GAS TURBINE GENERATOR GOVERNOR SPEED / VOLTAGE CONTROL FOR NON-COMPLEX, ISLANDING OPERATING SYSTEMS – “WHICH CONTROL STRATEGY SHOULD I USE?”

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Roy E. Cossé, Jr. P.E.
Senior Member, IEEE
Chevron U.S.A.
1400 Smith Street
Houston, TX 77002
USA
roy.cosse@chevron.com

Tuyen P. Nguyen, P.E.
Member, IEEE
Chevron U.S.A.
1400 Smith Street
Houston, TX 77002
USA
TPNguyen@chevron.com

Abstract – Papers [1] and [2] focused on governor fundamental speed control basics; the focus of this paper is a fundamental understanding of Automatic Voltage Regulator [3] basics for voltage control and MVAR load sharing. Discussions focus on non-complex, islanding applications for upstream oil and gas and downstream petrochemical facilities, such as, large motor starting, gas turbine step load capability after mechanical tripping of an online generator, load shedding to preserve continued system operation, and electrical protection philosophy basics to maintain system stability.

Index Terms — Isochronous, speed droop, isochronous load sharing, load sharing lines, peer-to-peer, voltage control, power factor control, MVAR control, reactive droop compensation [3], voltage droop, reactive differential compensation [3], cross current compensation, current transformer (CT), automatic voltage regulator (AVR), power management system (PMS), gas turbine generator (GTG), islanding, voltage transformer (VT)

I. INTRODUCTION

This paper builds on two previous papers [1, 2]; [1] provides fundamental discussions and a visual approach of basic isochronous and droop governor speed control, and [2] investigates islanding system turbine governor limitation concerns.

From various discussions with design engineers and operating engineers, fundamental questions about gas turbine speed control and generator voltage control continue to be asked:

- How do GTGs share MW real load and MVAR reactive load?
- Which GTG governor speed control mode should be selected for MW sharing and which AVR control mode should be selected for MVAR sharing?
- What is the largest motor that can be started with GTGs?
- If one GTG suddenly mechanically trips, will the GTGs remain stable?
- Will a 3-phase short-circuit on a feeder cause a plant-wide blackout?

To address these topics, typical upstream oil and gas and downstream petrochemical facilities application examples for non-complex, islanding electrical system examples are reviewed so that engineers have a better understanding of fundamental operating system control philosophies.

II. CONTROL ALGORITHM CLARIFICATION FOR GOVERNOR SPEED CONTROL AND AVR VOLTAGE CONTROL

Because of the proprietary nature of governor speed control algorithms and AVR voltage control algorithms, the following discussions are from an end-user operational perspective, rather than from a detailed analytical, mathematical investigation of a specific control algorithm. This discussion approach is necessary because only the governor and AVR manufacturers can provide detailed application specifics of algorithms, basics, enhancements, options, limitations, etc.

A. Legacy and Modern Governor Hardware/Software Capabilities

Legacy governor systems used analog electronic systems with discrete electronic components to achieve control algorithms; load sharing was achieved by connecting governors via shielded, twisted-pair “load sharing lines” wiring. This type of control strategy is enhanced by modern microprocessor communications or network technology strategies.

Modern governors use microprocessor technology to implement more advanced governor control strategies via hybrid control algorithms previously unavailable with analog methods. Because microprocessors inherently have communication capability, some modern microprocessor governors can communicate by peer-to-peer hard-wiring or via a communications network. This combination of advanced algorithm and communications capabilities with other microprocessor governors provides speed control strategies that were previously not available.

A discussion similar to the above legacy and modern governor control systems can also be stated for AVR voltage control and MVAR sharing.

B. Governor Speed Control Strategies

This paper expects the detailed isochronous and droop discussions of [1] to have been read and a basic understanding of these concepts achieved, so that more advanced governor speed control strategies can be understood. With this as a point of reference, the following lists several typical governor control strategies with a salient point for each. **Since control strategy names, definition and implementation details may vary by manufacturer, application engineers are cautioned to confirm the availability, definition, and implementation specifics of each control strategy.**

Isochronous – maintains constant speed setpoint while MW output varies from no-load to rated load.

Droop – as MW output increases, speed decreases in relation to a preset percent droop setting.

Isochronous Load Sharing – permits multiple GTG governors connected by “load sharing lines” (or via peer-to-peer communications) to proportionally share MW output while maintaining constant speed after a momentary droop for stable operation. The following are two examples of multiple generators operating in isochronous load sharing mode:

1. Twenty-one (21) engines in isochronous load sharing [4] and
2. Five (5) GTGs all in isochronous load sharing (author experience).

Isochronous Load Sharing with a Fixed Bias Speed – permits a GTG connected to an external grid to maintain speed while the GTG output MW varies.

Continuous Rated MW – maintains rated MW output while in droop. (Rated MW output of gas turbines varies depending on ambient temperature.)

Continuous Selectable MW – maintains settable MW output while in droop. This is different from Continuous Rated MW because the MW output may be selected at other than rated MW output.

PMS Speed Adjust – with GTG’s in droop, the power management system adjusts the droop line of each GTG to achieve a preset speed setpoint.

Speed Adjust via Peer-to-Peer Communications – modern, non-PMS governor peer-to-peer communicating method of some governors to reset speed after a droop action of GTGs for increased or decreased MW load.

Although this section indicates different governor control strategies, not all of these strategies apply to non-complex, islanding electrical systems and not all strategies are applied in this paper. A future paper with a complex industrial electrical system example intends to provide application discussions for some, and possibly all, of the remaining listed governor control strategies.

C. AVR Fundamental Voltage Control Strategies

Gas turbine speed control is only one part of the electrical system concern because system-wide voltage regulation is needed to establish and maintain the rotating magnetic field of induction motor loads, a typical primary power consumer in many upstream oil and gas and downstream petrochemical facilities.

When only one islanding generator supplies all in-plant loads, AVR operation is simple; set the AVR for automatic voltage control, provide a voltage setpoint, and the bus voltage is maintained at the voltage setting within the AVR voltage tolerance. However, when two or more generators are connected to a common islanding switchgear bus, a simple voltage control and MVAR load sharing strategy cannot be implemented.

Just as turbine governors have isochronous, droop, and isochronous load sharing speed control algorithms, modern AVRs typically have similar voltage control strategies.

Governor speed droop control is similar to AVR reactive droop compensation [3] (informally referred to as droop). Speed droop reduces speed as MW load is increased; and AVR droop reduces voltage as MVAR load is increased.

Governor isochronous maintains constant speed and is typically implemented when only one GTG is online; this is similar to AVR automatic voltage control which is typically used for one GTG operation.

Governor isochronous MW load sharing mode results in MW load sharing among GTGs and maintains a constant speed after a momentary droop operation. This is similar to AVR reactive differential compensation [4] (informally referred to as cross current compensation), which results in MVAR sharing among GTGs while maintaining a constant voltage.

D. AVR Reactive Droop Compensation (Droop) Basic Concepts [5,6]

Reactive droop compensation (voltage droop) depicted in the Fig. 1 is based on V_{ac} phase-to-phase voltage sensing and I_b phase B current sensing. Reactive droop compensation (droop) is an independent MVAR sharing control strategy that does not require hardware connecting AVRs, connection by peer-to-peer communications, or a network (local, dedicated plant wide, or enterprise wide).

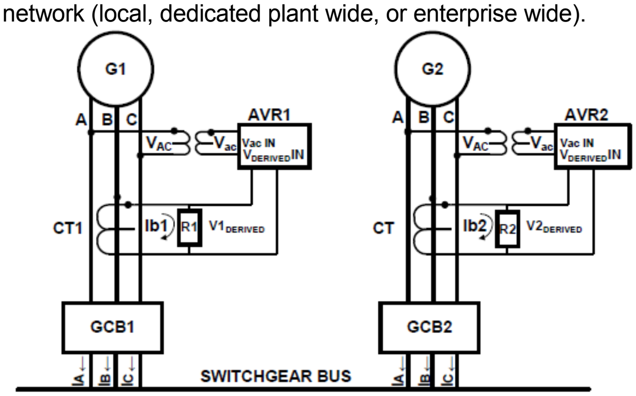

Fig. 1 Example of Conceptual Reactive Droop Compensation (Voltage Droop)

Typically, connection of V_{ac} and I_b are recommended and consistently depicted by AVR manufacturer literature. With legacy AVRs (Fig. 1), sensing V_{ac} is straightforward by connecting to typically provided VTs, but a separate voltage sensing input is used for obtaining voltage data associated with I_b. For I_b to provide a voltage input, a separate CT in phase B and associated secondary circuit external tapped resistor must be added to traditionally provided generator control circuitry. The resistor taps enable AVR manufacturers to offer standard resistor ratings for use with different combinations of CT ratios and droop settings. CT secondary current I_b is circulated through the external secondary resistor to develop a derived voltage $V_{DERIVED}$ ($V1_{DERIVED} = I_{b1}$ x R1) for input into the AVR. **The essence of AVR voltage droop control is the comparison of the angle between V_{ac} and $V_{DERIVED}$ and the resulting magnitude from the vectorial summation of V_{ac} and $V_{DERIVED}$.**

Fig. 2a shows the relationship of V_{ac} and I_b for a generator with A-B-C phase rotation. With a resistive load, the angle between V_{ac} and $V_{DERIVED}$ is 90 degrees and $V_{SUMMATION}$ is nearly the same as the originally sensed V_{ac}; the AVR responds with no change in the AVR output to the generator exciter field because the load has 100% power factor and does not require MVARs.

Fig. 2b depicts an inductive load with I_b lagging V_b. The angle between V_{ac} and $V_{DERIVED}$ is greater than 90 degrees with $V_{DERIVED}$ more in-phase with V_{ac} and $V_{SUMMATION}$ magnitude increases. The resulting AVR action decreases the generator output voltage (droop) proportional to the reactive load magnitude in accordance with the AVR droop setting.

Fig. 2c depicts a capacitive load with I_b leading V_b. The angle between V_{ac} and $V_{DERIVED}$ is less in-phase with V_{ac} and $V_{SUMMATION}$ magnitude decreases. The resulting AVR action is to increase the generator output voltage (droop) proportional to the reactive MVAR load magnitude in accordance with the AVR droop setting. Therefore, the droop curve may have a shape indicated by Fig. 3. A review of a typical generator capability curve shows that the generator cannot accept as many MVARs as the generator can supply.

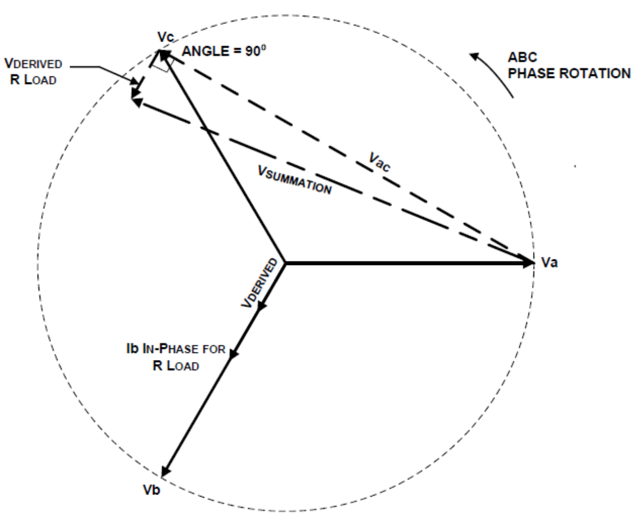

Fig. 2a With a Resistive Load and A-B-C Phase Rotation, Angle between V_{ac} and $V_{DERIVED}$ is 90°

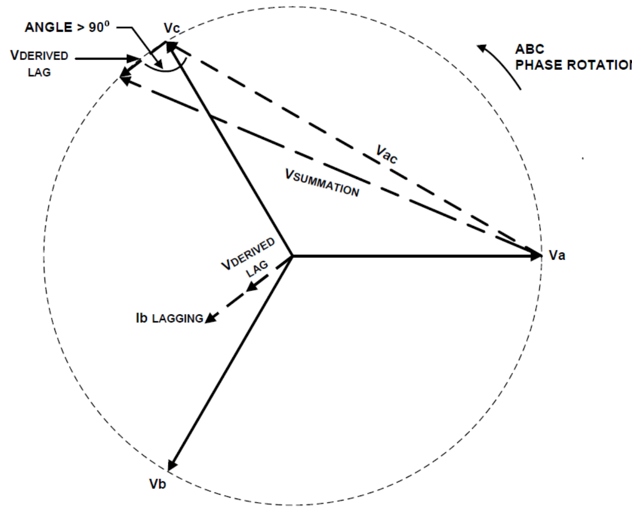

Fig. 2b With a Lagging Inductive Load and A-B-C Phase Rotation, Angle between V_{ac} and $V_{DERIVED}$ is greater than 90° ($V_{DERIVED}$ More In-Phase)

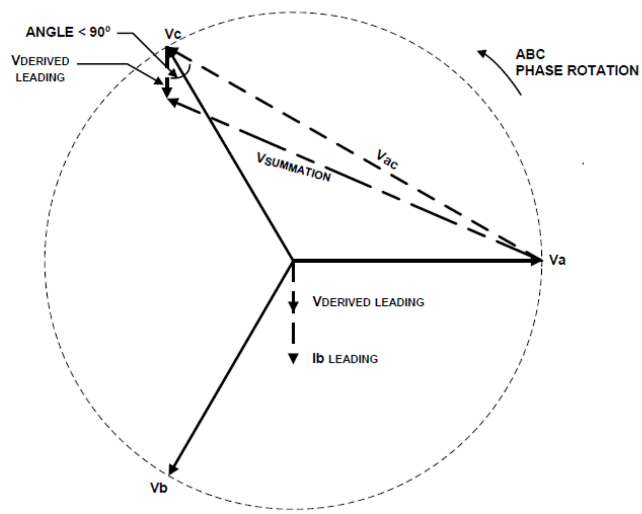

Fig. 2c With a Leading Capacitive Load and A-B-C Phase Rotation, Angle between V_{ac} and $V_{DERIVED}$ is greater than 90° ($V_{DERIVED}$ Less In-Phase)

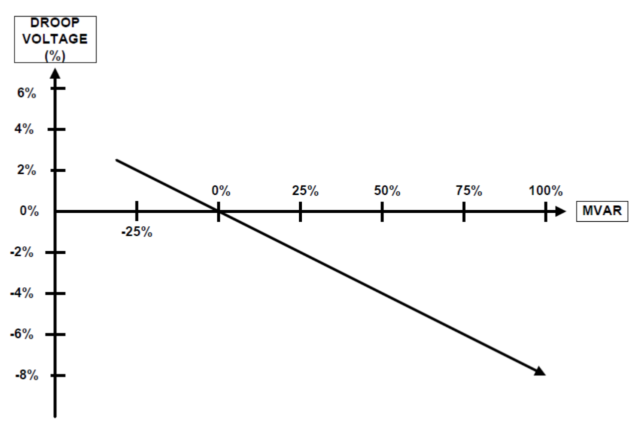

Fig. 3 Example of AVR Droop Curve

Figs. 4a, 4b, and 4c graphically summarize the resistive, inductive, and capacitive load concepts of V_{ac} compared to $V_{DERIVED}$ discussed in this section.

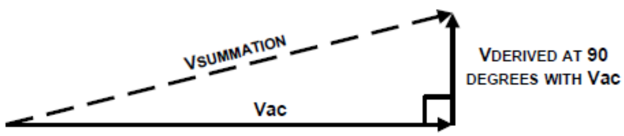

Fig. 4a V_{ac} compared to $V_{DERIVED}$ with a Resistive Load

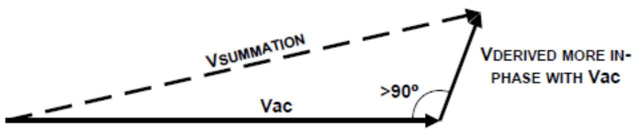

Fig. 4b V_{ac} compared to $V_{DERIVED}$ with an Inductive Load

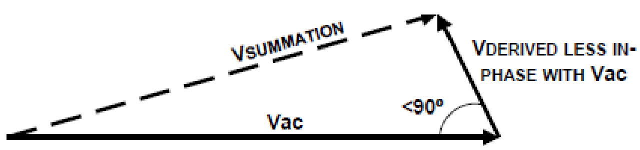

Fig. 4c V_{ac} compared to $V_{DERIVED}$ with a Capacitive Load

Reactive droop compensation (droop) is an independent MVAR sharing control strategy that does not maintain generator output voltage; generator output voltage decreases for reactive loads and increases for capacitive loads.

Modern AVR hardware enables AVR manufacturers to continue the evolution of AVR technology with improvements and innovations to algorithms, software, networking, etc. Modern AVR design may only require V_{ac} and a direct I_b input (no external resistor) for use with more complex mathematical algorithms; and with modern communications networks, cable impedance distance limitations between AVRs may no longer be a concern. Unfortunately, AVRs may not be wired as recommended by manufacturer's typical instruction manual literature with V_{ac} and $V_{DERIVED}$ input into the AVR. Instead, the following may be input into the AVR:

1. V_{ca} instead of V_{ac},
2. B phase CT polarity may be reversed with the non-polarity marking input to the AVR polarity input, or
3. The phase rotation input into the AVR may be A-C-B, instead of A-B-C.

So, what is the methodology to determine the adequacy of non-typical or non-depicted input configurations? **For correct wiring connection and phase rotation, manufacturers' literature should be confirmed.** Typically, when Droop and Cross Current Compensation configurations are applied with A-C-B phase rotation and the voltage sensing input connection of V_{ac} is input into the AVR, i.e., the same as with A-B-C rotation, then, the CT polarity input must be swapped so that the $V_{DERIVED}$ is more in-phase with Vac. **This must be confirmed with the manufacturer's published literature so that a correct application is achieved. If there is any doubt about the application, contact the manufacturer for confirmation of the system wiring configuration and AVR settings.**

E. AVR Reactive Differential Compensation (Cross Current Compensation) Basic Concepts [5,6]

As discussed, reactive droop compensation provides an independent MVAR sharing method, but voltage droops as MVAR loading increases. However, for a typical industrial application with a significant induction motor load, a drooping generator voltage may not be acceptable to electrical system operation. If the system at no-load has 100% voltage, then at full load the system voltage may droop 5% or 6% to 95% or 94% voltage, an unacceptable operating voltage on the main distribution switchgear bus. If 100% voltage is desired at full load, then at no-load a 105% or 106% voltage would be required. An alternative approach would include PMS intervention to control main distribution switchgear bus voltage within acceptable voltage limits.

Fig. 5a depicts reactive differential compensation (cross current compensation) in an interrelated configuration that "cross connects" online generator CTs so that MVAR sharing occurs **without** a decrease in generator output voltage. Stated differently, cross current compensation maintains generator output voltage while MVAR load is shared between generators. Generator auxiliary contacts 52bCCC are necessary so that an offline generator does affect the VAR sharing of the online generator(s). When a generator is offline and the circuit breaker is open, normally closed breaker auxiliary contacts are closed. Fig. 5b provides more details of the CT secondary current circuit. For correct application, AVR distance limits or wiring conductor sizing requirements must be confirmed with the AVR manufacturer. When there are long distances between AVRs and external burden resistors, cross current compensation interconnecting wire size may become significant compared to traditional control circuit wire size.

To illustrate the concepts of cross current compensation, Fig. 5c example shows a cross current compensation configuration with two identical generators. An example 200A reactive current is assumed produced by each generator. Since the external burden resistors of this example are assumed to be identical 1 Ohm and the AVRs are identical, CT1 secondary current I_{b1} "out of the dot" splits with I_{b11} = 1A into R1(+) and I_{b12} = 1A into R2(-). Likewise, CT2 secondary current I_{b2} splits with I_{b21} = 1A into R2(+) and I_{b22} = 1A into R1(-). Because the currents flowing into R1 are equal in magnitude and opposite in direction, the derived voltage $V1_{DERIVED}$ across R1 is equal to zero. A similar discussion applies to the derived voltage $V2_{DERIVED}$ across R2, which is also zero. Because the voltage across R1 is zero, AVR1 maintains a constant generator G1 output voltage; similarly, the voltage across R2 is zero, and AVR2 maintains a constant generator G2 output voltage.

However, as shown in Fig. 5d, if AVR1 begins producing more MVARs than AVR2, there will be a circulating current between R1 and R2. The polarity of the voltage drop across R1 will appear to AVR1 as a greater inductive load, and AVR1 should respond by decreasing generator G1 output voltage. Whereas, the voltage drop across R2 will appear to AVR2 as a greater capacitive load, and AVR2 should respond by increasing generator G2 output voltage. This cross current "give and take" strategy yields a shared MVAR output while maintaining generator output voltage without droop.

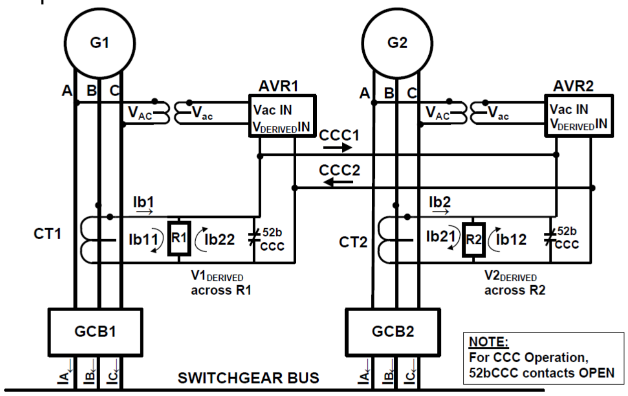

Fig. 5a Example of Conceptual Reactive Differential Current Compensation (Cross Current Compensation)

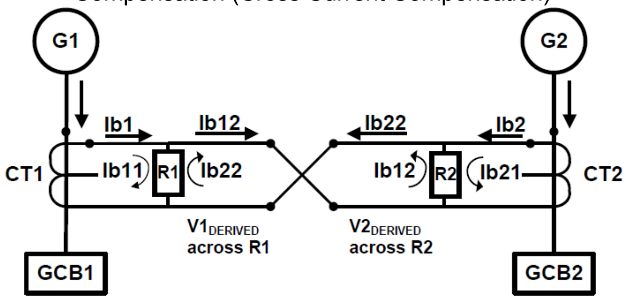

Fig. 5b Secondary Circuit Simplification for Example of Conceptual Reactive Differential Current Compensation (Cross Current Compensation)

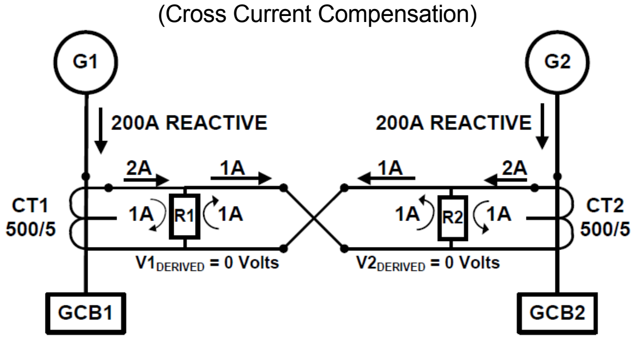

Fig. 5c Example Illustration of Cross Current Compensation with Generator Equal MVAR Sharing

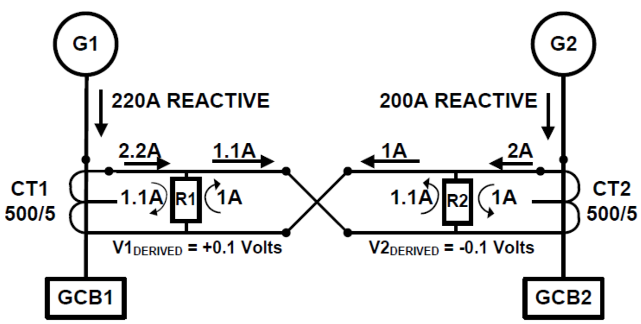

Fig. 5d Example Illustration of Cross Current Compensation with Generator Unequal MVAR Sharing

The discussions of this section are about AVR fundamentals and that the specific user applications and project computations must be confirmed with the manufacturer's published instruction manual, recommended application instructions, and manufacturer application engineer feedback.

F. AVR - Voltage Control Strategies

The following lists several AVR voltage control strategies and a salient point for each.

Automatic Voltage Control – applicable with one GTG online to control generator output voltage or (bus voltage).

Reactive droop compensation (Droop) – (Fig. 1) provides stable system operation with multiple online GTGs by independent voltage droop relative to GTG MVAR loading.

Reactive differential compensation (Cross Current Compensation) – (Fig. 5a), a proportional MVAR sharing method for bus connected GTGs with sharing based on MVAR loading without an increase or decrease of output voltage. When GTGs are connected to different buses, confirm the application with the manufacturer.

Voltage Droop with PMS Voltage Adjust – when multiple GTGs are not all bus connected on the same bus, droop permits stable operation for a "host controller" to maintain voltage within a predetermined voltage regulation "window".

Power Factor Control [3] (Constant Power Factor) – a typical application when an in-plant GTG is connected to a utility; constant power factor is maintained based on the in-plant GTG MW loading.

VAR Control [3] (Constant MVAR) – similar to Constant Power Factor except a fixed MVAR magnitude is provided by the generator regardless of the turbine MW power output.

Although this section indicates different AVR control strategies, not all of these strategies apply to non-complex, islanding electrical systems and are not discussed in this paper. A future paper intends to include an example of complex industrial systems with a utility connection where the remaining listed AVR control strategies are discussed.

III. SYSTEM EXAMPLES WITH GOVERNOR/AUTOMATIC VOLTAGE REGULATOR APPLICATION

Fig. 6 is considered a typical non-complex, islanding industrial electrical system example that illustrates some of the control strategies discussed above. The four GTGs are direct connected to a common power distribution switchgear bus. The GTGs are from the same manufacturer and have identically rated MW, frequency, phases, and power factor with governors capable of isochronous load sharing via load sharing lines and AVRs connected in cross current compensation mode.

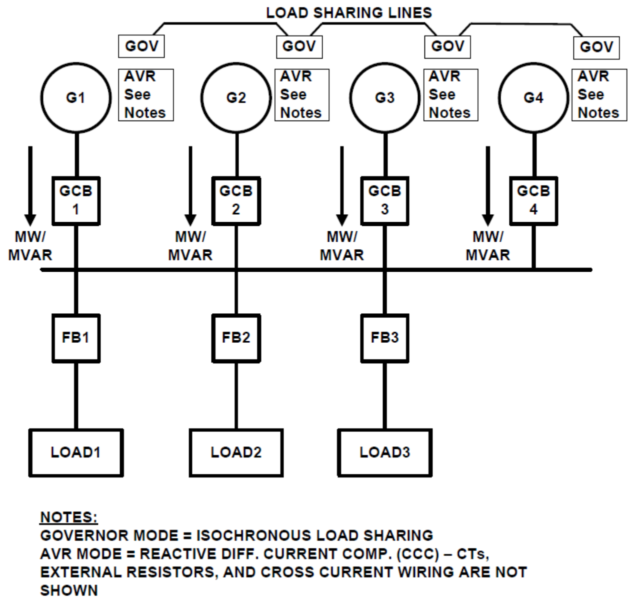

Fig. 6 Four GTG Non-complex Islanding System for Large Motor Starting and Step Load Example

When discussing online load and online GTG MW capability, the terms N, N+1, N+2, etc. are commonly used. N, N+1, and N+2 relate to the normal operating MW, MVAR load demand compared to MW, MVAR generation, prior to a mechanical turbine trip or a severe, three-phase electrical short-circuit that significantly depresses facility-wide main electrical distribution buses. As an example, an N+1 operating condition is understood to have one more online GTG than the load requires; but, if a GTG should trip, the remaining online "N" GTGs should be capable of powering the normal operating MW, MVAR load, provided the GTG step load capability is not exceeded.

If only one online GTG powers a load, the governor can be set in isochronous mode (with the load sharing lines shorted) to maintain constant speed (frequency) as MW load increases or decreases, and the AVR can be set in automatic voltage control mode (with 52bCCC shorted) to maintain constant bus voltage as MVAR load increases or decreases.

When two or more generators are online, the governor and AVR control strategies must be changed from a one GTG configuration. Because of the load sharing lines, the governors can be operated in Isochronous Load Sharing mode to share MW while maintaining a constant speed reference, and the AVRs with cross current compensation interconnection wiring can be set for CROSS CURRENT COMPENSATION mode to share MVARs while maintaining a constant generator output voltage. Of course, a droop strategy could be selected for both the governor and AVR; but, this would result in a speed decrease as MW load is increased and a voltage decrease as lagging MVAR load is increased. To achieve better speed and voltage regulation when a droop strategy is implemented for both the governor and AVR, operator intervention or a PMS host would be needed. However, if one GTG governor is set for isochronous and the other GTG governors are set for droop, then the isochronous GTG will accept the load until the droop lines of the other GTGs governors are shifted upward by operator or PMS intervention so that the non-isochronous GTGs can accept load [1]. The AVR of the isochronous governor GTG would have to operate in droop while the droop governor GTGs could operate in either droop or cross current compensation.

One philosophical opinion for non-complex, islanding electrical systems is to maintain a fundamental and secure control strategy using GTG manufacturer recommended, provided, and warrantied equipment. As an example, system GTGs in Fig. 6 are the same type/model, built by the same manufacturer, direct connected to the same switchgear bus, installed at the same time, and have the same speed control and excitation control systems. For this application, the first considered governor control strategy should be isochronous load sharing for constant speed regulation and MW sharing; and the first considered AVR control strategy should be cross current compensation for MVAR sharing while maintaining a constant voltage.

The reason for this approach is that the governor and voltage regulator control algorithms have been developed by manufacturers from a number of years of refinement from laboratory investigations, computations, and trial-and-error testing and feedback from field installed operations. One author considers the manufacturers standard control algorithms to be more operationally secure than a separate external host controller for speed and voltage control because the GTG manufacturer has a more intimate knowledge of the design, factory and field operating performance details of the GTG. For the Fig. 6 example system, a high-level PMS communicating host controller can always be implemented for refined adjustment of controlling turbine speed and generator voltage; however, this adds additional complexity because the host controller acts after the governor and AVR algorithms have operated.

The following are other governor and AVR control and protection considerations.

A. *Step Load Capability*

Knowing how an electrical power system is going to perform during typical transient conditions is a big concern of plant operations. Although there may be other scenarios, there are three typical fundamental transient operating considerations that require industrial electrical application engineers to investigate GTG step load capability, i.e.,

- Large motor starting,
- Turbine mechanical trip, and
- Electrical three-phase short-circuit on the generator cable or within the generator.

For many industrial oil and gas land or marine facilities, there are typically two types of step load concerns during large motor starting:

1. When only one GTG starts a large motor with across-the-line start, and
2. When several online GTGs start a large motor across-the-line.

During start-up, after a facility scheduled shutdown or unscheduled facility outage, plant load is gradually increased and GTGs are started only as needed to support the load at that time; the GTGs are not all started at the same time with minimal plant loading. Sometimes, during plant start-up, an operating condition requires starting a large motor with only one GTG online; this condition occurs frequently during commissioning and initial construction start-up when the contractor needs to start the largest medium-voltage motor with very minimal load. This type of operating condition requires previous investigation to confirm that the motor can be started with only one online GTG. If previous calculations confirm that more than one GTG is required, then additional GTGs must be placed online, even if the steady-state loading does not demand more than one online GTG. The authors are familiar with a facility that has four identical bus-connected GTGs. Only two online GTGs are needed for the maximum steady-state operating load (N), but three GTGs are needed during large motor starting (N+1). However, to guarantee the availability of three GTGs for large motor starting, a fourth GTG (N+2) is necessary because during periods of GTG maintenance or repair only three GTGs would be available. Although starting a large motor requires investigation of turbine step load capability, the greater concern is the system voltage drop incurred on the electrical system caused by the starting motor inductive loading, a significant MVAR starting requirement.

A sudden, unexpected turbine trip causes significant MW and MVAR step load demands on the remaining online GTGs. Since step load capability varies by GTG manufacturer turbine class and design, step load capability must be confirmed with the GTG manufacturer for each specific application. (Step load performance of single-shaft, two-shaft, and hybrid shaft GTGs is acknowledged as an important topic, but because of paper length constraints these discussions are deferred to a future paper on complex industrial systems.) After an unexpected turbine trip, not only is a significant MW step load requirement demand imposed on the remaining online turbines; but a significant MVAR demand is imposed on the generators; and the generator capability curve must be reviewed to confirm that generator MW and MVAR demands are within the limits of the generator capability curve. If the remaining online GTGs cannot support the needed MW and MVAR requirements, load shedding is required. Consequently, confirming turbine step load capability cannot be limited only to turbine speed recovery, but must also include voltage regulator response for determining complete electrical system performance. Electrical power system transient stability calculations must be performed to predict system operation during and after step load conditions by determining if fast load shedding is needed; and, if required, the loads that must be shed for system recovery and continuous stable operation.

A three-phase electrical short-circuit on a generator cable or within a generator is a very onerous condition because not only is there a loss of MWs and MVARs from one GTG, but the system voltage is significantly depressed by the three-phase short-circuit condition. This means that the remaining online generators must not only provide steady-state MWs and MVARs from the loss of one GTG, but the generators must also provide additional MVAR support for the plant induction motor loads to re-establish the internal back electro-motive force. During severe system voltage depression caused by a three-phase short-circuit the motor internal voltage discharges into the short-circuit based on the generator internal, pre-fault voltage and impedance and external impedances. Again, transient stability calculations must be performed to confirm load shedding requirements and determine the load shedding philosophy.

B. Fast Load Shedding

With islanding electrical power generating systems, maintaining stability is paramount for facilities on land or water. No one likes to be on a ship or offshore facility and the lights “go off”. So when an online GTG unexpectedly trips offline, it is important to have previously determined if the remaining online GTGs can accommodate the additional MW step load increase or if a fast load shedding system must operate to achieve a proper balance between online MW, MVAR generation and the MW, MVAR load demand.

Legacy load shedding systems were based on generator circuit breaker trip and frequency and were implemented in either a separate, stand-alone, discrete device system or a programmable logic controller type system. Modern microprocessor based fast load shedding systems are also preferred as a separate, stand-alone system, rather than part of a facility-wide power management system.

“How many milliseconds does the system have to recover before load shedding is needed to mitigate a plant-wide outage?” is an “age-old” question; and the answer, of course, is “It depends”. For a typical industrial system, 200ms to 250ms has traditionally been used as a “rule of thumb” for an acceptable electrical power system recovery range before load shedding is required. However, this was in a legacy era when underfrequency based load shedding systems were implemented because analog protection and control technology were available at the time. Microprocessor based equipment was not readily available for electrical power system use and was not the practice of industrial electrical power system engineers, although microprocessor control became available in the late 1970’s via slow responding programmable control logic (PLC) equipment. Today, modern, fast acting protection and control equipment with communications capabilities may achieve sensing, recognition, and response times without circuit breaker tripping time of 80ms or less, enabling less than 200ms total system operation to be achieved with ample time margin. Since the above load shedding discussions are “rule of thumb” comments about equipment response and system recovery time, practicing application engineers must confirm the specific facility operating conditions and the specific equipment proposed for use or previously implemented.

There are many well-written papers that describe load shedding theory, implementation, and practice. These papers should be reviewed and well-understood by practicing engineers so that the most recent developments, practices, and equipment applications are utilized.

C. Protective Device Operation and System Stability

Although the above discussions are concerned with the operating conditions of large motor starting, turbine mechanical trip, GTG step load capability, and fast load shedding, these are not the only transient considerations requiring review. Islanding electrical power systems demand continuous power operations for personnel safety, safe process control, and stable electrical system operation. To achieve these goals during and after three-phase short-circuit conditions, the fault must be isolated and removed from service as fast as possible.

When a three-phase fault occurs on a main generator feeder cable or generator winding of Fig. 7, an onerous transient condition occurs because not only is the main electrical distribution system voltage significantly depressed but there is one less GTG to produce MWs and MVARs. Achieving fast fault isolation is paramount for a generator cable or generator fault and is achieved by generator 87 phase differential protection. Modern protection relays designed specifically for generator, bus, and transformer protection typically include fast acting 87 differential phase protection; whereas, modern feeder protection relays have 50 instantaneous overcurrent protection, that is typically slower responding than 87 differential protection. Because low-ratio current transformers (CT's) are typically implemented on industrial plant feeders, the speed of feeder microprocessor-based protection 50 elements is typically delayed because of CT saturation conditions and the type of internal protection relay algorithm(s) that are provided [7, 8, 9]. The speed of response of feeder protection 50 instantaneous protection must be thoroughly investigated and included in protection relay timing margins and transient stability protection relay/circuit breaker system tripping times.

A fundamental electrical protection practice is to provide fast fault detection and isolation by differential and instantaneous protection methods; this should be done as much as practical.

Fig. 7 example electrical system is provided to illustrate some protection relay concerns during three-phase fault conditions on select buses.

- For three-phase fault "FAULT G3" on generator G3 cable or within the G3 generator, phase differential 87G element of modern microprocessor generator protection relay 87G3 provides detection and fast operation for isolation by circuit breaker GCB3.
- For three-phase fault "FAULT B1"on 13.8kV main switchgear bus, 87B bus differential protection on relay 87BTquickly detects faults for fast tripping and isolation by all circuit breakers connected to the 13.8kV Main Switchgear Bus.
- For three-phase fault "FAULT F1"on Feeder Cable F1, the 50 instantaneous element of feeder breaker FB1 protection relay detects the fault and causes feeder circuit breaker FB1 to trip and isolate the feeder fault.
- Additional complexity is introduced by 13.8kV feeder breaker FB2 powering a remote switchgear of the same voltage rating. This condition may occur on a ship where Topsides switchgear powers hull switchgear; or a process plant where 13.8kV main distribution switchgear powers downstream 13.8kV remote switchgear. These system configurations add additional complexity because protection selectivity and fault isolation considerations between the upstream feeder breaker FB2 and the downstream 13.8kV switchgear do not permit 50 instantaneous protection on feeder FB2 circuit breaker. With a traditional time delay of 200ms to 250ms for each 51 protection relay, system stability limits of 200ms to 250ms are typically compromised.
- For a fault on Feeder Cable F2, the 51 relay on circuit breaker FB2 could have a time delay setting of 400ms to 500ms or greater depending on the relay protection settings of the remote 13.8kV switchgear. Hence, providing additional protection, such as, line current differential protection 87L to Feeder Cable F2 should be considered, as well as, other modern protection alternatives. Of course, transient stability calculations are necessary to confirm complete system operational requirements and limits.

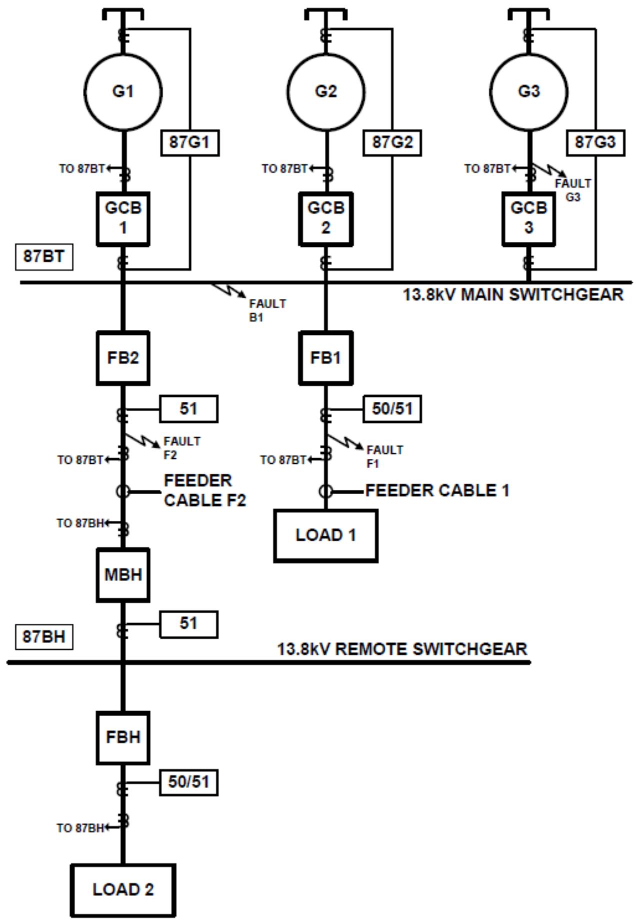

Fig.7 – Example System with Differential, Instantaneous, and Overcurrent Phase Protection

Fig. 7 Example System with Differential, Instantaneous, and Overcurrent Phase Protection

IV. SUMMARY

Discussions included GTG control strategies for governors and AVRs for typically encountered, non-complex islanding generator system for upstream oil and gas and downstream petrochemical facilities. In-depth AVR fundamentals discussions provide increased understanding of AVR application strategies for use with non-complex applications. Large motor starting, step load capability during mechanical tripping of an online generator, electrical short-circuit, load shedding to preserve continued system operation, and electrical protection philosophy basics to maintain system stability were reviewed. With this information and [1] and [2], application engineers should have a good, basic understanding of governor and AVR fundamentals for application to non-complex electrical system configurations and a good background for more complex system configurations.

V. CONCLUSION

Since this paper is limited to non-complex, islanding industrial electrical systems, only some of the governor speed and AVR voltage control strategies can be discussed with application specific reference. To discuss the remaining governor speed and AVR voltage control strategies, a future paper with complex electrical system configurations, including a utility connection, is proposed.

VI. REFERENCES

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I. VITAE

Roy E. Cossé, Jr. (BSEE1968/MSEE1972), forty-five years Electrical Engineering application experience in upstream, downstream, offshore, and petrochemical industries. Experiences encompass conceptual design, detailed engineering, training, startup, maintenance and operations with power system analysis specialty. A professional engineer registered in Texas (inactive) and Louisiana. Since 1995, founder/presenter of IEEE Houston Continuing Education seminars. Co-authored and presented IEEE PCIC and Pulp and Paper conference technical papers/tutorials. Mr. Cossé is a Chevron Senior Staff Electrical Engineer.

Tuyen P. Nguyen, P.E., received his BSEE (summa cum laude) in 2004 and Master of Electrical Engineering degree in 2008, both from the University of Houston. Upon receiving his bachelor’s degree, he worked as an electrical engineer for WorleyParsons, where he supported large petrochemical projects in the Middle East. In 2007, Tuyen joined Chevron Energy Technology Company’s electrical power systems group. His technical responsibilities include electrical power generation, distribution, protective relaying, power system studies, and capital projects. He is a registered professional engineer in the state of Texas.