12 Power System Controls

ISO New England's state-of-the-art control center helps to ensure the reliable operation of New England's bulk power generation and transmission system (Photograph © Adam Laipson)

Automatic control systems are used extensively in power systems. Local controls are employed at turbine-generator units and at selected voltage-controlled buses. Central controls are employed at area control centers.

Figure 12.1 shows two basic controls of a steam turbine-generator: the voltage regulator and turbine-governor. The voltage regulator adjusts the power output of the generator exciter in order to control the magnitude of generator terminal voltage V_t. When a reference voltage V_{ref} is raised (or lowered), the output voltage V_r of the

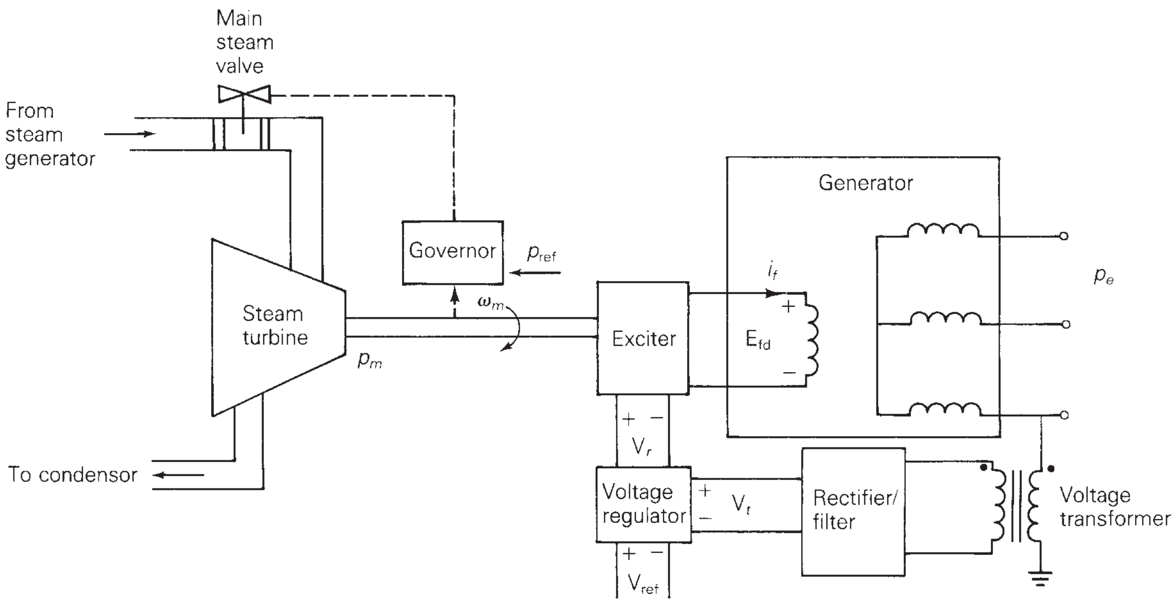

FIGURE 12.1

Voltage regulator and turbine-governor controls for a steam-turbine generator

regulator increases (or decreases) the exciter voltage E_{fd} applied to the generator field winding, which in turn acts to increase (or decrease) V_t. Also a voltage transformer and rectifier monitor V_t, which is used as a feedback signal in the voltage regulator. If V_t, decreases, the voltage regulator increases V_r to increase E_{fd}, which in turn acts to increase V_t.

The turbine-governor shown in Figure 12.1 adjusts the steam valve position to control the mechanical power output p_m of the turbine. When a reference power level p_{ref} is raised (or lowered), the governor moves the steam valve in the open (or close) direction to increase (or decrease) p_m. The governor also monitors rotor speed ω_m, which is used as a feedback signal to control the balance between p_m and the electrical power output p_e of the generator. Neglecting losses, if p_m is greater than p_e, ω_m increases, the governor moves the steam valve in the close direction to reduce p_m. Similarly, if p_m is less than p_e, ω_m decreases, the governor moves the valve in the open direction.

In addition to voltage regulators at generator buses, equipment is used to control voltage magnitudes at other selected buses. Tap-changing transformers, switched capacitor banks, and static var systems can be automatically regulated for rapid voltage control.

Central controls also play an important role in modern power systems. Today's systems are composed of interconnected areas, where each area has its own control

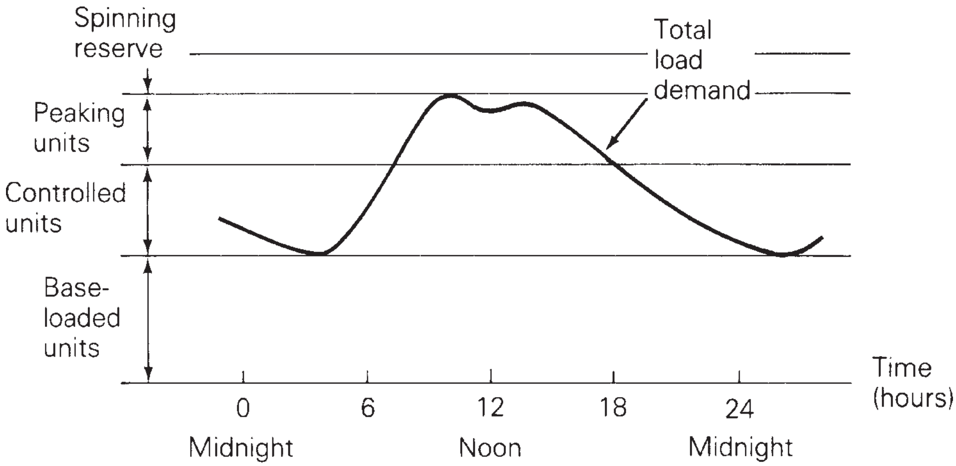

FIGURE 12.2

Daily load cycle

center. There are many advantages to interconnections. For example, interconnected areas can share their reserve power to handle anticipated load peaks and unanticipated generator outages. Interconnected areas can also tolerate larger load changes with smaller frequency deviations than an isolated area.

Figure 12.2 shows how a typical area meets its daily load cycle. The base load is carried by base-loaded generators running at 100% of their rating for 24 hours. Nuclear units and large fossil-fuel units are typically base-loaded. The variable part of the load is carried by units that are controlled from the central control center. Medium-sized fossil-fuel units and hydro units are used for control. During peak load hours, smaller, less efficient units such as gas-turbine or diesel-generating units are employed. Renewable generators, such as wind and solar, are usually operated to maximize their outputs for the given wind or solar conditions since their "fuel" is essentially free. In addition, generators operating at partial output (with *spinning reserve*) and standby generators provide a reserve margin.

The central control center monitors information including area frequency, generating unit outputs, and tie-line power flows to interconnected areas. This information is used by automatic *load-frequency control* (LFC) in order to maintain area frequency at its scheduled value (60 Hz) and net tie-line power flow out of the area at its scheduled value. Raise and lower reference power signals are dispatched to the turbine-governors of controlled units.

This chapter covers automatic controls employed in power systems under normal operation. Sections 12.1 and 12.2 describe the operation of the two generator controls: voltage regulator and turbine-governor, and load-frequency control is discussed in Section 12.3.

CASE STUDY

Beginning at 4:10 p.m Eastern Daylight Time on August 14, 2003, an enormous power disruption resulted in the loss of power to approximately 50 million people across the eastern Great Lakes region, the northeastern United States, and parts of eastern Canada. It took more than 24 hours to restore substantial load. The following article provides a restoration summary and reviews the challenges that had to be overcome to restore power [15]. A general pattern for sound restoration is inferred from the restoration process.

No Light in August: Power System Restoration Following the 2003 North American Blackout

E.H. Allen, R.B. Stuart, and T.E. Wiedman

On 14 August 2003, three 345-kV transmission circuits in northeastern Ohio contacted overgrown trees during a 40-minute time span, starting a chain of events that culminated in the collapse of the electrical grid across the eastern Great Lakes region, the northeastern United States, and parts of eastern Canada. In the aftermath of the disturbance, large portions of the Eastern Interconnection were blacked out, and several electrical islands were present. System operators faced a formidable task: to reassemble the grid and restore power to tens of millions of customers. The challenges that had to be overcome varied significantly from one state or province to another. New York, New England, Ontario, Michigan, and Ohio each had unique problems that operators had to address.

New York

Faced with a system restoration task, the priorities of the New York Independent System Operator (NYISO) restoration plan were to: (1) stabilize the remaining system, (2) extend the stabilized system into blacked-out areas for generation and load restoration, (3) connect energized islands to the stabilized system for restoration of frequency and voltage control, and (4) restore normal transmission operations. In keeping with the restoration plan, the highest priority operations were to: (1) energize the New York state power system, (2) synchronize the New York state power system with the Eastern Interconnection, and (3) restore off-site power to nuclear plants in New York. The operators first had to assess the state of the system and determine what was still energized. They found that New York had split electrically into two pieces, with the southeast part of the state blacked out and upstate New York remaining as an electrical island but with greatly reduced load and generation. Of the 28,700 MW of load in the New York control area just prior to the disturbance, only 5700 MW remained. Figure 1 is a representation of the New York power system in the following sequence of events.

An early step taken was the initiation of black-start procedures at the Gilboa pumped-storage plant in east-central New York (Figure 1). Two Gilboa units (250 MW each) were started at 4:27 p.m., but they could not be synchronized to the remaining power system until after 7:05 p.m. (when the Marcy–New Scotland 345-kV line was reclosed) due to excessive voltage disparity between the Gilboa and Fraser substations. Long Island Power Authority (LIPA) began restoring the Long Island system independently of NYISO, using gas turbines to energize the local system and pick up load.

After finding that the remaining system was an island, operators

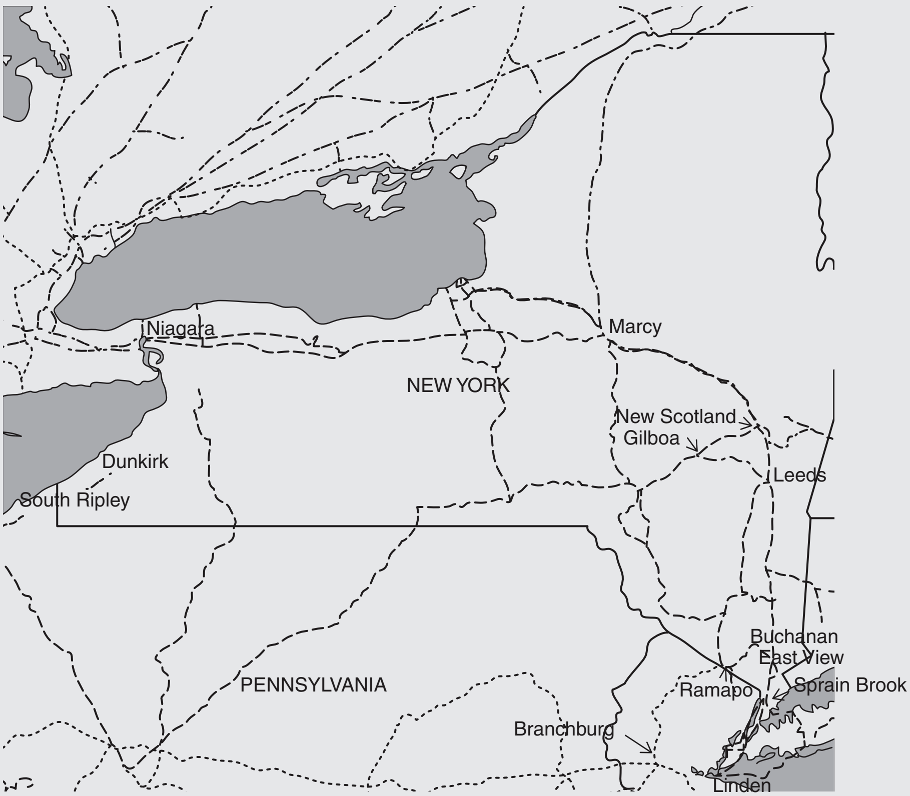

Figure 1 A representation of the New York Power System (green lines indicate 765 kV, orange lines indicate 500 kV, and red lines indicate 345 kV)

concluded that in order to restore transmission circuits, they would need to restore load at the same time so as to prevent excessively high voltage. In order to restore load, however, they would need additional generation to serve the additional load and keep frequency under control. In order to bring generation online, the voltage and frequency in the New York island would need to be stable. Resynchronization of the island to the Eastern Interconnection therefore became the top priority for NYISO operators in order to achieve the restoration goals.

An initial attempt to synchronize the upstate New York island to the Eastern Interconnection at 6:02 p.m. by closing the Branchburg-Ramapo 500-kV circuit failed because the frequency difference between the two systems was too large. Interestingly, the synchronization was actually achieved without operators' knowledge at 6:52 p.m., as an automatic reclosing scheme on the South Ripley–Dunkirk 230-kV line at the far western end of the island detected that the two systems had come close enough in phase angle and voltage to permit a reclosing attempt, and the reclosing attempt was successful. When operators again attempted to reclose the Branchburg-Ramapo 500-kV circuit at 7:06 p.m., it was thus discovered that the two systems were already synchronized. The Branchburg-Ramapo 500-kV circuit was then successfully reclosed, providing a second, stronger transmission path for synchronizing the upstate New York island and stabilizing the frequency of the energized portion of the New York transmission system.

After resynchronization with the Eastern Interconnection was achieved, the energized system was extended into the New York City metropolitan area by a progressive reenergization of the 345-kV network from north to south. The Sprain Brook substation in Westchester County was energized at 7:56 p.m. from Ramapo via the Buchanan and Eastview stations. By 9:50 p.m., a second 345-kV transmission path from New Scotland down the east side of the Hudson River through Leeds to Sprain Brook had been restored, although the two transmission paths were not connected at Sprain Brook until 12:08 a.m. on August 15. A transmission path from New Jersey into Brooklyn and Staten Island was energized at 11:00 p.m.; this path also provided a connection for East Coast Power's Linden plant. A 345-kV path from Sprain Brook into the West 13th Street station in Manhattan was energized at 4:08 a.m. The LIPA system, which had been restored independently of NYISO, was synchronized with the rest of New York and the Eastern Interconnection at 5:12 a.m.

New England was resynchronized with New York and the Eastern Interconnection at 1:53 a.m. This resynchronization could not be accomplished until after the paralleling operation at Sprain Brook was completed to stabilize the voltage in eastern New York. New England provided substantial emergency power (up to 600 MW) throughout the remainder of the restoration. Restoration of generation, load, and additional transmission continued throughout the evening of August 15. By order of the U.S. Department of Energy, the Cross-Sound Cable was energized at 12:26 p.m., carrying 100 MW of emergency flow. This dc link between Connecticut and Long Island had been constructed but had not yet been authorized to begin operation.

By 12 a.m. on August 15, 40% of New York load had been restored, and 60% of the New York load was restored by 4 a.m. on that day. Because the morning load pickup exceeded the capability of the partially restored system, the Emergency Demand Response Program, which calls for voluntary load reduction, was invoked at 8:59 a.m. When this action proved insufficient, 300 MW of load west of Utica was shed at 9:33 a.m. Area control error at the time was –630 MW. Half of this load was restored at 10:02 a.m., and the rest was restored at 10:24 a.m. By 10:30 p.m. on August 15, 100% of New York load had been restored.

NYISO found that several lessons were learned from the experience:

- Staff duties in the event of such a calamity needed to be clearly defined.
- Communications needed to be improved.
- A recommendation was made to investigate a formal process for distributing information to transmission and generator owners.
- It was concluded that restoration training should be expanded.

New England

New England and the Maritimes remained intact, as a single island. The aggregate flow across the ac ties (i.e., excluding dc imports) was very small before the event, and the total generation loss and load loss during the event in these areas were nearly identical (around 3100 MW). The island was therefore able to remain in relatively stable operation. Southwestern Connecticut had separated along with southeast New York and was blacked out, while about 140 MW in northern Vermont was also deenergized, apparently in reaction to oscillations over a 4.5-s interval that drove voltage as low as 0.21 p.u. A small amount of load had been shed by underfrequency load-shedding (UFLS) relays that had acted above the standard threshold of 59.3 Hz for the first stage of UFLS in New England. Significant oscillations were reported, possibly due to a misalignment of frequency bias with actual generation frequency response. The status of the New England system after the event is shown in Figure 2.

Voltage was initially high after the separation but fell rapidly owing to the tripping of capacitors (both transmission and distribution) by overvoltage protection and a load increase over the next 7–10 minutes. At 4:16 p.m., all fast-start generation was ordered online. Due to flows on transmission lines over long-term

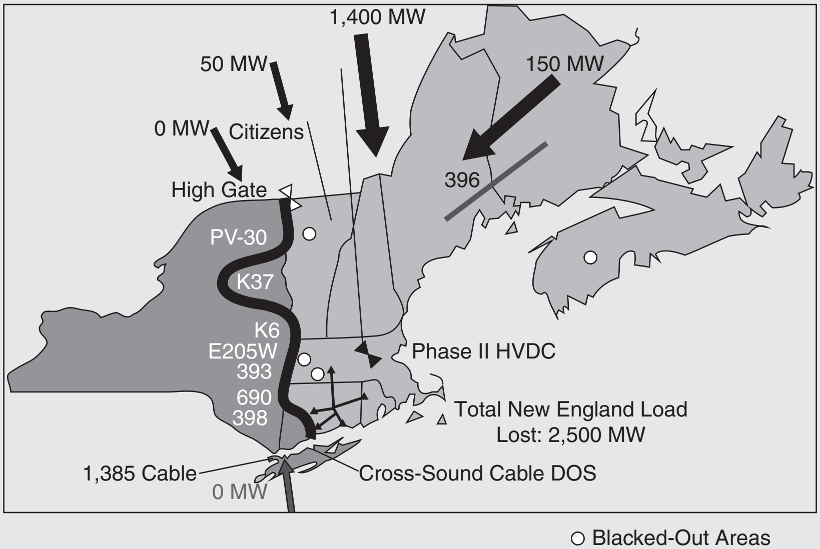

Figure 2 The New England power system island

emergency ratings and low voltages that prevented generation synchronization, CONVEX (a local transmission operator) ordered 500 MW of manual load shedding (400 MW in Connecticut and 100 MW in western Massachusetts), which was completed by 4:40 p.m. Over the next hour and 10 minutes, 400 MW of generation was synchronized to the system. The load that had been manually shed was restored between 5:42 p.m. and 7:28 p.m.

Restoration of power to southwestern Connecticut was an ongoing task. Stations were manually staffed in southwestern Connecticut. At 9:50 p.m., Danbury, Norwalk, and Stamford were reconnected. At 11:23 p.m., the Connecticut transmission system was restored except for the ties to New York and the connections to the Middle River substation, which were high-pressure, fluid-filled cables. By 1:35 a.m. on August 15, all distribution buses at bulk substations were energized except for Middle River. Restoration efforts in the area were complicated by a conductor splice failure on the Southington–Frost Bridge 345-kV line, which tripped at 5:44 a.m. Restoration of load was halted from 7 a.m. to noon, though no additional load shedding was needed. Load restoration was completed by the evening of August 15. The Norwalk-Northport 138-kV cable under Long Island Sound was not restored until August 24, however, due to the loss of cable insulation pressure.

Several lessons were learned from the New England experience:

- Some generators were not operating with automatic voltage regulators (AVRs) in voltage control mode, which hampered efforts to maintain stability of the islanded system and maintain voltages within emergency limits.

- It was concluded that operators should switch from tie line bias to flat-frequency automatic generation control (AGC) when the system becomes islanded.
- Generator governor response needed to be reviewed.
- Frequency and voltage match criteria for the resynchronization of islands needed to be reviewed.
- It was found that personnel are needed to transcribe critical decisions and actions.
- Communications improvements, such as the ability to keep a teleconference line between control centers open continuously, were also recommended.

Ontario

In restoring the system in Ontario, the first steps taken were to confirm the extent of the disturbance and to activate the Ontario Power System Restoration Plan, which includes establishing communications with other control areas, transmission owners, and market participants. Loads that have top priority in the restoration plan include class IV ac power to all nuclear sites, critical transmission and generation station service loads, and critical utility telecommunication facilities. The next priority is restoration of customer loads as necessary to control voltages and secure generators, and the priority that follows that one is synchronization of islands to each other and to neighboring power systems.

The Ontario system was completely blacked out, except for the portion of northern Ontario west of Wawa, two islands in the vicinity of Niagara and Cornwall (both of which were connected to upstate New York), and two other small islands (one north of Timmins and the other on the Ottawa River near Deep River). Transmission was restored from Niagara to the Bruce nuclear generating station starting at 4:42 p.m. The Ontario restoration paths are depicted in Figure 3. This path also provided potential for restarting the Nanticoke units. The three available Bruce units were restored from 7:13 p.m. to 9:13 p.m. Restoration continued toward the Toronto area, Pickering, and Lambton (on the border with Michigan). Controlled customer (load) restoration took place between London and Toronto to balance the transmission system. The Ontario restoration paths are depicted in Figure 3.

Meanwhile, an assessment of the Cornwall area was conducted between 4:11 p.m. and 5:15 p.m. Starting at 5:15 p.m., restoration began westward toward Pickering and Darlington. At 6:40 p.m., restoration of a path from Cornwall to Ottawa was begun in order to energize critical communication facilities. A Darlington unit was restored at 9:18 p.m. At 10:37 p.m., a transmission loop was completed around Lake Ontario.

Starting from a small remaining island, at 7:41 p.m. a path was energized south to Timmins. Load was restored, and the restoration continued south to Sudbury. This restoration

Figure 3 Ontario power system restoration paths

path reached southern Ontario at 3:43 a.m. on August 15. Northern Ontario was resynchronized to the rest of the province at Wawa at 5:20 a.m.

Immediately following the disturbance, 11 nuclear units were off-line. These units posed a number of special challenges. Fully powering down these reactors would have left them all off-line for several days, owing to the complications of restarting them. It was difficult, however, to maintain them at minimum power generation levels for the amount of time required to restore the transmission system and provide suitable outlets for their power. At Pickering B, the pumps in the emergency cooling system were unavailable for five and a half hours. In the end, three of four units at Bruce and one of four units at Darlington were able to come back online and support the system after several hours, but the remaining units were not available for several days. One unit at Bruce required repairs and was out for nine days, while one unit at Pickering did not return until two weeks after the initial disturbance. Ontario remained in a state of emergency operation for nine days because of capacity issues. Some parts of Ontario experienced rolling blackouts during this time.

The experience in Ontario provided a number of lessons learned:

- The devices in place to protect equipment operated as planned.
- The development and maintenance of a documented restoration plan, with training and rehearsals, were essential investments of time and money.
- Close cooperation among multiple entities, transmission owners and operators, generation owners and operators, the Independent Market Operator (now known as the Independent Electricity System Operator), market participants, and government, is needed.
- Communication protocols between different control areas and reliability coordinators are important.
- Emergency power at key facilities is crucial. A backup diesel generator at a Hydro One control center failed to start. The emergency operations center at the Canadian Nuclear Safety Commission in Ottawa had no backup power supply.

Detroit

The restoration effort in metropolitan Detroit was hampered by several instances of physical damage to equipment as well as a complete blackout of much of the area. Essentially, all of metropolitan Detroit and southeastern Michigan was blacked out, with only the northern part of the area known as the Thumb and a single connection from the west and south still energized.

The basic restoration plan started with the energization of the 120-kV network around Detroit from the still-energized grid to the west and north, which was synchronized with the Eastern Interconnection. Meeting this objective was followed by energization of the parallel 345-kV network. Starting from the north, energization was extended to the Harbor Beach unit from two 120-kV ties to Consumers Energy in central Michigan. Energization reached the 120-kV St. Clair station at 8:15 p.m. A stronger tie to Consumers Energy was established when the 345-kV Hampton-Pontiac line was closed in after midnight. The Remer station and the Dean power plant were reconnected at 3:18 a.m. on August 15. A 345-kV path from Belle River to St. Clair and Jewel was closed at 4:43 a.m. (see Figure 4).

On the south side, energization was extended from the Monroe 345-kV station to Brownstown and Fermi between 10:00 p.m. and 10:30 p.m. At 3 a.m. on August 15, a 120-kV connection to the Airport substation was energized, enabling restoration of critical load. But access to River Rouge and other southern generating plants was hampered by a fire at an oil refinery at the time of the blackout that forced an

Figure 4 Eastern Michigan power system restoration (orange lines indicate 500 kV, red lines indicate 345 kV, and blue lines indicate 230 kV)

evacuation of the area. Extension of energization to the Waterman station near downtown Detroit was therefore delayed until 8:00 a.m. With the closure of the Blackfoot-Madrid 345-kV line at 8:55 a.m. and the closure of the ring bus at Pontiac at 9:30 a.m., the 345-kV loop around the Detroit metro area was finally reestablished. A second 345-kV tie to Consumers Energy, the Thetford-Jewel circuit, was reclosed at 1:38 p.m. on August 15.

As restoration continued, Detroit Edison followed a practice of energizing whole distribution centers without isolating individual circuits. Up to this point, most of the restoration actions were preparatory to restoring load. Distribution crews were needed as transmission was restored in order to balance load against available generation. Substantial restoration of distribution started at about 2:30 p.m. on August 15. The restoration of the Essex 24-kV station at 5:30 p.m. picked up a significant portion of the load in the city of Detroit. The last of four critical pumps for the city's water and sanitation department was restored in the evening.

Detroit Edison conducted inspections of transmission lines and switchyards over the next several days to maintain system reliability. The inspections were conducted both by air and on the ground, and they were both visual and thermal. Storms delayed the start of the inspections. Approximately 1500 mi. of transmission were inspected between August 17 and 21.

Several instances of damage to generators were reported. Five units had failed rupture discs, which kept these units unavailable for more than 24 hours. Rupture discs are a pressure relief location for the steam condenser. They are prone to failure when the entire electrical network goes down, as a consequent loss of circulating water pumps and vacuum pumps results in a buildup of pressure in the condenser. The rupture discs, however, are designed to fail under stressed conditions and probably prevented serious physical damage to the units. The availability of spare discs so that units could be returned to service was an issue; the need for so many simultaneous rupture disc replacements had not been experienced previously. One unit suffered a loss of control air on the generator seal oil system valves, resulting in oil in the generator. The output of another unit was limited due to a ground in the no load/low load trip switch. Another unit had an overheated boiler circulating water pumps, which needed to be replaced. Finally, one unit (River Rouge 3) suffered bearing damage during the event, which left the unit out of service for weeks. Lessons learned from the restoration experience in and around Detroit include:

- The restoration effort was vulnerable to Detroit Edison's computerized "in-service application" function, used to prioritize and dispatch repair crews. This function was not operable due to the loss of power, forcing repair crews to make a number of extra trips back to service centers to pick up new work orders.
- Practices in maintaining spare rupture discs for generators were deficient for coping with system-wide disturbances and hence were changed.

Southern Michigan

The southeastern corner of the Consumers Energy system in southern Michigan had also blacked out. After the initial disturbance, operators received conflicting information about the amount of generation. Operators believed the Consumers Energy system was undergenerating, but the high frequency (60.2 Hz) suggested the opposite. Operators maintained generation levels until the status of the system could be ascertained. Restoration efforts commenced with an emergency page of transmission and distribution personnel and a conference call at 5:15 p.m. on August 14 to determine initial actions. After assessing the state of the transmission system and identifying the affected area, all of the breakers within that area were opened as preparation for restoration. The 138-kV network was restored by 7:25 p.m. Subsequently, the remaining 46-kV lines and customer load were restored; this work was completed by 10:05 p.m.

The area that was restored was fed by three 138-kV lines. One of the lines (Leoni-Beecher) tripped at 10:30 p.m. and did not reclose. The power increase on the other two lines caused them to trip as well, blacking out the area that had just been restored. A second restoration commenced quickly, bringing the 138-kV network back up by 12:55 a.m. on August 15 and the 46-kV network, with all customer load, by 1:35 a.m. A fault location was identified from relay data, but a cause for the fault was not found at the indicated location. The line was given a derated capability when it was reclosed at 11:00 p.m. Because of the limitations of the system caused by the derating, 40 MW of load, served by four 46-kV lines, was manually shed between 7 a.m. and 9:30 a.m. on August 15; the lines were restored when a Whiting generator came back online.

The initial attempt to return the Campbell 3 unit to service failed due to water hammer that developed after steam was turned back on. The water hammer damaged a number of piping hangers, delaying the unit's return to service.

Cleveland

The authors could not find any publicly available, comprehensive reports on the restoration process in the Cleveland area. A summary of the restoration in the region of the East Central Area Reliability Coordination Agreement (ECAR), which includes northern Ohio and southern Michigan, is provided from the ECAR final report dated July 7, 2004. In the region, 18,047 MW of load, 18,811 MW of generation, and 238 transmission circuits were lost. All load was restored by 9:00 a.m. on August 16. Restoration of 100% of the load took one day and 17 hours. The restoration strategy consisted of restoration of load from energized transmission lines and the use of black-start units not in black-start mode. These gas turbines were capable of black starting but were not used in this mode. These units can be started up very quickly to help restore load. Throughout the restoration, operators needed to be sure that transfers from American Electric Power (AEP) to Michigan did not overload the FirstEnergy transmission system in northern Ohio. Restoration of power to off-site nuclear power plant supply and to other generation resources off-line as a result of the blackout was a priority. Communications and fuel supply to critical infrastructure were major issues during the blackout restoration effort. The need to more effectively share restoration plans among reliability coordinators, transmission operators, and generation operators was identified. ECAR also identified the need for additional training and regular drills for blackout restoration.

State or Province	Time to Restore Substantial Load	Time to Restore 100% Load
Michigan	8/15/2003 at 5:30 p.m.	8/15/2003, evening
New England	8/15/2003 at 1:35 a.m.	8/15/2003, end of day
New York	8/15/2003 at 4:00 a.m.	8/15/2003 at 10:30 p.m.
Ohio	8/15/2003 at 7:00 a.m. (Cleveland water pumps)	8/16/2003 at 7:00 a.m. (as reported by ECAR)
Ontario	Data not publicly available	8/15/2003, end of day

TABLE 1

Time to restore substantial and 100% load for the various regions affected, as reported in publicly available documentation

Restoration Summary

The times to restore substantial and 100% load for the various regions affected by the blackout are given in Table 1.

Lessons Learned

A general pattern for sound restoration can be inferred from these examples. Restoration commences by first assessing the current state of the system. Then a skeletal high-voltage network is reassembled, providing a cranking path for generation, followed by the gradual connection of lower-voltage facilities and customer load. Of course, the process is not quite this simple. Some load is needed on the system throughout the restoration process in order to maintain voltage stability; otherwise, voltages become excessively high, to the point of potentially damaging equipment. Reactive devices alone are insufficient to regulate voltage on an unloaded transmission system. The system is vulnerable throughout the process: at least one instance was observed of a fully restored area collapsing, forcing utility personnel to start all over again.

The ability to tie to a large interconnection makes the restoration process easier and smoother. A large interconnection provides very stable frequency control and, to a lesser extent, voltage control. Maintaining voltage and frequency in a smaller island is considerably more difficult. In several such instances, operators found it necessary to manually shed load to prevent a complete collapse of the remaining system.

Operators must prioritize critical loads during restoration. Such loads, at the bulk power system level, include water and sanitation system pumps, off-site power for nuclear generating stations, and airports.

The old cliché "expect the unexpected" is certainly applicable to a system restoration effort. Despite the thoughtful development of restoration plans, a number of unforeseen difficulties arose throughout the process, including damaged generators, the inability to synchronize due to excessive voltage disparities, and an inability to physically reach substations due to industrial hazards spawned by the power outage. Communications was cited as an issue in nearly all areas; communication systems need to be able to function in the absence of the power grid. Similar flaws in emergency plans were seen following Hurricane Katrina: officials anticipated being able to use cellular phones following the storm, but many cellular towers were inoperable.

To summarize, the lessons learned included the following priorities and steps:

- Improve communications among responsible parties and communication systems.
- Develop and maintain a restoration plan, and always be prepared to "expect the unexpected."
- Restoration begins by first assessing the current state of the system.
- The next step is to reassemble a skeletal high-voltage network.
- Then a "cranking" path for generation must be provided so as to assure the system is stable and will be restored without sustaining excessive voltages.
- Gradually connect lower voltage facilities and customer load to maintain voltage stability. Reactive devices alone are insufficient to regulate voltage on an unloaded transmission system.
- The availability of connection to a large interconnection makes frequency control and voltage control more stable.
- Shed load if need be to maintain stability within an island being restored.
- Prioritize critical loads during restoration.

Regulatory Recommendations and Standards

Most of the recommendations that followed the postmortem analysis of the blackout focused on preventing a cascading outage as opposed to recovering from one. Recommendation 29 from the U.S.-Canada Power System Outage Task Force, however, was as follows: "Evaluate and disseminate lessons learned during system restoration." In the aftermath of the blackout, the North American Electric Reliability Council (NERC) developed a number of reliability standards to minimize the likelihood of major blackouts and mitigate their impact should they occur. Two particular standards—EOP-005-2 and EOP-006-2—address system restoration. EOP-005-2 provides standards regarding the use of black-start units to reliably restore the system after a blackout. Some of the lessons learned in the August 14 blackout, such as identifying key strategies for establishing cranking paths and adding load incrementally to stabilize voltage and frequency, were incorporated into EOP-005-2. NERC Standard EOP-006-2 addresses the need for coordination of restoration plans among reliability coordinators, the need for plans to achieve synchronization between islands formed by the blackout and the need for training and simulation drills at prescribed periods to ensure that the main ties among reliability coordinators are restored in a reliable manner. While the emphasis remains on preventing blackouts in the first place, it is important to have thoughtful and coordinated plans to restore the power system reliably, particularly in view of the ever present-threat of natural disasters such as fires, floods, and hurricanes.

Conclusion

On August 14, 2003, an enormous power disruption resulted in the loss of power to approximately 50 million people. A total of 61,800 MW of load was disconnected, along with 265 generating plants (see Figure 5). Three major metropolitan areas (Cleveland, Detroit, and New York), along with much of the province of Ontario, were blacked out. Two large areas (upstate New York and the combination of New England and the Maritime provinces) and several smaller areas became electrically islanded systems, disconnected from the Eastern Interconnection. Overall, given the difficulties confronted, the affected utilities and their dedicated personnel did an admirable job in overcoming those difficulties and restoring the power system following this historic power outage.

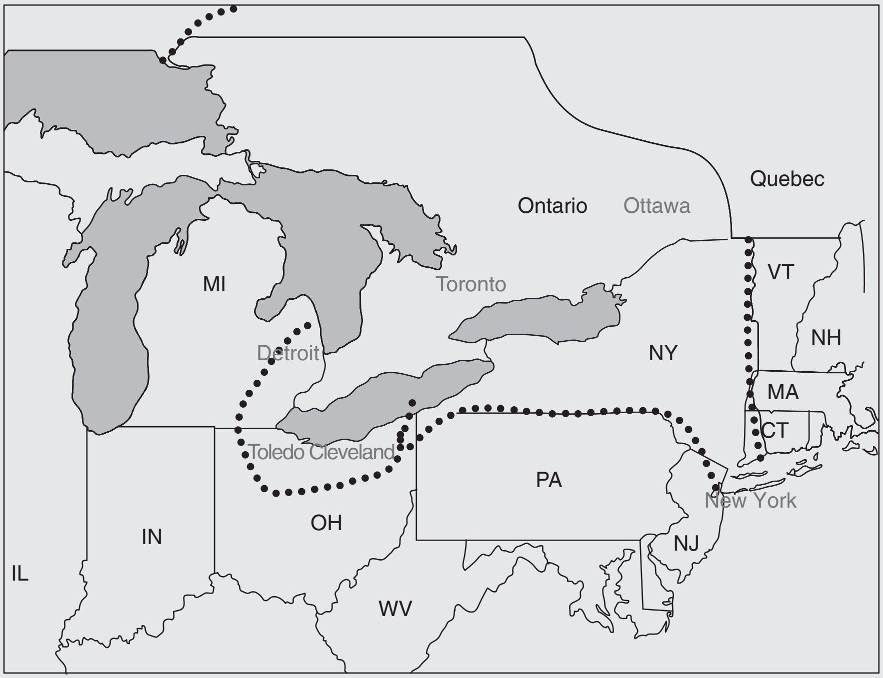

Figure 5 The area affected by August 14, 2003 blackout

For Further Reading

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12.1 GENERATOR-VOLTAGE CONTROL

The *exciter* delivers dc power to the field winding on the rotor of a synchronous generator. For older generators, the exciter consists of a dc generator driven by the rotor. The dc power is transferred to the rotor via slip rings and brushes. For newer generators, *static* or *brushless* exciters are often employed.

For static exciters, ac power is obtained directly from the generator terminals or a nearby station service bus. The ac power is then rectified via thyristors and transferred to the rotor of the synchronous generator via slip rings and brushes.

For brushless exciters, ac power is obtained from an "inverted" synchronous generator whose three-phase armature windings are located on the main generator rotor and whose field winding is located on the stator.

The ac power from the armature windings is rectified via diodes mounted on the rotor and is transferred directly to the field winding. For this design, slip rings and brushes are eliminated.

Block diagrams of several standard types of generator-voltage control systems have been developed by the IEEE Power and Energy Society, beginning in 1968 with [1] and most recently in 2005 with IEEE Std 421.5-2005. A block diagram for what is commonly known as the IEEE Type 1 exciter, which uses a shaft-driven dc generator to create the field current, is shown in Figure 12.3 (neglecting saturation).

In Figure 12.3, the leftmost block, $1/(1 + sT_r)$, represents the delay associated with measuring the terminal voltage V_t where s is the Laplace operator and T_r is the measurement time constant. Note that if a unit step is applied to a $1/(1 + sT_r)$ block, the output rises exponentially to unity with time constant T_r. The measured generator terminal voltage V_t is compared with a voltage reference V_{ref} to obtain a voltage error, ΔV, which in turn is applied to the voltage regulator. The voltage regulator is modeled as an amplifier with gain K_a and a time constant T_a, while the last forward block represents the dynamics of the exciter's dc generator. The output is the field voltage E_{fd}. which is applied to the generator field winding and acts to adjust the generator terminal voltage, as in (11.6.5). The feedback block in Figure 12.3 is used to improve the dynamic response of the exciter by reducing excessive overshoot. This feedback is represented by $(sK_f)/(1 + sT_f)$, which provides a filtered first derivative negative feedback.

For any transient stability study, the initial values for the state variables need to be determined. This is done by assuming that the system is initially operating in steady-state, and recognizing that in steady-state all the derivatives will be zero. Then, by knowing the initial field voltage (found as in Example 11.10) and terminal voltage, all the other variables can be determined.

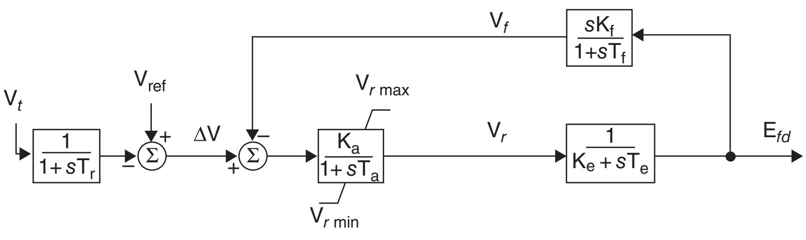


FIGURE 12.3

Block diagram for the IEEE Type 1 Exciter (neglecting saturation)

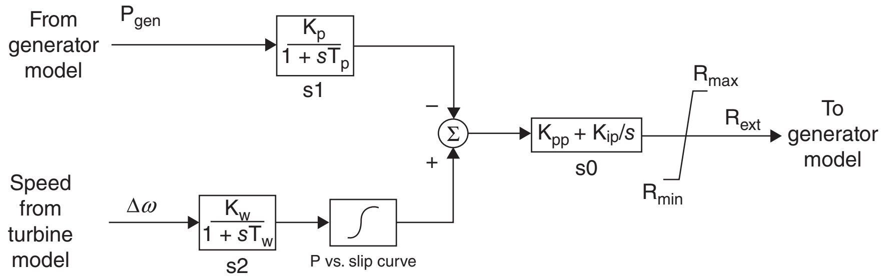


FIGURE 12.4 Simplified block diagram for a Type 2 wind turbine R_{ext} control system

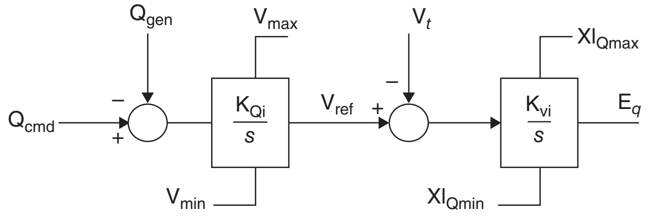


FIGURE 12.5 Simplified block diagram for a Type 3 wind turbine reactive power control system

For wind turbines, how their voltage is controlled depends upon the type of the wind turbines. Type 1 wind turbines, squirrel cage induction machines, have no direct voltage control. Type 2 wind turbines are wound rotor induction machines with variable external resistance. While they do not have direct voltage control, the external resistance control system is usually modeled as a type of exciter. The block diagram for such a model is shown in Figure 12.4. The purpose for this control is to allow for a more constant power output from the wind turbine. For example, if a wind gust were to cause the turbine blades to accelerate, this controller would quickly increase the external resistance, flatting the torque-speed curve as shown in Figure 11.25.

Similar to synchronous machines, the Type 3 and 4 wind turbines have the ability to perform voltage or reactive power control. Common control modes include constant power factor control, coordinated control across a wind farm to maintain a constant voltage at the interconnection point, and constant reactive power control. Figure 12.5 shows a simplified version of a Type 3 wind turbine exciter, in which Q_{cmd} is the commanded reactive power, V_t is the terminal voltage, and the output, E_q is the input to the DFAG model shown in Figure 11.27. For fixed reactive power Q_{cmd} is a constant, while for power factor control, Q_{cmd} varies linearly with the real power output.

EXAMPLE 12.1

Synchronous Generator Exciter Response

Using the system from Example 11.10, assume the two-axis generator is augmented with an IEEE Type 1 exciter with $T_r = 0$, $K_a = 100$, $T_a = 0.05$, $V_{r\max} = 5$, $V_{r\min} = -5$, $K_e = 1$, $T_e = 0.26$, $K_a = 0.01$ and $T_f = 1.0$. (a) Determine the initial values of V_r, V_f, and V_{ref}. (b) Using the fault sequence from Example 11.10, determine the bus 4 terminal voltage after 1 second and then after 5 seconds.

SOLUTION

a. The initial field voltage and terminal voltage, E_{fd} and V_t, do not depend on the exciter, so their values are equal to those found in Example 11.10, that is, 2.913 and 1.095 respectively. Since the system is initially in steady-state,

$$V_r = (K_e)(E_{fd}) = (1.0)(2.9135) = 2.9135$$

Because V_f is the output of the filtered derivative feedback, its initial value is zero. Finally, writing the equation for the second summation block in Figure 12.3

$$(V_{ref} - V_t - V_f)(K_a) = V_r$$

$$V_{ref} = \frac{V_r}{K_a} + V_t + V_f = \frac{2.9135}{100} + 1.0946 = 1.1237$$

b. Open PowerWorld Simulator case Example 12_1 and display the Transient Stability Analysis Form (see Figure 12.6). To see the initial conditions, select the

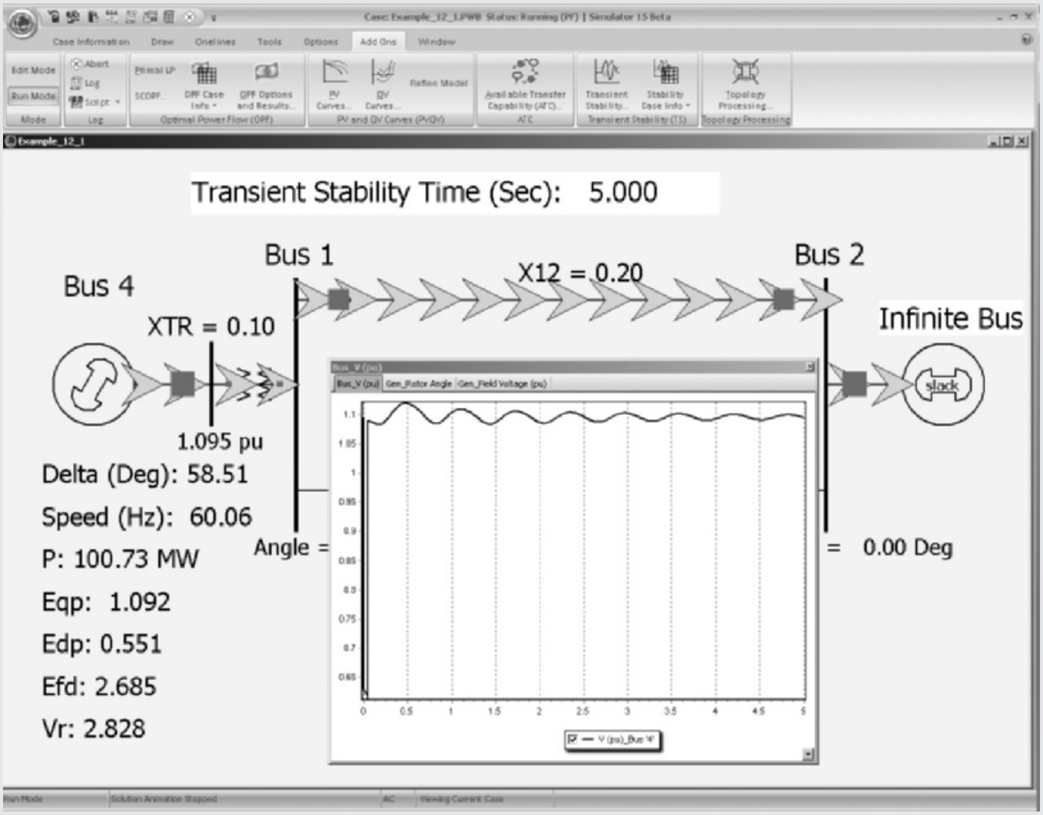


FIGURE 12.6

Example 12.1 results

(Continued)

States/Manual Control page, and then select the **Transfer Present State to Power Flow** button to update the oneline display. From this page, it is also possible to just do a specified number of timesteps by selecting the **Do Specified Number of Timesteps(s)** button or to run to a specified simulation time using the **Run Until Specified Time** button. To determine the terminal voltage after one second, select the **Run Until Specified Time** button. The value is 1.10 p.u. To finish the simulation, select the **Continue** button. The terminal voltage at five seconds is 1.095 p.u., which is close to the prefault voltage, indicating the exciter is restoring the voltage to its setpoint value. In contrast, the bus 4 terminal voltage after five seconds in the Example 11.10 case, which does not include an exciter, is 1.115 p.u.

EXAMPLE 12.2

Type 3 Wind Turbine Reactive Power Control

Assume the Type 3 wind turbine from Example 11.12 has a Figure 12.5 reactive power control system with $K_{Qi} = 0.4$, $K_{Vi} = 40$, $XI_{Qmax} = 1.45$, $XI_{Qmin} = 0.5$, $V_{max} = 1.1$, $V_{min} = 0.9$ (per unit using a 100 MVA base). For the Example 11.12 system conditions, determine the initial values for V_{ref}, Q_{cmd}, and estimate the maximum amount of reactive power this system could supply during a fault that depresses the terminal voltage to 0.5 p.u.

SOLUTION

Since in steady-state the inputs to each of the two integrator blocks in Figure 12.5 must be zero, V_{ref} is just equal to the initial terminal voltage magnitude from Example 11.12, that is, 1.0239 p.u., and Q_{cmd} is the initial reactive power output, which is 0.22 per unit (22 Mvar), found from the imaginary part of the product of the terminal voltage and the conjugate of the terminal current. During the fault with its low terminal voltage, the positive input into the K_{Vi}; integration block will cause E_q to rapidly rise to its limit $XI_{Qmax} = 1.45$. The reactive component of I_{sorc} will then be $-1.45/\,0.8 = -1.8125$ p.u. The total per unit reactive power injection with $V_t = 0.5$ during the fault is then

$$Q_{net} = (V_t)(1.8125) - \frac{V_t^2}{0.8} = 0.593 \text{ pu} = 59.3 \quad \text{Mvar}$$

This result can be confirmed by opening PowerWorld Simulator case Example 12_2 which models such a fault condition (see Figure 12.7). After the fault is cleared, the reactive power controller restores the machine's reactive power output to its prefault value.

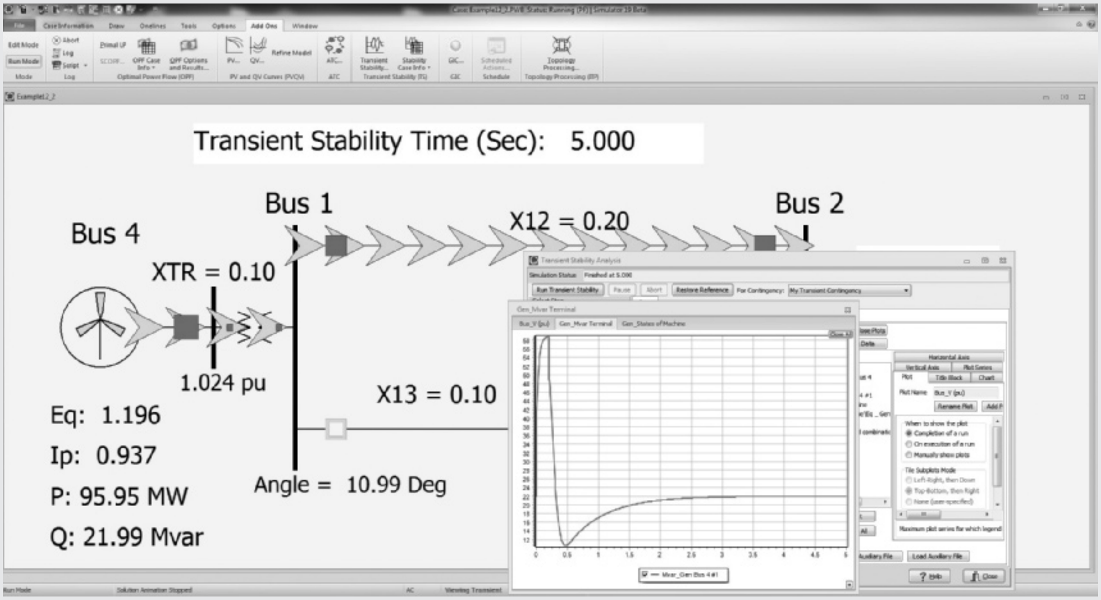


FIGURE 12.7

Example 12.2 variation in generator reactive power output

Block diagrams such as those shown in Figure 12.3 are used for computer representation of generator-voltage control in transient stability computer programs (see Chapter 11). In practice, high-gain, fast-responding exciters provide large, rapid increases in field voltage E_{fd} during short circuits at the generator terminals in order to improve transient stability after fault clearing. Equations represented in the block diagram can be used to compute the transient response of generator-voltage control.

12.2 TURBINE-GOVERNOR CONTROL

Turbine-generator units operating in a power system contain stored kinetic energy due to their rotating masses. If the system load suddenly increases, stored kinetic energy is released to initially supply the load increase. Also, the electrical torque T_e of each turbine-generating unit increases to supply the load increase, while the mechanical torque T_m of the turbine initially remains constant. From Newton's second law, $J\alpha = T_m - T_e$, the acceleration α is therefore negative. That is, each turbine-generator decelerates and the rotor speed drops as kinetic energy is released to supply the load increase. The electrical frequency of each generator, which is proportional to rotor speed for synchronous machines, also drops.

From this, we conclude that either rotor speed or generator frequency indicates a balance or imbalance of generator electrical torque T_e and turbine mechanical torque T_m. If speed or frequency is decreasing, then T_e is greater than T_m (neglecting generator losses). Similarly, if speed or frequency is increasing, T_e is less than T_m. Accordingly, generator frequency is an appropriate control signal for governing the mechanical output power of the turbine.

The steady-state frequency-power relation for turbine-governor control is

$$\Delta p_m = \Delta p_{\text{ref}} - \frac{1}{R}\Delta f \tag{12.2.1}$$

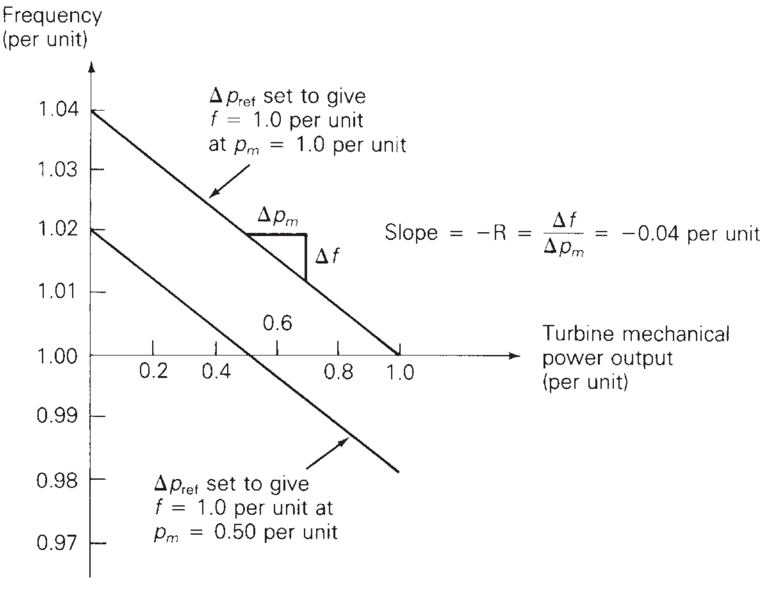
where Δf is the change in frequency, Δp_m is the change in turbine mechanical power output, and Δp_{ref} is the change in a reference power setting. R is called the *regulation constant.* The equation is plotted in Figure 12.8 as a family of curves, with Δp_{ref} as a parameter. Note that when Δp_{ref} is fixed, Δp_m is directly proportional to the drop in frequency.

Figure 12.8 illustrates a steady-state frequency-power relation. When an electrical load change occurs, the turbine-generator rotor accelerates or decelerates, and frequency undergoes a transient disturbance. Under normal operating conditions, the rotor acceleration eventually becomes zero, and the frequency reaches a new steady-state, shown in the figure.

The regulation constant R in (12.2.1) is the negative of the slope of the Δf versus Δp_m curves shown in Figure 12.8. The units of R are Hz/MW when Δf is in Hz and Δp_m is in MW. When Δf and Δp_m are given in per-unit, however, R is also in per-unit.

FIGURE 12.8

Steady-state frequency–power relation for a turbine-governor



EXAMPLE 12.3

Turbine-governor response to a frequency change at a generating unit

A 500-MVA, 60-Hz turbine-generator has a regulation constant R = 0.05 per unit based on its own rating. If the generator frequency increases by 0.01 Hz in steady-state, what is the decrease in turbine mechanical power output? Assume a fixed reference power setting.

SOLUTION

The per-unit change in frequency is

$$\Delta f_{\text{p.u.}} = \frac{\Delta f}{f_{\text{base}}} = \frac{0.01}{60} = 1.6667 \times 10^{-4} \quad \text{per unit}$$

Then, from (12.2.1), with $\Delta p_{\text{ref}} = 0$,

$$\Delta p_{m\text{p.u.}} = \left(\frac{-1}{0.05}\right)(1.6667 \times 10^{-4}) = -3.3333 \times 10^{-4} \quad \text{per unit}$$

$$\Delta p_m = (\Delta p_{m\text{p.u.}})\text{S}_{\text{base}} = (-3.3333 \times 10^{-4})(500) = -1.6667 \quad \text{MW}$$

The turbine mechanical power output decreases by 1.67 MW.

The steady-state frequency-power relation for one area of an interconnected power system can be determined by summing (12.2.1) for each turbine-generating unit in the area. Noting that Δf is the same for each unit,

$$\begin{aligned}\Delta p_m &= \Delta p_{m1} + \Delta p_{m2} + \Delta p_{m3} + \cdots \\ &= (\Delta p_{\text{ref1}} + \Delta p_{\text{ref2}} + \cdots) - \left(\frac{1}{\text{R}_1} + \frac{1}{\text{R}_2} + \cdots\right)\Delta f \\ &= \Delta p_{\text{ref}} - \left(\frac{1}{\text{R}_1} + \frac{1}{\text{R}_2} + \cdots\right)\Delta f \end{aligned} \tag{12.2.2}$$

where Δp_m is the total change in turbine mechanical powers and Δp_{ref} is the total change in reference power settings within the area. We define the *area frequency response characteristic* β as

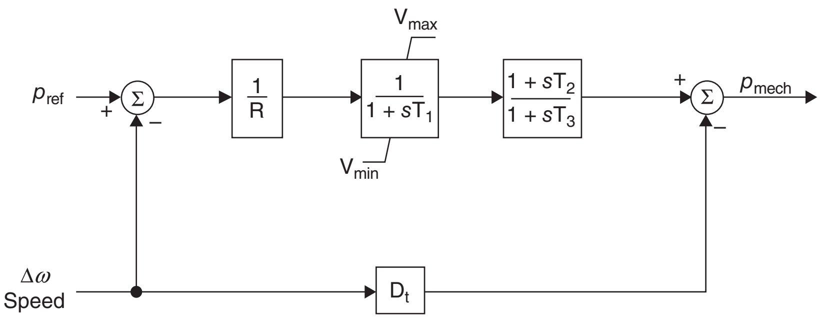
$$\beta = \left(\frac{1}{\text{R}_1} + \frac{1}{\text{R}_2}\cdots\right) \tag{12.2.3}$$

Using (12.2.3) in (12.2.2),

$$\Delta p_m = \Delta p_{\text{ref}} - \beta\Delta f \tag{12.2.4}$$

FIGURE 12.9

Turbine-governor block diagram



Equation (12.2.4) is the area steady-state frequency-power relation. The units of β are MW/Hz when Δf is in Hz and Δp_m is in MW. β can also be given in per-unit. In practice, β is somewhat higher than that given by (12.2.3) due to system losses and the frequency dependence of loads.

A standard value for the regulation constant is R = 0.05 per unit. When all turbine-generating units have the same per-unit value of R based on their own ratings, then each unit shares total power changes in proportion to its own rating. Figure 12.9 shows a block diagram for a simple steam turbine governor commonly known as the TGOV1 model. The $1/(1 + sT_1)$ models the time delays associated with the governor, where s is again the Laplace operator and T_1 is the time constant. The limits on the output of this block account for the fact that turbines have minimum and maximum outputs. The second block diagram models the delays associated with the turbine; for non-reheat turbines T_2 should be zero. Typical values are R = 0.05 p.u., T_1 =0.5 seconds, T_3 = 0.5 for a non-reheat turbine or T_2 = 2.5 and T_3 = 7.5 seconds otherwise. D_t, is a turbine damping coefficient that is usually 0.02 or less (often zero). Additional turbine block diagrams are available in [3].

EXAMPLE 12.4

Response of turbine-governors to a load change in an interconnected power system

An interconnected 60-Hz power system consists of one area with three turbine-generator units rated 1000, 750, and 500 MVA, respectively. The regulation constant of each unit is R = 0.05 per unit based on its own rating. Each unit is initially operating at one-half of its own rating, when the system load suddenly increases by 200 MW. Determine (a) the per-unit area frequency response characteristic β on a 1000 MVA system base, (b) the steady-state drop in area frequency, and (c) the increase in turbine mechanical power output of each unit. Assume that the reference power setting of each turbine-generator remains constant. Neglect losses and the dependence of load on frequency.

SOLUTION

a. The regulation constants are converted to per-unit on the system base using

$$R_{\text{p.u.new}} = R_{\text{p.u.old}} \frac{S_{\text{base(new)}}}{S_{\text{base(old)}}}$$

We obtain

$$R_{1\text{p.u.new}} = R_{1\text{p.u.old}} = 0.05$$

$$R_{2\text{p.u.new}} = (0.05)\left(\frac{1000}{750}\right) = 0.06667$$

$$R_{3\text{p.u.new}} = (0.05)\left(\frac{1000}{550}\right) = 0.10 \quad \text{per unit}$$

Using (12.2.3),

$$\beta = \frac{1}{R_1} + \frac{1}{R_2} + \frac{1}{R_3} = \frac{1}{0.05} + \frac{1}{0.06667} + \frac{1}{0.10} = 45.0 \quad \text{per unit}$$

b. Neglecting losses and dependence of load on frequency, the steady-state increase in total turbine mechanical power equals the load increase, 200 MW or 0.20 per unit. Using (12.2.4) with $\Delta p_{\text{ref}} = 0$,

$$\Delta f = \left(\frac{-1}{\beta}\right)\Delta p_m = \left(\frac{-1}{45}\right)(0.20) = -4.444 \times 10^{-3} \quad \text{per unit}$$

$$= (-4.444 \times 10^{-3})(60) = -0.2667 \quad \text{Hz}$$

The steady-state frequency drop is 0.2667 Hz.

c. From (12.2.1), using $\Delta f = -4.444 \times 10^{-3}$ per unit,

$$\Delta p_{m1} = \left(\frac{-1}{0.05}\right)(-4.444 \times 10^{-3}) = 0.08888 \quad \text{per unit}$$

$$= 88.88 \quad \text{MW}$$

$$\Delta p_{m2} = \left(\frac{-1}{0.06667}\right)(-4.444 \times 10^{-3}) = 0.06666 \quad \text{per unit}$$

$$= 66.66 \quad \text{MW}$$

$$\Delta p_{m3} = \left(\frac{-1}{0.10}\right)(-4.444 \times 10^{-3}) = 0.04444 \quad \text{per unit}$$

$$= 44.44 \quad \text{MW}$$

Note that unit 1, whose MVA rating is 33% larger than that of unit 2 and 100% larger than that of unit 3, picks up 33% more load than unit 2 and 100% more

(*Continued*)

load than unit 3. That is, each unit shares the total load change in proportion to its own rating.

PowerWorld Simulator case Example 12_4 contains a lossless nine bus, three generator system that duplicates the conditions from this example (see Figure 12.10). The generators at buses 1, 2 and 3 have ratings of 500, 1000, and 750 MVA respectively, with initial outputs of 300, 600, 500 MWs. Each is modeled with a two-axis synchronous machine model (see Section 11.6), an IEEET1 exciter and a TGOV1 governor model with the parameters equal to the defaults given earlier. At time t = 0.5 seconds, the load at bus 8 is increased from 200 to 400 MW. Figure 12.10 shows the results of a 10-second transient stability simulation. The final generator outputs are 344.5, 589.0, and 466.7 MWs, while the final frequency decline is 0.272 Hz, closely matching the results predicted in the example (the frequency decline exactly matches the 0.266 Hz prediction if the simulation is extended to 20 seconds).

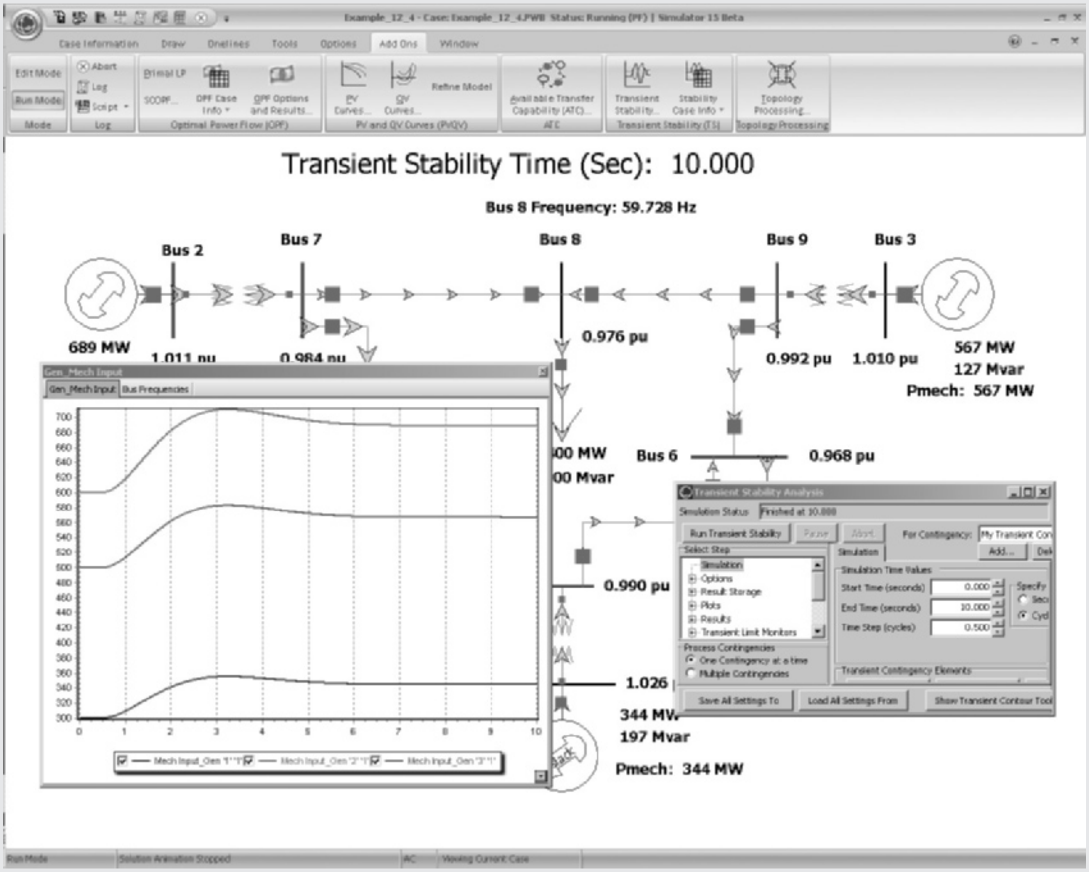


FIGURE 12.10

System oneline with generator mechanical power variation for Example 12.4

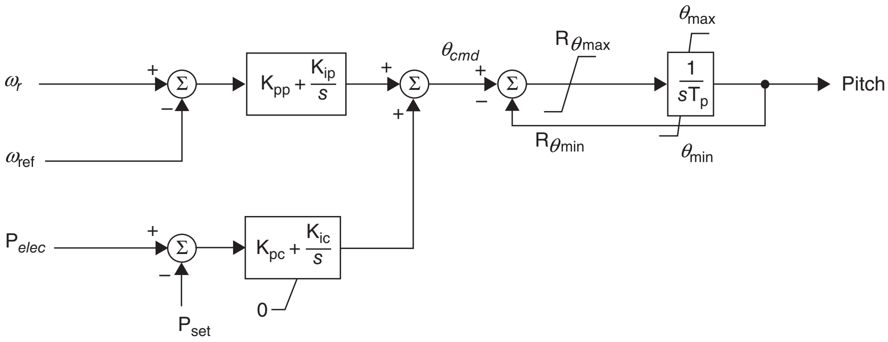


FIGURE 12.11

Pitch control for a Type 3 or 4 wind turbine model

The power output from wind turbines can be controlled by changing the pitch angle of the blades. When the available power in the wind is above the rating for the turbine, its blades are pitched to limit the mechanical power delivered to the electric machine. When the available power is less than the machine's rating, the pitch angle is set to its minimum. Figure 12.11 shows the generic pitch control model for Type 3 and 4 wind turbines, with the inputs being the per unit speed of the turbine, ω_r, the desired speed (normally 1.2 p.u.), the ordered per unit electrical output, and a setpoint power. These signals are combined as shown on the figure to produce a commanded angle for the blades, θ_{cmd}, expressed in degrees. The right side of the block diagram models the dynamics and limits associated with changing the pitch angle of the blades; R_θ is the rate at which the blades change their angle in degrees per second. Typical values are $T_p = 0.3$ seconds, $\theta_{min/max}$ between 0° and 27°, rate limits of ±10°/s, $K_{pp} = 150$, $K_{ip} = 25$, $K_{pc} = 3$, $K_{ic} = 30$.

In general, the larger the size of the interconnected system, the better the frequency response since there are more generators to share the task. However, "Owners/operators of generator units have strong economic reasons to operate generator units in many ways that prevent effective governing response." [16] For example, operating the unit at its full capacity, which maximizes the income that can be derived from the unit but prevents the unit from increasing its output. This is certainly an issue with wind turbines since their "fuel" is essentially free. Also, the Type 3 and 4 units do not contribute inertial response.

12.3 LOAD-FREQUENCY CONTROL

As shown in Section 12.2, turbine-governor control eliminates rotor accelerations and decelerations following load changes during normal operation. However, there is a steady-state frequency error Δf when the change in turbine-governor reference setting Δp_{ref} is zero. One of the objectives of load-frequency control (LFC), therefore, is to return Δf to zero.

In a power system consisting of interconnected areas, each area agrees to export or import a scheduled amount of power through transmission-line interconnections, or tie-lines, to its neighboring areas. Thus, a second LFC objective is to have each area absorb its own load changes during normal operation. This objective is achieved by maintaining the net tie-line power flow out of each area at its scheduled value.

The following summarizes the two basic LFC objectives for an interconnected power system:

1. Following a load change, each area should assist in returning the steady-state frequency error Δf to zero.
2. Each area should maintain the net tie-line power flow out of the area at its scheduled value, in order for the area to absorb its own load changes.

The following control strategy developed by N. Cohn [4] meets these LFC objectives. We first define the *area control error* (ACE) as follows:

$$\begin{aligned} \text{ACE} &= (p_{\text{tie}} - p_{\text{tie,sched}}) + \text{B}_f(f - 60) \\ &= \Delta p_{\text{tie}} + \text{B}_f \Delta_f \end{aligned} \tag{12.3.1}$$

where Δp_{tie} is the deviation in net tie-line power flow out of the area from its scheduled value $p_{\text{tie, sched}}$, and Δf is the deviation of area frequency from its scheduled value (60 Hz). Thus, the ACE for each area consists of a linear combination of tie-line error Δp_{tie} and frequency error Δf. The constant B_f is called a *frequency bias constant.*

The change in reference power setting $\Delta p_{\text{ref}i}$ of each turbine-governor operating under LFC is proportional to the integral of the area control error. That is,

$$\Delta p_{\text{ref}i} = -\text{K}_i \int \text{ACE}\, dt \tag{12.3.2}$$

Each area monitors its own tie-line power flows and frequency at the area control center. The ACE given by (12.3.1) is computed and a percentage of the ACE is allocated to each controlled turbine-generator unit. Raise or lower commands are dispatched to the turbine-governors at discrete time intervals of two or more seconds in order to adjust the reference power settings. As the commands accumulate, the integral action in (12.3.2) is achieved.

The constant K_i in (12.3.2) is an integrator gain. The minus sign in (12.3.2) indicates that if either the net tie-line power flow out of the area or the area frequency is low—that is, if the ACE is negative—then the area should increase its generation.

When a load change occurs in any area, a new steady-state operation can be obtained only after the power output of every turbine-generating unit in the interconnected system reaches a constant value. This occurs only when all reference power settings are zero, which in turn occurs only when the ACE of every area is zero. Furthermore, the ACE is zero in every area only when both Δp_{tie} and Δf are zero. Therefore, in steady-state, both LFC objectives are satisfied.

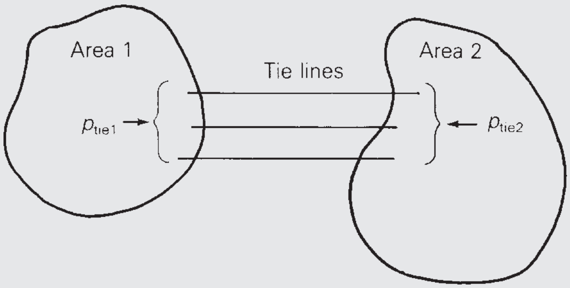
EXAMPLE 12.5

Response of LFC to a load change in an interconnected power system

As shown in Figure 12.12, a 60-Hz power system consists of two interconnected areas. Area 1 has 2000 MW of total generation and an area frequency response characteristic $\beta_1 = 700$ MW/Hz. Area 2 has 4000 MW of total generation and $\beta_2 = 1400$ MW/Hz. Each area is initially generating one-half of its total generation, at $\Delta p_{\text{tie1}} = \Delta p_{\text{tie2}} = 0$ and at 60 Hz when the load in area 1 suddenly increases by 100 MW. Determine the steady-state frequency error Δf and the steady-state tie-line error Δp_{tie} of each area for the following two cases: (a) without LFC, and (b) with LFC given by (12.3.1) and (12.3.2). Neglect losses and the dependence of load on frequency.

FIGURE 12.12

Example 12.5



SOLUTION

a. Since the two areas are interconnected, the steady-state frequency error Δf is the same for both areas. Adding (12.2.4) for each area,

$$(\Delta p_{m1} + \Delta p_{m2}) = (\Delta p_{\text{ref1}} + \Delta p_{\text{ref2}}) - (\beta_1 + \beta_2)\Delta f$$

Neglecting losses and the dependence of load on frequency, the steady-state increase in total mechanical power of both areas equals the load increase, 100 MW. Also, without LFC, Δp_{ref1} and Δp_{ref2} *are* both zero. The above equation then becomes

$$100 = -(\beta_1 + \beta_2)\Delta f = -(700 + 1400)\Delta f$$
$$\Delta f = -100/2100 = -0.0476 \quad \text{Hz}$$

Next, using (12.2.4) for each area, with $\Delta p_{\text{ref}} = 0$,

$$\Delta p_{m1} = -\beta_1 \Delta f = -(700)(-0.0476) = 33.33 \quad \text{MW}$$
$$\Delta p_{m2} = -\beta_2 \Delta f = -(1400)(-0.0476) = 66.67 \quad \text{MW}$$

In response to the 100-MW load increase in area 1, area 1 picks up 33.33 MW and area 2 picks up 66.67 MW of generation. The 66.67-MW increase in area 2

(*Continued*)

generation is transferred to area 1 through the tie-lines. Therefore, the change in net tie-line power flow out of each area is

$$\Delta p_{\text{tie2}} = +66.67 \quad \text{MW}$$
$$\Delta p_{\text{tie1}} = -66.67 \quad \text{MW}$$

b. From (12.3.1), the area control error for each area is

$$\text{ACE}_1 = \Delta p_{\text{tie1}} + \text{B}_1 \Delta f_1$$
$$\text{ACE}_2 = \Delta p_{\text{tie2}} + \text{B}_2 \Delta f_2$$

Neglecting losses, the sum of the net tie-line flows must be zero; that is, $\Delta p_{\text{tie1}} + \Delta p_{\text{tie2}} = 0$ or $\Delta p_{\text{tie2}} = -\Delta p_{\text{tie1}}$. Also, in steady-state $\Delta f_1 = \Delta f_2 = \Delta f$.

Using these relations in the above equations,

$$\text{ACE}_1 = \Delta p_{\text{tie1}} + \text{B}_1 \Delta f$$
$$\text{ACE}_2 = -\Delta p_{\text{tie1}} + \text{B}_2 \Delta f$$

In steady-state, $\text{ACE}_1 = \text{ACE}_2 = 0$; otherwise, the LFC given by (12.3.2) would be changing the reference power settings of turbine-governors on LFC. Adding the above two equations,

$$\text{ACE}_1 + \text{ACE}_2 = 0 = (\text{B}_1 + \text{B}_2)\Delta f$$

Therefore, $\Delta f = 0$ and $\Delta p_{\text{tie1}} = \Delta p_{\text{tie2}} = 0$. That is, in steady-state the frequency error is returned to zero, area 1 picks up its own 100-MW load increase, and area 2 returns to its original operating condition—that is, the condition before the load increase occurred.

Note that the turbine-governor controls act almost instantaneously, subject only to the time delays shown in Figure 12.9. However, LFC acts more slowly. LFC raise and lower signals are dispatched from the area control center to turbine-governors at discrete time intervals of 2 or more seconds. Also, it takes time for the raise or lower signals to accumulate. Thus, case (a) represents the first action. Turbine-governors in both areas rapidly respond to the load increase in area 1 in order to stabilize the frequency drop. Case (b) represents the second action. As LFC signals are dispatched to turbine-governors, Δf and Δp_{tie} are slowly returned to zero.

The choice of the B_f and K_i constants in (12.3.1) and (12.3.2) affects the transient response to load changes—for example, the speed and stability of the response. The frequency bias B_f should be high enough such that each area adequately contributes to frequency control. Cohn [4] has shown that choosing B_f equal to the area frequency response characteristic, $\text{B}_f = \beta$, gives satisfactory performance of the interconnected system. The integrator gain K_i, should not be too high; otherwise, instability may result. Also, the time interval at which LFC signals are dispatched, 2 or more seconds, should be long enough so that LFC does not attempt to follow random or spurious load changes. A detailed investigation of the effect of B_f, K_i, and LFC time interval on the transient response of LFC and turbine-governor controls is beyond the scope of this text.

Two additional LFC objectives are to return the integral of frequency error and the integral of net tie-line error to zero in steady-state. By meeting these objectives, LFC controls both the time of clocks that are driven by 60-Hz motors and energy transfers out of each area. These two objectives are achieved by making temporary changes in the frequency schedule and tie-line schedule in (12.3.1).

Finally, note that LFC maintains control during normal changes in load and frequency—that is, changes that are not too large. During emergencies, when large imbalances between generation and load occur, LFC is bypassed and other, emergency controls are applied.

COORDINATION OF ECONOMIC DISPATCH WITH LFC

Both the load-frequency control (LFC) and economic dispatch objectives are achieved by adjusting the reference power settings of turbine-governors on control. Figure 12.13 shows an *automatic generation control* strategy for achieving both objectives in a coordinated manner. In this figure, P_{iD} is the desired output of each generator as computed from an economic dispatch program, which is discussed in

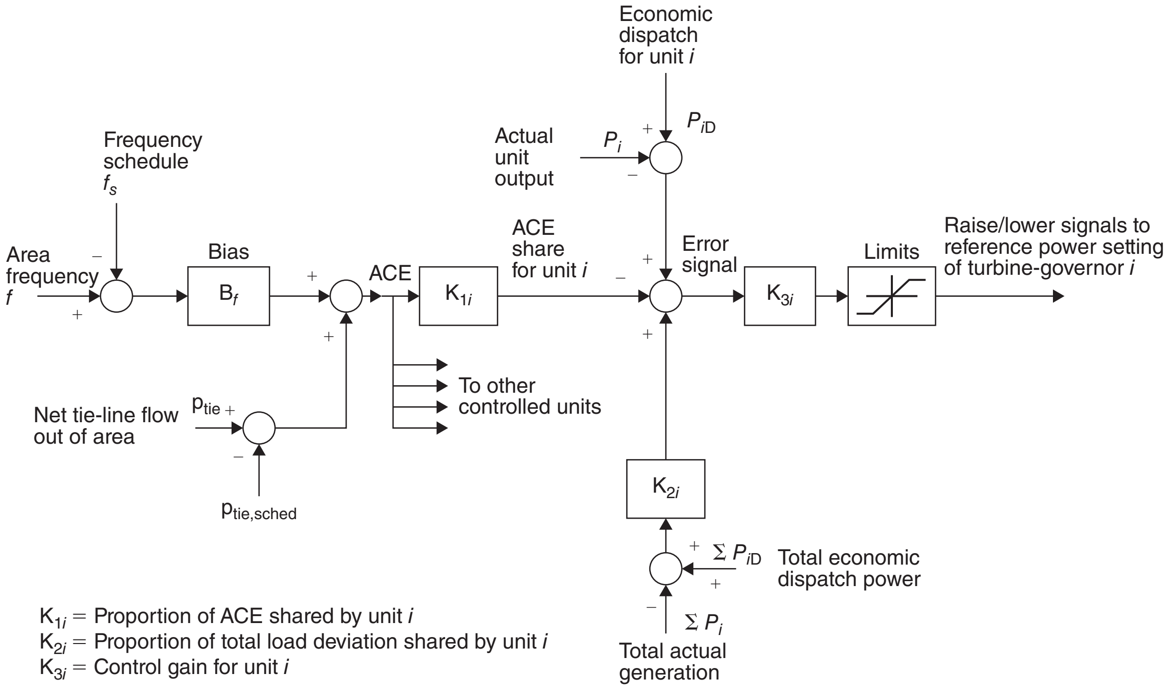


FIGURE 12.13

Automatic generation control [11] (Based on A.J. Wood and B.F. Wollenberg, Power Generation, Operation, and Control, 1989, John Wiley & Sons)

Section 6.12. As shown in Figure 12.13, the area control error (ACE) is first computed, and a share K_{1i} of the ACE is allocated to each unit. Second, the deviation of total actual generation from total desired generation is computed, and a share $K_{2i}\Sigma(P_{iD} - P_i)$ is allocated to unit i. Third, the deviation of actual generation from desired generation of unit i is computed, and $(P_{iD} - P_i)$ is allocated to unit i. An error signal formed from these three components and multiplied by a control gain K_{3i} determines the raise or lower signals that are sent to the turbine-governor of each unit i on control.

In practice, raise or lower signals are dispatched to the units at discrete time intervals of 2 to 10 seconds. The desired outputs P_{iD} of units on control, determined from the economic dispatch program, are updated at slower intervals, typically every 2 to 10 minutes.

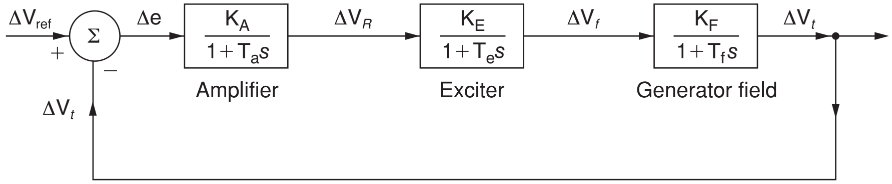
PROBLEMS

SECTION 12.1

12.1 The block-diagram representation of a closed-loop automatic regulating system, in which generator voltage control is accomplished by controlling the exciter voltage, is shown in Figure 12.14. T_a, T_e, and T_f are the time constants associated with the amplifier, exciter, and generator field circuit, respectively. (a) Find the open-loop transfer function G(s). (b) Evaluate the minimum open-loop gain such that the steady-state error Δe_{ss} does not exceed 1%. (c) Discuss the nature of the dynamic response of the system to a step change in the reference input voltage.

FIGURE 12.14

Problem 12.1



12.2 The Automatic Voltage Regulator (AVR) system of a generator is represented by the simplified block diagram shown in Figure 12.15, in which the sensor is modeled by a simple first-order transfer function. The voltage is sensed through a voltage transformer and then rectified through a bridge rectifier. Parameters of the AVR system are given as follows.

	Gain	Time Constant (seconds)
Amplifier	K_A	$T_A = 0.1$
Exciter	$K_E = 1$	$T_E = 0.4$
Generator	$K_G = 1$	$T_G = 1.0$
Sensor	$K_R = 1$	$T_R = 0.05$

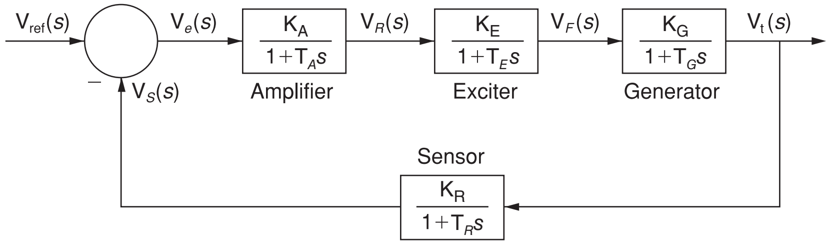


FIGURE 12.15

Problem 12.2

(a) Determine the open-loop transfer function of the block diagram and the closed-loop transfer function relating the generator terminal voltage $V_t(s)$ to the reference voltage $V_{ref}(s)$. (b) For the range of K_A from 0 to 12.16, comment on the stability of the system. (c) For $K_A = 10$, evaluate the steady-state step response and steady-state error.

PW **12.3** Open PowerWorld Simulator case Problem 12_3. This case models the system from Example 12.1 except with the rate feedback gain constant, K_f, has been set to zero and the simulation end time was increased to 30 seconds. Without rate feedback the system voltage response will become unstable if the amplifier gain, K_a, becomes too large. In the simulation this instability will be indicated by undamped oscillations in the terminal voltage (because of the limits on V_r the response does not grow to infinity but rather bounces between the limits). Using transient stability simulations, iteratively determine the approximate value of K_a at which the system becomes unstable. The value of K_a can be on the **Generator Information Dialog, Stability, Exciters** page.

PW **12.4** One of the disadvantages of the IEEET1 exciter is following a fault the terminal voltage does not necessarily return to its prefault value. Using PowerWorld Simulator case Problem 12_3 determine the prefault bus 4 terminal voltage and field voltage. Then use the simulation to determine the final, postfault values for these fields for $K_a = 100$, 200, 50, and 10. Referring to Figure 12.3, what is the relationship between the reference voltage, and the steady-state terminal voltage and the field voltage?

SECTION 12.2

12.5 An area of an interconnected 60-Hz power system has three turbine-generator units rated 200, 300, and 500 MVA. The regulation constants of the units are 0.03, 0.04, and 0.05 per unit, respectively, based on their ratings. Each unit is initially operating at one-half its own rating when the load suddenly decreases by 150 MW. Determine (a) the unit area frequency response characteristic β on a 100-MVA base, (b) the steady-state increase in area frequency, and (c) the MW decrease in mechanical power output of each turbine. Assume that the reference power setting of each turbine-governor remains constant. Neglect losses and the dependence of load on frequency.

12.6 Each unit in Problem 12.5 is initially operating at one-half its own rating when the load suddenly increases by 100 MW. Determine (a) the steady-state decrease in area frequency, and (b) the MW increase in mechanical power output of each turbine. Assume that the reference power setting of each turbine-generator remains constant. Neglect losses and the dependence of load on frequency.

12.7 Each unit in Problem 12.5 is initially operating at one-half its own rating when the frequency increases by 0.005 per unit. Determine the MW decrease of each unit. The reference power setting of each turbine-governor is fixed. Neglect losses and the dependence of load on frequency.

12.8 Repeat Problem 12.7 if the frequency decreases by 0.005 per unit. Determine the MW increase of each unit.

12.9 An interconnected 60-Hz power system consisting of one area has two turbine-generator units, rated 500 and 750 MVA, with regulation constants of 0.04 and 0.06 per unit, respectively, based on their respective ratings. When each unit carries a 300-MVA steady-state load, let the area load suddenly increase by 250 MVA. (a) Compute the area frequency response characteristic β on a 1000-MVA base. (b) Calculate Δf in per-unit on a 60-Hz base and in Hz.

PW **12.10** Open PowerWorld Simulator case Problem 12_10. The case models the system from Example 12.4 except 1) the load increases is a 50% rise at bus 6 for a total increase of 250 MW (from 500 MW to 750 MW), 2) the value of R for generator 1 is changed from 0.05 to 0.04 per unit. Repeat Example 12.4 using these modified values.

PW **12.11** Open PowerWorld Simulator case Problem 12_11, which includes a transient stability representation of the system from Example 6.13. Each generator is modeled using a two-axis machine model, an IEEE Type 1 exciter and a TGOV1 governor with R = 0.04 per unit (a summary of the generator models is available by selecting either **Stability Case Info, Transient Stability Generator Summary** which includes the generator MVA base, or **Stability Case Info, Transient Stability Case Summary**). The contingency is the loss of the generator at bus PEAR69, which initially has 65 MW of generation. Analytically determine the steady-state frequency error in Hz following this contingency. Use PowerWorld Simulator to confirm this result; also determine the magnitude and time of the largest bus frequency deviation.

PW **12.12** Repeat Problem 12.11 except first double the H value for each of the machines. This can be most easily accomplished by selecting **Stability Case Info, Transient Stability Case Summary** to view the summary form. Right click on the line corresponding to the Machine Model class, and then select Show Dialog to view an editable form of the model parameters. Compare the magnitude and time of the largest bus frequency deviations between Problem 12.12 and 12.11.

12.13 For a large, 60 Hz, interconnected electrical system assume that following the loss of two 1400 MW generators (for a total generation loss of 2800 MW) the change in frequency is -0.12 Hz. If all the on-line generators that are available to participate in frequency regulation have an R of 0.04 per unit (on their own MVA base), estimate the total MVA rating of these units.

SECTION 12.3

12.14 A 60-Hz power system consists of two interconnected areas. Area 1 has 1200 MW of generation and an area frequency response characteristic $\beta_1 = 400$ MW/Hz. Area 2 has 1800 MW of generation and $\beta_2 =$ 600 MW/Hz. Each area is initially operating at one-half its total generation, at $\Delta p_{\text{tie}1} = \Delta p_{\text{tie}2} = 0$ and at 60 Hz, when the load in area 1 suddenly increases by 400 MW. Determine the steady-state frequency error and the steady-state tie-line error Δp_{tie} of each area. Assume that the reference power settings of all turbine-governors are fixed. That is, LFC is not employed in any area. Neglect losses and the dependence of load on frequency.

12.15 Repeat Problem 12.14 if LFC is employed in area 2 alone. The area 2 frequency bias coefficient is set at $B_{f2} = \beta_2 = 600$ MW/Hz. Assume that LFC in area 1 is inoperative due to a computer failure.

12.16 Repeat Problem 12.14 if LFC is employed in both areas. The frequency bias coefficients are $B_{f1} = \beta_1 = 400$ MW/Hz and $B_{f2} = \beta_2 = 600$ MW/Hz.

12.17 Rework Problems 12.15 through 12.16 when the load in area 2 suddenly decreases by 300 MW. The load in area 1 does not change.

12.18 On a 1000-MVA common base, a two-area system interconnected by a tie line has the following parameters:

Area	1	2
Area Frequency Response Characteristic	$\beta_1 = 0.05$ per unit	$\beta_2 = 0.0625$ per unit
Frequency-Dependent Load Coefficient	$D_1 = 0.6$ per unit	$D_2 = 0.9$ per unit
Base Power	1000 MVA	1000 MVA
Governor Time Constant	$\tau_{g1} = 0.25$ s	$\tau_{g2} = 0.3$ s
Turbine Time Constant	$\tau_{t1} = 0.5$ s	$\tau_{t2} = 0.6$ s

The two areas are operating in parallel at the nominal frequency of 60 Hz. The areas are initially operating in steady state with each area supplying 1000 MW when a sudden load change of 187.5 MW occurs in area 1. Compute the new steady-state frequency and change in tie-line power flow (a) without LFC, and (b) with LFC.

CASE STUDY QUESTIONS

a. As a result of the August 14, 2003 blackout in North America, what major electrical islands were formed?

b. What is the first step in restoration?

c. What lessons were learned from this blackout?

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