Dynamic Positioning Power Plant System Reliability and Design

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DYNAMIC POSITIONING POWER PLANT SYSTEM RELIABILITY AND DESIGN

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Abstract—Power plant reliability is critical for the operation of dynamic positioning vessels. There are several common-mode failures of the engine, synchronous machine, governor, and exciter system that can cause a complete blackout of the on-board power system and millions of dollars in revenue loss.

Closed bus-tie operation of power plants provides superior tolerance for dynamic positioning power plant faults. However, a vessel operating with closed bus-tie breakers is not guaranteed to retain thrusters during certain types of power system failures. In these situations, rapid recovery of equipment is critical for meeting the minimum requirements of station keeping. Open bus ties are often used when rapid recovery is inadequate to meet operational needs and retention of thrusters is necessary. Operating with open bus ties reduces overall power plant reliability but maintains the availability of thrusters during any equipment fault. This paper presents a design that provides the desired reliability of closed bus-tie operation, while providing nearly the same thruster retention capability as open bus-tie operation. Using advanced fault detection and plant management techniques, faults that typically result in the loss of all thrusters on a closed bus-tie power plant can be handled such that sufficient thrusters remain operational to continue dynamic positioning operation, even after the fault.

This paper explains several critical protection areas for offshore vessel failure modes currently affecting these vessels and concludes with a design discussion of the latest technology in the area of protection and control.

Index Terms—Offshore vessel, power management system, load shedding, common-mode failure, advanced generator protection, automatic transfer, synchrophasor, real-time digital simulations.

I. HISTORY OF OFFSHORE PLATFORMS

An offshore platform, often referred to as an oil platform or oil rig, houses the workers and machinery needed to drill wells in ocean beds to extract oil, natural gas, or both.

Built in 1970, the first purpose-built dynamic positioning (DP) drilling vessel, SEDCO 445, had seven diesel electric generators in two engine rooms that provided 14 MW of power on one bus. Propulsion was provided by 24 dc motors driving 14 propellers. The power management system (PMS) consisted of a marine engineer sitting in the engine control room to monitor loads and start more engines, as required.

By 1980, automation systems had advanced to the point where all new DP vessels had PMSs that could automatically start and stop the main engines and phase back or otherwise limit loads to prevent blackouts.

Today, DP vessel power plants are delivered with four to eight generators powering two or three main buses. The most common configuration has six generators supplying two buses. Modern PMSs are complex and sophisticated, with multiple levels of protection, from dedicated protective devices on individual generators to load-limiting and engine management software in the supervisory automation system. Modern computer technology makes it possible to design generator management and protection schemes that seemed like science fiction just a few years ago.

II. TYPICAL OFFSHORE PLATFORM AND PROTECTION SYSTEM

Fig. 1 shows a typical DP offshore system one-line diagram of a power plant on an ultra-deep-water drilling vessel. In this example, the vessel has six main generators rated at 5,375 kVA each, six to eight bow or stern thrusters rated at 5,000 hp (approximately 3,730 kW) each, and variable frequency drives (VFDs) to operate the system. There are two main 11 kV buses connected via the bus-tie breakers that are sometimes operated normally open. Grounding transformers are provided at both main 11 kV buses. Each 11 kV main bus supplies power to a 600 V bus for drilling.

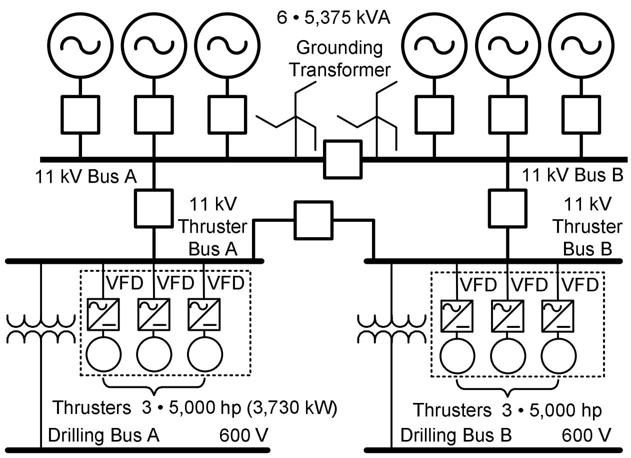


Fig. 1 Example DP Offshore System

The thrusters can have dual feeds that draw power from both buses. The 11 kV bus is a radial bus with a bus-tie breaker. The bus is fully insulated to provide protection against short circuits. Offshore platforms can vary in voltage from 4.16 to 13.8 kV. As the size of power plants is growing and expected to grow close to 100 MW [1], other configurations, such as ring and breaker-and-a-half, will require investigation to improve the system reliability.

III. DP VESSEL EQUIPMENT CLASS

A DP vessel is a unit or vessel that automatically maintains its position (fixed location or predetermined track) exclusively by means of thruster force and includes components such as power systems, thrusters, and DP control systems. The maritime industry accepts the definitions of DP system reliability as specified by the Maritime Safety Committee (MSC) of the International Maritime Organization (IMO). MSC Circular 645 *Guidelines for Vessels With Dynamic Positioning Systems* specifies a DP system and DP system reliability, as follows:

> A DP system consists of components and systems acting together to achieve a sufficiently reliable position-keeping capability. The necessary reliability is determined by the consequence of a loss of position-keeping capability. [2]

IMO specifies three levels of equipment class redundancy, defined by the worst-case failure. IMO does not specify a particular equipment class requirement for any particular operation or a measurable level of reliability. Instead, IMO recommends that the vessel owner and client agree on the level of redundancy that will meet the anticipated risk. Alternately, coastal states or federal administrations may require a particular equipment redundancy class for a particular operation. The equipment classes, as defined by IMO, are as follows:

- Equipment Class 1: loss of position may occur after the loss of a single component.
- Equipment Class 2: loss of position is not to occur in the event of a single fault in any active component or system. Single-failure criteria include the following:
  - Any active component or system (i.e., generator, thruster, switchboard, or remote-controlled valve).
  - Any normally static component (i.e., cable, pipe, or manual valve) that is not properly documented with respect to protection and reliability.
  - Any reasonably probable single inadvertent act.
- Equipment Class 3: same as Equipment Class 2, except a single failure is further defined as follows:
  - Items included in Equipment Class 2 and any normally static component are assumed to fail.
  - All components are in a watertight compartment, protected from fire or flooding.

It is worth noting that no specific reliability or operating criterion is defined by MSC Circular 645. Equipment redundancy does not necessarily provide reliability. Also, the IMO DP equipment class specifically avoids defining operating modes, allowing the vessel owner, client, and coastal authorities to assess which level of equipment redundancy (IMO DP equipment class) best achieves the desired reliability requirements for any given operation.

This paper proposes a design that directly addresses increasing reliability, without changing either redundancy or IMO DP equipment class. This design also provides measureable fault recovery criteria that can be used to aid risk assessment and management and, thus, determination of acceptable operating limits.

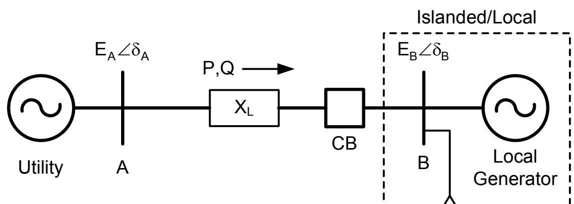
IV. DP POWER SYSTEMS

Although protection and control systems have dramatically changed since 1970, the rotating machines (diesels and generators) that make up the power plant have not changed significantly since then. The most common failures of the main power plant are essentially the same in 2010 as in 1970. However, the reliability of protection and control systems, including switchgear, has improved greatly.

Historically, more than half of all DP incidents are caused by or involve the power plant. More significantly, DP incidents that involve the power plant tend to be more expensive than other DP incidents because DP incidents related to the power plant typically interrupt DP operation and drilling operation. This results in lost revenue while the problem is corrected. Even an event that does not interrupt drilling operation normally has an associated cost while the problem is investigated and mitigations are implemented to reduce or eliminate future events.

Because the design of the rotating machinery is essentially static, the only opportunity to improve reliability is via enhancement of the protection and recovery systems, reducing the frequency, duration, and significance of power plant faults and failures. Furthermore, if a high degree of understanding and confidence can be established, relatively rare events will no longer require extensive investigation.

DP power plant systems are different than utility power systems, which consist of many generators and transmission lines, shown as the utility source and transmission line (X_L) in Fig. 2. The local generation and load are small compared with the utility. However, in the case of DP offshore vessels, the power system consists of local generation and load only. This type of power system is defined as an islanded power system when there is no connection to the utility or grid and local generation is the only power source for loads.



$$P = \frac{E_A \bullet E_B}{X_L} \bullet \sin(\delta_A - \delta_B)$$

$$Q = \frac{E_B}{X_L} \bullet \left[E_A \bullet \cos(\delta_A - \delta_B) - E_B\right]$$

Fig. 2 Simplified Utility Power System

For the utility power system, the power flow between the local and utility sources depends upon the angle between the two systems and the line impedance, as shown in Fig. 2. Fig. 3 shows that, as load increases, the power flow increases until the internal angle (δ) difference is 90 degrees (refer to the power flow curve). The utility system, as shown in Fig. 2, is more stable in comparison with the islanded system and rides through various system transient conditions because the larger inertia of a utility system is inherently stable for small disturbances. However, there may be local or interarea oscillations if the local generation is weak and connects via long lines or a weak network.

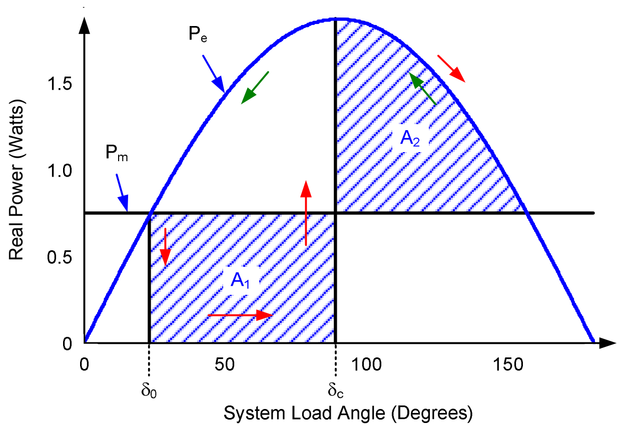


Fig. 3 Power Flow Example and Critical Clearing

Because DP offshore platforms are islanded power systems, the reliability of power plant operation is very important. A single outage can result in millions of dollars in revenue loss. For DP vessels, system inertia is relatively small, and even short system disturbances can result in the system becoming unstable. Detailed dynamic studies are required for various system configurations, and critical clearing time (CCT) should be determined. In some cases, special protection schemes are required to island the faulty section or shed load.

V. CLOSED BUS-TIE OPERATION AND MOTOR BUS TRANSFER

Closed bus-tie operation of power plants provides superior tolerance to DP power plant faults. However, a vessel operating with closed bus-tie breakers is not guaranteed to retain thrusters during certain types of power system failures. The proposed solution discusses DP vessels with a normally closed bus-tie breaker. The critical load on DP vessels is the thruster load. High-speed bus protection detects the fault and islands the faulty bus section in less than 5 cycles, including the breaker operating time. For a fault in any other section or equipment, the respective protection islands the system as soon as possible. However, it is possible that, depending upon the severity of the fault, critical loads (thrusters) may drop out for the fault. Hence, to improve system reliability, it is required to reconnect and re-energize the thrusters as soon as possible in order to restore the system and critical loads. Section V and Section VI discuss various bus transfer schemes and a proposed solution for DP vessels.

Motor bus transfer (MBT) schemes are very popular for power plants. To maintain process continuity, motor buses may require transfer from a present source to a new source. The reasons for this may be fault clearing on the present source, deliberate transfer from a utility source to an on-site source during storm periods or for rate savings (and back to utility power at a later time), and de-energization of the present source for maintenance or construction. During the MBT schemes, electric motor-driven equipment decelerates because power sources are removed. The deceleration rate depends upon the inertia of the drives and the synchronizing power flowing between the motors due to trapped relative flux. As the motor decelerates, the relative angle between the power source and internal angle of the motor increases. The motor flux decay depends upon the load, motor time constant, and power flow between motors. The decay rate of internal voltage depends upon motor flux and motor speed, which are functions of load torque, moment of inertia, and real-power transfer between motors. If the relative angle is large at the time the breaker is closed, with significant flux and resultant voltage, an inrush that is larger than the normal inrush current may result. These high currents can cause high-winding forces and transient torques that damage rotating equipment.

Motors with adjustable speed drives (ASDs) have different characteristics during the high-speed bus transfer compared with motors without ASDs. Large ASDs typically have dc links, source-side converters, and motor-side inverters. Because of the pseudo isolation created by the dc links, the drive system machines are not connected synchronously to the rest of the system. ASD machines are not usually subjected to severe transient torque as a result of the transfer; however, a detailed transient study should be performed to verify the design of the fast transfer scheme.

The transfer schemes are categorized as follows:

- Parallel or closed circuit
- Fast simultaneous or fast sequential
- Residual or long time

A. Parallel or Closed-Circuit Transfer

In a parallel transfer, the new source is connected to the motor bus before the old source is tripped. The intent is to transfer sources without interruption. The phase angle and voltages from the motor bus and the new source are evaluated prior to the transfer to ensure that the motor bus and the new source are in synchronism or the new source lags or leads the old source by an acceptable angle. This method is widely acceptable for routine source transfers because transients on the motor bus are eliminated. If the two sources are not derived from the same primary source and a large-standing phase angle is present between them, the opportunity for a hot parallel transfer is eliminated.

Assuming the two-source phase angle relationship is acceptable and two sources are paralleled, currents flowing into and through the bus may violate the interrupt rating for the circuit breakers and the short-term withstand ratings of the source transformers. A fault occurring either on the bus or on one of the sources when the sources are paralleled can overstress the components of the bus system. The switchgear should be rated for closed-bus transfer if the operation mode requires this operating scenario.

B. Fast Simultaneous or Fast Sequential Transfer

In a fast simultaneous transfer, a trip command is issued to the present source breaker, and a close command is issued to the new source breaker at the same instant. The phase angle and voltages from the motor bus and the new source are evaluated prior to the transfer to ensure that the motor bus and the new source are in synchronism or the new source lags or leads the old source by an acceptable angle. The close command is unsupervised. This is the fastest transfer type that does not parallel the sources.

In a fast sequential transfer, the present source is tripped, and as soon as the present source breaker has started to open (typically indicated by an “early b” contact), a close command is issued to the new source breaker [3]. The close command may be supervised or unsupervised, depending on the transfer method employed.

In order to make a rapid blocking decision, specialized synchronism-check equipment should be employed to make decisions on a moving phase angle in the shortest time possible, typically 1 to 2 cycles. If the synchronism-check equipment reacts too slowly, a transfer could be allowed when the phase angle value is actually in violation of the settings. An unsupervised fast sequential transfer is faster than a supervised sequential transfer because the supervised transfer process must include a small delay to allow synchronism-check measurement and possible transfer blocking to occur.

C. Residual or Long-Time Transfer

In a residual transfer, the motor bus is connected to the new source after the voltage on the coasting motor bus falls to less than 0.25 pu. In this manner, regardless of the phase angle value, the resultant volts per hertz (V/Hz) will not exceed 1.33 [4].

In a long-time transfer, the motor bus is connected to the new source after a time delay that reflects that the voltage on the coasting motor bus has fallen to less than 0.25 pu.

This transfer type may not be fast enough to maintain process continuity because certain motor loads that cause rapid stalling may necessitate a restart of the motors on the bus.

VI. PROPOSED SOLUTION

Fig. 4 shows a conceptual block diagram for a DP offshore PMS protection scheme. The proposed scheme is dual redundant, and two independent sets of local protection are included to improve system reliability [5]. Generator protection is included in the local protection block, which communicates with the generator control block. Local protection devices communicate via direct fiber relay to relay or via IEC 61850 protocol using Ethernet in the system protection block. System Protection 1 and System Protection 2 are the hubs of all the decisions for PMS control and data exchange. The system protection processes all of the relevant information from local protection and provides control and decisions for the PMS. By properly collecting, manipulating, and presenting power system data as usable information, the system enables operation, maintenance, and engineering staff to diagnose system events, predict equipment failures, and minimize unnecessary maintenance. The proposed solution also guides operators in making decisions, such as controlling black start, manual override, and load shedding. The solution includes a human-machine interface (HMI) screen for system overview and control.

The fast sequential transfer scheme is proposed for DP vessels using high-speed breakers and technology to minimize deceleration to a level that limits the motor inrush current to an acceptable level. Because the bus-tie breaker is operated in the closed position, 11 kV Bus A and Bus B have the same angle (see Fig. 1). Considering the scenario that the fault occurred in Bus Section B, protection operates and islands Bus B for this fault in 3 to 5 cycles. It is quite possible that thruster motors also drop for this fault or VFD operation is blocked due to the VFD algorithm. A stability study determines a three-phase bus fault CCT [6]. If generators can withstand a 3- to 5-cycle, three-phase bus fault, the generators can run for this fault and re-energize the thrusters using the high-speed bus transfer.

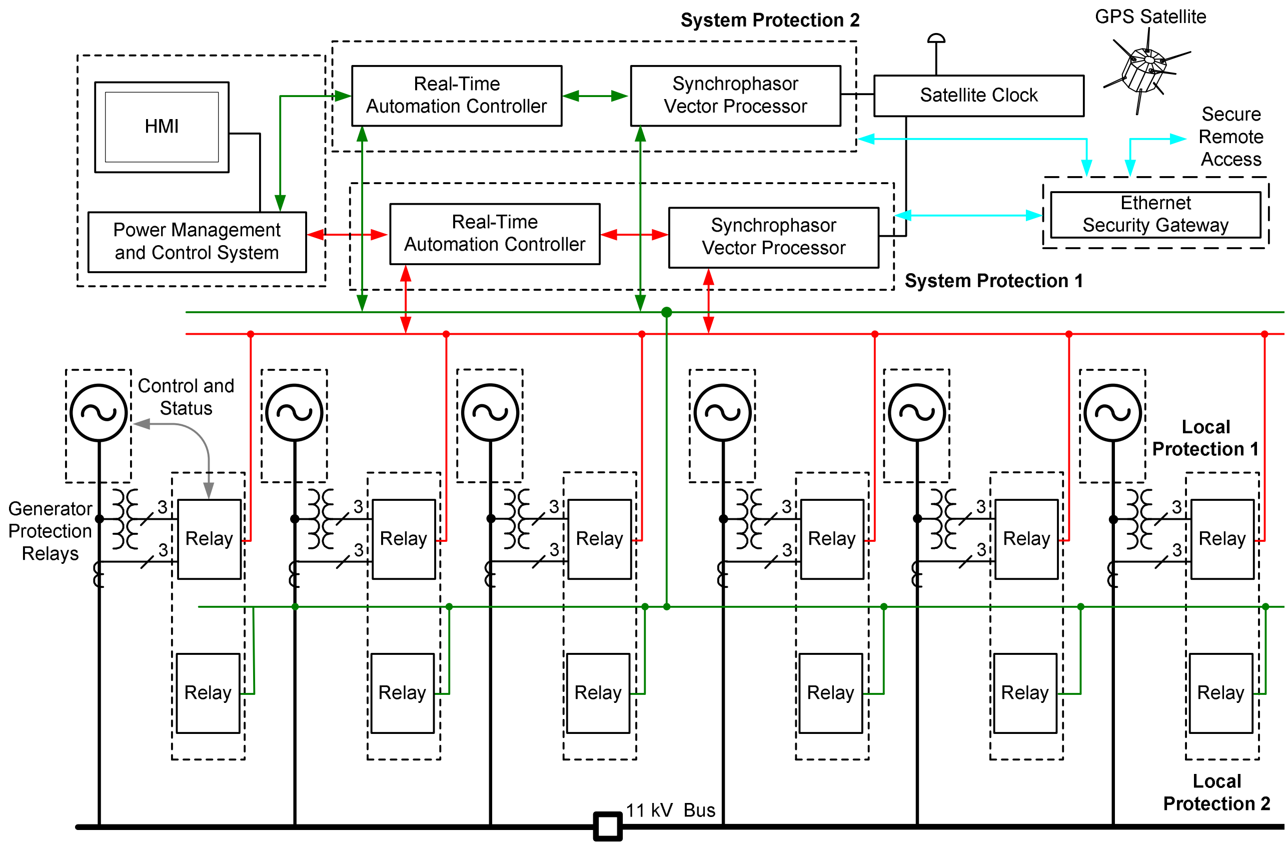


Fig. 4 Proposed Solution: Redundant Protection

Synchrophasor technology is also applied to detect the system conditions and decide the appropriate closing conditions. The protection system includes voltage and angle of both systems (E_S and E_M in Fig. 5). Using the slip calculations, an appropriate command to re-energize the islanded thruster can be issued for a direct online (DOL) motor start. Fig. 5 shows the importance of the correct closing angle in order to perform a successful transfer.

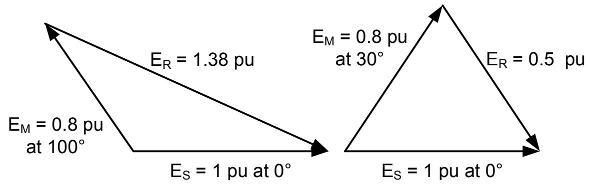


Fig. 5 High-Speed Motor Transfer (Resultant Voltage)

In Fig. 5, E_S is the system equivalent V/Hz (system voltage in per unit of motor rated voltage divided by the system frequency in per unit of rated frequency). E_M is the motor residual V/Hz (motor terminal voltage in per unit of motor rated voltage divided by the motor speed in per unit of synchronous speed). E_R is the resultant vectorial voltage in per unit V/Hz on the motor-rated voltage and frequency base.

An important value used to decide the viability of MBT is the resultant V/Hz derived from the V/Hz vectors of the motor bus and the new source at the instant just prior to connection. This value should not exceed 1.33 V/Hz [4].

The local protection block includes generator protection relays. For the existing scheme, only one relay per generator is proposed. When redundancy is required, however, more than one generator protection relay is installed per generator. The proposed generator protection relay includes the protection elements shown in Fig. 6. The following optional generator protection elements can also be programmed:

- Field ground (64G)
- Compensator distance (21C)
- Out of step (78)

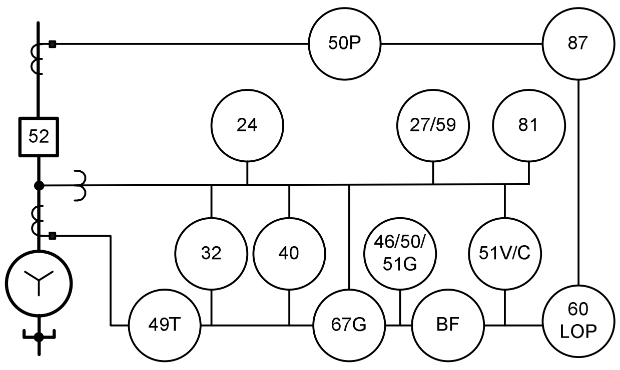


Fig. 6 Standard Features of Generator Protection Relay

The generator protection relay provides exciter and governor control for automatic synchronization.

VII. SYSTEM PROTECTION AND THE PMS

System protection provides the function of a data concentrator and includes all of the control for the PMS. Based on the overall DP system protection review, any additional protection, such as feeder, bus, motor, and transformer protection, is included as part of the system protection. The PMS also provides the following functions:

- Load-dependent start and stop
- Generator running order selection
- Load shedding
- Heavy-consumer start block
- Blackout start capability
- Diesel engine control

The PMS provides the control for generator start and stop based on the loads and priority of the generator to start the assigned units in the sequence, as required [7] [8]. Local generation can support 100 percent load during normal operation; however, during the outage of some units, a load-shedding scheme is enabled. Algorithms (i.e., priority loads to shed) must be designed into the system in order to react properly. The system remains operational and dynamically recalculates control set points under all system bus configurations. The PMS provides the control and start and stop of all generators.

The PMS includes protective relay front panels that automatically provide text and status point displays, which serve as a backup interface to the data acquisition and monitoring system. The relays are configured so the front-panel direct action pushbuttons operate as a backup control interface. The relay control interface includes a lock function to prevent accidental operation.

VIII. COMMUNICATION AND INTEGRATION TO THE PMS

Fig. 4 shows the complete system with communications and PMS integration. The proposed scheme uses fiber optics and peer-to-peer communication between various components. These communications are self-monitored. The user is automatically notified of any communications failure. Alternatively, the system can be designed using IEC 61850 protocol and Generic Object-Oriented Substation Event (GOOSE) messaging. As an option, systems can be designed using both IEC 61850 and peer-to-peer communication. The system protection block collects all of the information from the local protection block, and the correct sample rate is selected based on proper testing and design. Additionally, the proposed system is capable of providing a secure communications gateway via standard protocols, such as Modbus® and DNP3. Defense-in-depth strategies are employed for the security of the entire system. This strategy provides multiple layers of defensive mechanisms implanted in the products and the system as a whole (i.e., strong passwords and multilevel access) [9] [10].

IX. ENGINEERING DIAGNOSTICS AND ANALYSIS TOOLS

The proposed solution includes various built-in tools for system analysis and self-diagnostics. All of the relays and protection functions are self-monitoring and record any system discrepancy. Operators receive visual alarms. Using the PMS, the HMI continuously displays the operating parameters with alarm details. A separate screen is developed for each system component (i.e., one-line diagrams, alarms, and tools). The proposed system is programmed to send important information to key personnel for critical alarms.

The proposed PMS solution automatically collects event reports and Sequential Events Recorder (SER) data from all of the relays. SER reports generate comma-separated value (CSV) files with accurate satellite clock time stamps. The event reports and SER data are archived in the PMS. This information is used for the analysis of any system operation. Fig. 7 shows an example event report for a three-phase fault. For this fault, the phase angle, reverse overcurrent, and undervoltage protection operate and clear the fault.

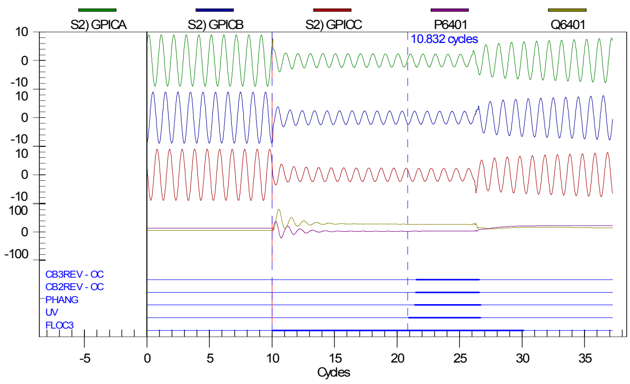


Fig. 7 Example Fault Analysis for a Three-Phase Fault

X. MEAN TIME BETWEEN FAILURES AND REDUNDANCY

Using the unavailability for each system component, fault trees are used to predict the overall system unavailability. Mean time to repair (MTTR) is the mean time to detect and repair a failure. We assume a worst-case MTTR number of 4 hours for the components in the proposed system. Some manufacturers measure the mean time to failure (MTTF) of all their in-service products. The mean time between failures (MTBF), expressed as MTBF = MTTR + MTTF, documents the failure rate from one manufacturer [11]. A review of the data shows that the likelihood of hardware component failure is very low. This type of information can be the foundation for maintenance and testing intervals. Table I lists the typical MTBF and unavailability for system components.

TABLE I
MTBF FOR PRODUCTS

Component	**Observed MTBF (years)**	**Unavailability (multiply by 10^{-6})**
Power management controllers and front-end processor	50	9.1
Programmable automation controller	150	3.0
Relays	300+	1.5
Ethernet switch	50	9.1

Generator protection philosophies that operate entirely at the generator level cannot detect external faults, such as main bus failure. Generator protection philosophies that operate at a higher, supervisory level may not detect individual generator faults or may not be able to determine the faulty generator in the case of common-mode faults. Combined systems using local and supervisory protection offer more comprehensive protection but may not be optimal because of the widely different scan rates of the two systems. However, a system designed upon synchrophasor data obtains the sampled data every cycle and generates control signals within 2 to 3 cycles. Considering the slower response time of exciters and the governor, this proposed system design is adequate.

XI. ADDITIONAL FEATURES

In addition to the functions of the PMS and generator protection, the proposed scheme includes the following features:

- Synchrophasors
- Feeder protection and arc-flash detection
- Transformer protection
- Bus protection
- Motor protection
- Common-mode generator protection

A. Synchrophasors

A definition of real-time (synchronized) phasors is provided in IEEE 1344-1995. Applying synchrophasors improves performance for critical applications. Each machine state is based on highly accurate Global Positioning System (GPS) satellite clock signals and synchrophasor data [12]. Fig. 8 shows the phasor measurement of multiple machines. An internal clock provides a signal in case the GPS signal fails. The logical comparison of synchrophasor variables is performed using system protection.

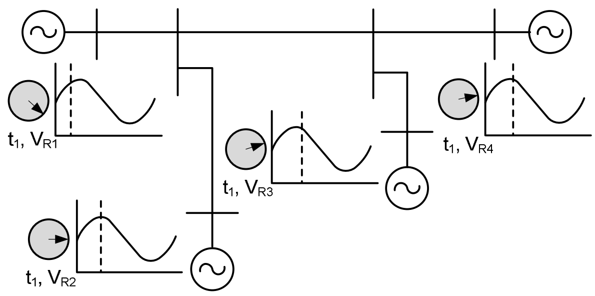


Fig. 8 Synchrophasor Measurement

Synchrophasors are applied to visualize the overall system performance with reference to the same time frame, and the data are automatically archived for future analysis. Using modal analysis (included in system protection), it is also possible to calculate the resonance and oscillation frequencies. This information is critical for advanced generator protection design. Existing DP vessel common-mode generator protection cannot detect the resonance and oscillation frequencies accurately.

B. Feeder Protection and Arc-Flash Detection

Arc-flash detection is important for the safety of the personnel working on a DP vessel. Fast, reliable operation of an arc-flash protective relay improves safety and reliability. The proposed solution provides feeder protection and arc-flash detection. Using advanced technology, faults are detected in 2 to 3 milliseconds, limiting the arc-flash damage to switchgear. Feeder protection and arc-flash detection are included in the same relay. The feeder relay includes the following protection functions:

- Phase and neutral overcurrent
- Under- and overvoltage
- Under- and overfrequency
- Breaker failure
- Arc-flash detection
- Rate of change of frequency (df/dt)

C. Other System Protection

Additional overall system protection, such as motor protection, bus protection, and transformer protection, is provided as part of this solution. The proposed solution uses the same relay for transformer and bus protection. The bus and transformer protective relay is capable of handling five three-phase current transformer (CT) inputs and three single-phase CT inputs for restricted earth fault (REF) protection. The proposed relay is based upon low-impedance bus protection. Low-impedance bus protection is faster at detecting a fault compared with high-impedance bus protection, in addition to other advantages [13]. A motor protection relay provides all of the protection functions required for the motor, including the thermal model.

Fig. 9 shows an example motor starting report [14]. In addition, one high-speed MBT relay is installed for each important motor. The MBT relay is the same as the bus and transformer protection relay. Selecting the same type of relay to protect pieces of equipment reduces the engineering and training time.

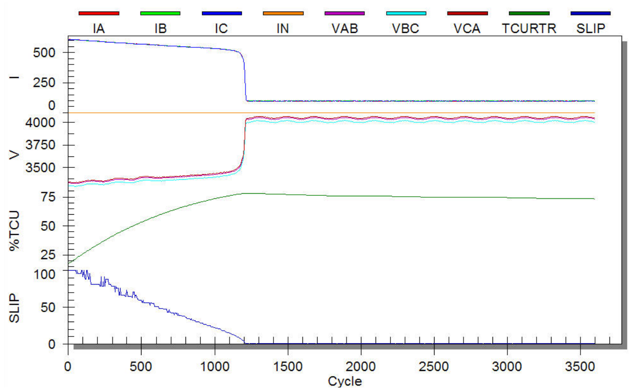


Fig. 9 Example Motor Starting Report

D. Common-Mode Faults

Common modes of failure are defined as faults that affect overall system operation and cause multiple redundant elements to react adversely. For normal operating conditions, all of the generators operate in parallel droop mode. In case of a fault on one generator exciter and governor or any other common-mode fault, it is desirable to properly detect and isolate only the faulty generator from the system as soon as possible [15]. It is also necessary to evaluate the response time of controls (e.g., exciter and governor controls) before making decisions regarding any system isolation or islanding. Otherwise, undesirable system operation may result in additional faults or failures. This solution correctly detects and islands for all common-mode faults, which are classified into the following categories:

- Governors
- Fuel or actuator
- Exciters
- Miscellaneous

Table II shows common-mode faults and possible solutions.

TABLE II
COMMON-MODE FAULTS AND SOLUTIONS

Fault	Description	Equipment
F1	Out-of-droop band	Governor
F2A	Actuator current low (actuator output low)	Actuator
F2B	Rack not tracking actuator (fuel rack problem)	Actuator
F2C	kW not tracking fuel rack (fuel problem)	Actuator
F2D	Fuel rack hunting (generator hunting)	Actuator
F3A	Overexcitation/underexcitation	Exciter
F3B	Unstable voltage control (hunting)	Exciter
F3C	Loss of exciter current	Exciter
F4A	Miscellaneous faults	Miscellaneous
F4B	Breaker status fail, kW > 0, and circuit breaker indication open	Miscellaneous
F4C	Breaker status close, f = 0, and generator running	Miscellaneous

When droop and no-load speed are set the same on all of the diesel engines, units that are electrically or mechanically tied together inherently share the load equally. Consistent droop results in a predictable speed for a given load on a generator based on a droop curve, the health of the connected diesel generator, and the speed control system. Deviation from this curve beyond an acceptable window is indicative of an unhealthy status in the engine (unable to deliver the required kilowatts) or a problem with the speed control system or its control system tuning parameters. These symptoms occur if there is a loss of engine power, such as a sticky injector, fuel pump failure, dirty fuel filter, incorrectly set ballhead governor, or limited fuel rack linkage movement. The power generated is below the level expected for the running speed, as determined from the established normal speed load curve for this engine. Hence, for the bus frequency of 60 Hz, the engine operates at less than 50 percent of full load. The other engines online are generating more power than they would have to if all generators were sharing equally; therefore, the speed is slightly lower than what would be expected for normal operation with that load.

Fig. 10 and Fig. 11 show the operation during the governor faults. Fig. 10 shows the slope and 3 percent droop characteristics for the generators operating in parallel. Curve A is selected if generators operate normally around 100 percent of load. Curve B is selected if the unit normally operates around 50 percent of load. For this analysis, Curve B is selected when normal operating load is 50 percent.

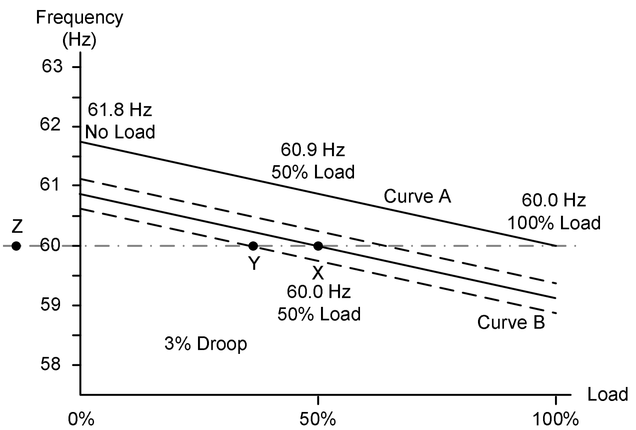


Fig. 10 Low Kilowatt and Droop Mode

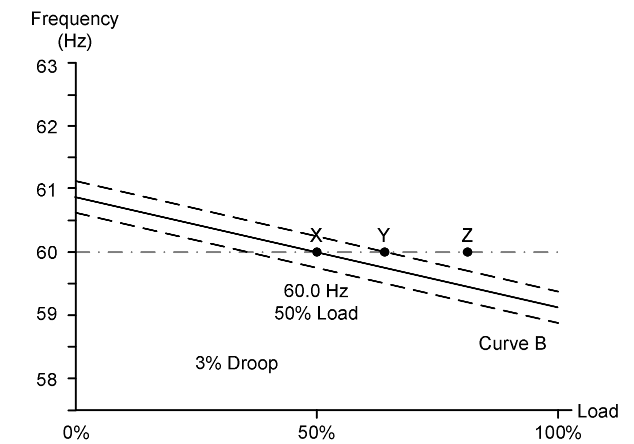


Fig. 11 High Kilowatt and Droop Mode

For a low-kilowatt fault (F1 fault), when one machine is generating, the Curve B generator operating point moves from X to Y, as shown in Fig. 10. For the operating point within the generator band, the control signal is only initiated for the faulty generator. However, if this generator goes outside the allowable band, system protection and the PMS start to island the faulty generator, and system load is shared by the rest of the machines. System frequency drops, and the PMS generates another control signal to correct the system frequency.

A high-kilowatt fault (F1 fault) may result from speed control feedback loss or actuator signal loss for a particular defective generator. This event results in producing more power than scheduled from this defective generator. This type of fault results in the remaining generators running lightly loaded. Fig. 11 illustrates that if the operating conditions for a generator change from X to Y, a control signal initiates for this generator. For this condition, system frequency increases. If this generator does not respond to the controls and drifts further to Z, a trip signal is initiated. Similar to the system condition for low-kilowatt conditions, the PMS generates a control signal to correct the system frequency. The generator voltage control system also runs in droop mode. When droop and no-load voltages are set the same on all the generators, these units inherently share the kvar equally. However, voltage control is more complex because it depends on the exciter controls. Exciter control can be initiated based on the system conditions, allowing system protection to monitor these operating conditions and provide information to the PMS. Because of faulty automatic voltage regulator electronics, low settings, or unstable voltage control, hunting is sensed via local protection (F3 faults). When a parallel generator is hunting, it periodically takes or sheds reactive power, resulting in hunting in the overall system. System protection identifies the generator with the faulty exciter and provides an alarm to the user to take corrective action. In the case of exciter loss of the current feedback because of a faulty exciter, the system generates another alarm. Hence, appropriate action is programmed based on the severity and acceptable operating conditions.

Some faults result because of the fuel rack position and actuator current (F2 faults). For this type of fault, when actuator current does not track the rack position, an alarm is generated. In the case of a generator fuel problem (damage to fuel line or fuel quality), generator output does not follow the generator fuel rack. Alarms are generated for the predetermined time, and subsequently, the unit is tripped because of the F1 fault. Fuel rack hunting may be caused by a number of problems, including dead bands in linkages, faulty speed-governor electronics, and faulty engine generator shaft coupling. The system protection block analyzes operating conditions and generates an alarm for the appropriate generator. The algorithm requires monitoring the generator parameters, including the fuel rack position for each generator.

For system fault conditions, such as breaker status open and generator kilowatt loss, an alarm is generated (F4 faults). This fault condition indicates that the system has lost the breaker status. For the system fault of breaker status close but a frequency indication of zero, an alarm is generated for the defective generator with some time delay. During this time, this generator is assumed to be operating properly, and if system disturbance continues beyond a predetermined time, the system protection islands the faulty generator, similar to an F1 fault. For miscellaneous system faults, such as any protective relay failure, the breaker contact failure to operate or any abnormal system condition is indicated as an alarm.

XII. OTHER CRITICAL ISSUES

The model power system testing laboratory is the proposed site for complete testing of systems using real-time simulation. Real-time simulation equipment allows dynamic modeling of a power system with a simulated small time step to test all closed-loop controls and protection systems [13]. The DP power system is modeled using real-time simulation, and system performance is benchmarked using the actual field results.

Fig. 12 shows an example of generator parameter verification using load shedding. The real-time simulation system study helps with relay settings and verifies the correct protection system operation of offshore vessels for system contingency conditions, system dynamics, and transient faults. This dynamic system model is utilized for the verification of PMS integration for black-start operation, load shedding, and fast MBT schemes. The system performance is also verified during field installation.

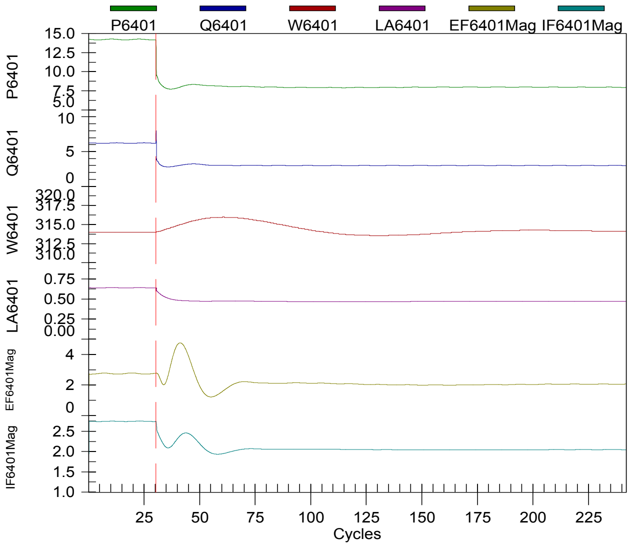


Fig. 12 Generator Results Benchmark Using Real-Time Simulation

XIII. DESIGN VERIFICATION

The PMS is designed and validated in the laboratory before it is deployed in the field. Critical systems, such as DP, require testing of the controllers and associated equipment during factory acceptance testing. These critical systems need to have their controls validated and tested in a real-time simulation environment. Using this type of validation and testing helps to accurately model governors, turbines, exciters, rotating machinery inertia, load and electrical characteristics, electrical component impedances, and magnetic saturation of electrical components.

Real-time simulation verifies the system design, protection settings, and overall system performance [16]. Thousands of faults and system disturbances are created and tested in a closed-loop system, evaluating the system performance even before the PMS is installed on site. In addition, the results of on-site testing are used to revalidate the system design. Once the standard DP system model is built, it can be easily applied for future system expansion and design variation. This tool has been used for various projects with complicated system designs, where settings are dependent on the system design parameters. Without detailed testing, selecting proper protection is not possible.

XIV. OFF THE SHELF AND COMPLETE

Fig. 4 shows the proposed system configuration. The system can be designed using redundant protection or single protection per generator. However, the incremental cost of additional protection is small in comparison to the overall project cost. System reliability is also improved by selecting redundant protection. The proposed design is easily expandable and can be applied to any type of offshore platform. For this example project, only six generators are installed; however, this system is easily expandable for vessels designed with more than six generators. As part of this engineering solution, a test bed serves as a valuable test lab for engineers to evaluate system performance. The proposed scheme can be a template for future designs and result in reduced engineering costs. Once the system is designed and tested for one vessel, the same design is easily applied to other vessels. The costs of training, maintenance, and system operation are also reduced because of the standard system design.

Detailed documentation and local support are best provided on location. Deep-water drilling platforms are located all over the world, so support and training for these critical projects are required “as needed” and “when needed.” The global presence of a support company is important to the acceptance and success of the project.

XV. CONCLUSION

This paper discusses the important features of the offshore vessel DP power plant, importance of power plant reliability, and conceptual design of protection, automation, and control using the latest technology available. It also discusses the advantages of operating the DP power plant as closed bus and a solution for a high-speed motor transfer scheme. This proposed solution provides cutting-edge protection functions for generators, using synchrophasor technology and the IEC 61850 protocol. In addition, the solution includes a PMS, arc-flash detection, and automatic synchronization. This solution is robust, easily expandable, condition monitoring, and self-diagnostic. It also provides automatic archiving of SER data and event reports. Using advanced technology and tools, a reliable PMS is designed and implemented. This paper also discusses the importance of detailed design verification using real-time simulation.

XVI. ACKNOWLEDGEMENT

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XVIII. VITAE

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Lew Weingarth received his BSEE from the University of Missouri-Rolla with honors in 1981, after which he worked for Southeastern Drilling Company as an engineer trainee. He is working toward an MBA. Until 2001, Lew worked in the offshore deep-water drilling industry, primarily on DP vessels. He then became an international consultant on DP and PMSs, working for oil companies and drilling contractors. In 2004, Lew accepted a position with Transocean as a DP superintendent for the purpose of assembling a discipline dedicated to eliminating DP and power system downtime.

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