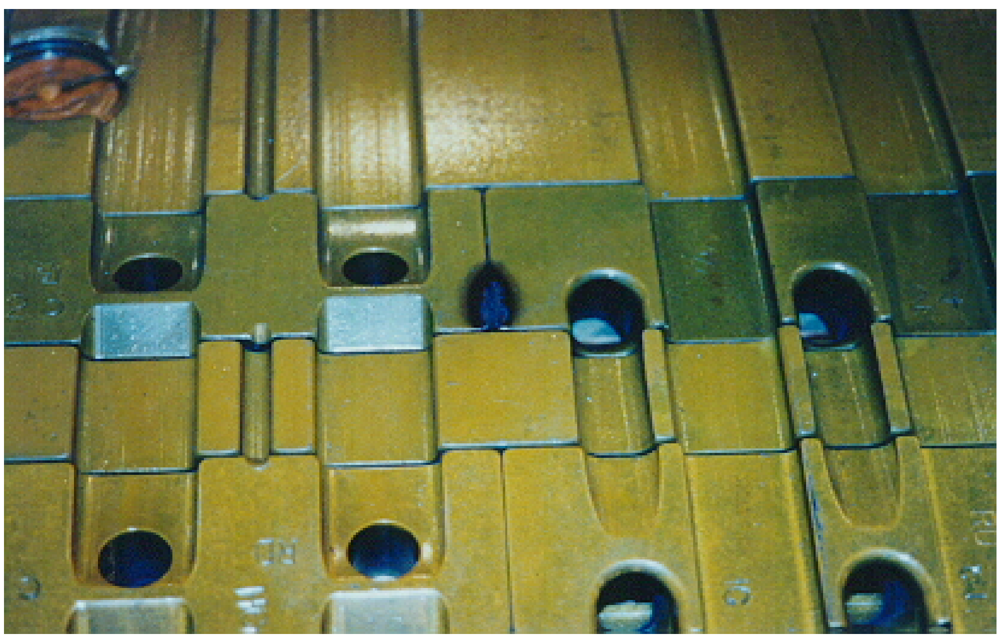


1. Worst case motoring

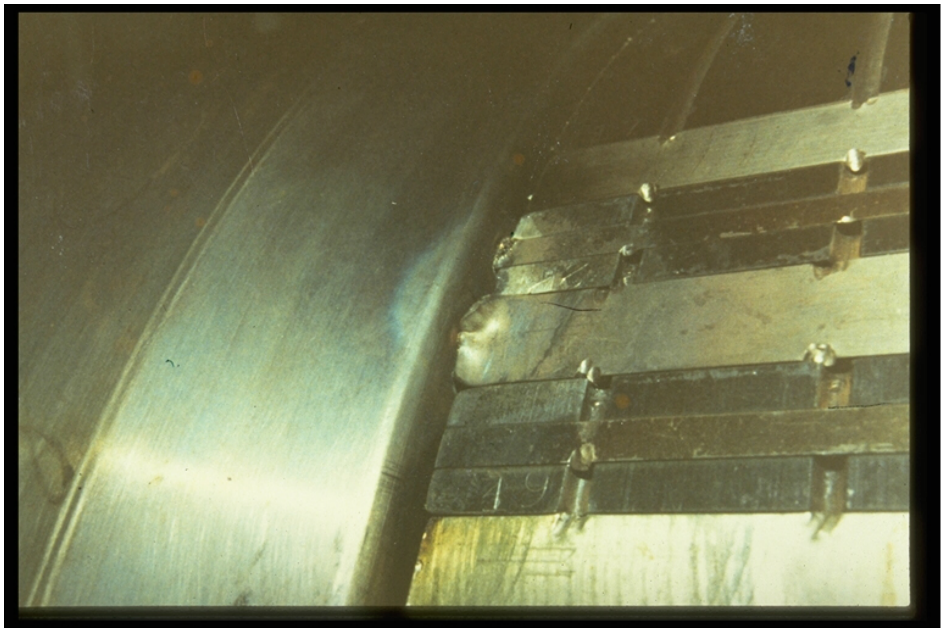
2. Pole forging with cross slots

3. Overheating at cross slot (You can almost see the current flow path)

4. Overheating at cross slot



5. Overheating at wedges



6. Overheating, welding, at the retaining ring

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