7 Energy Management

7.1 Principles of Energy Management

Maintaining a reliable supply of electrical power to consumers is a highly complex process as most of this power cannot be stored and the individual components of this process, forming what is called a power system, can be spread over a wide geographical area. The purpose of power system management, also referred to as Energy Management, is to monitor, control and optimize this process in real-time. The basic functionality of power system control is found in the Supervisory Control and Data Acquisition (SCADA) function that collects and records values and statuses acquired from the power system elements via remote telemetry to enable control center operators to supervise and control the power system. Other decision support functions complement this function to provide power system management for a secure and optimal process (fig. 7.1-1).

7.1.1 The Role of the Network Control System in Power System Management

History

The control and information technology used for the management of a power system has its origins in the automation of power plants. The primary objective was then to improve operational reliability (fig. 7.1-2).

With the increasing number of power plants and their interconnection via the grid, primary frequency control, also referred to as generator droop control, was no longer sufficient. To improve on power delivery quality, coordination, including secondary frequency control, of power generation and, later, external interchange became unavoidable and was promptly implemented in control centers.

Before the introduction of the transistor in 1947, the vast majority of protection and control devices used in power system control were of electromechanical design. In the early days, information was transmitted by means of relays and pulse

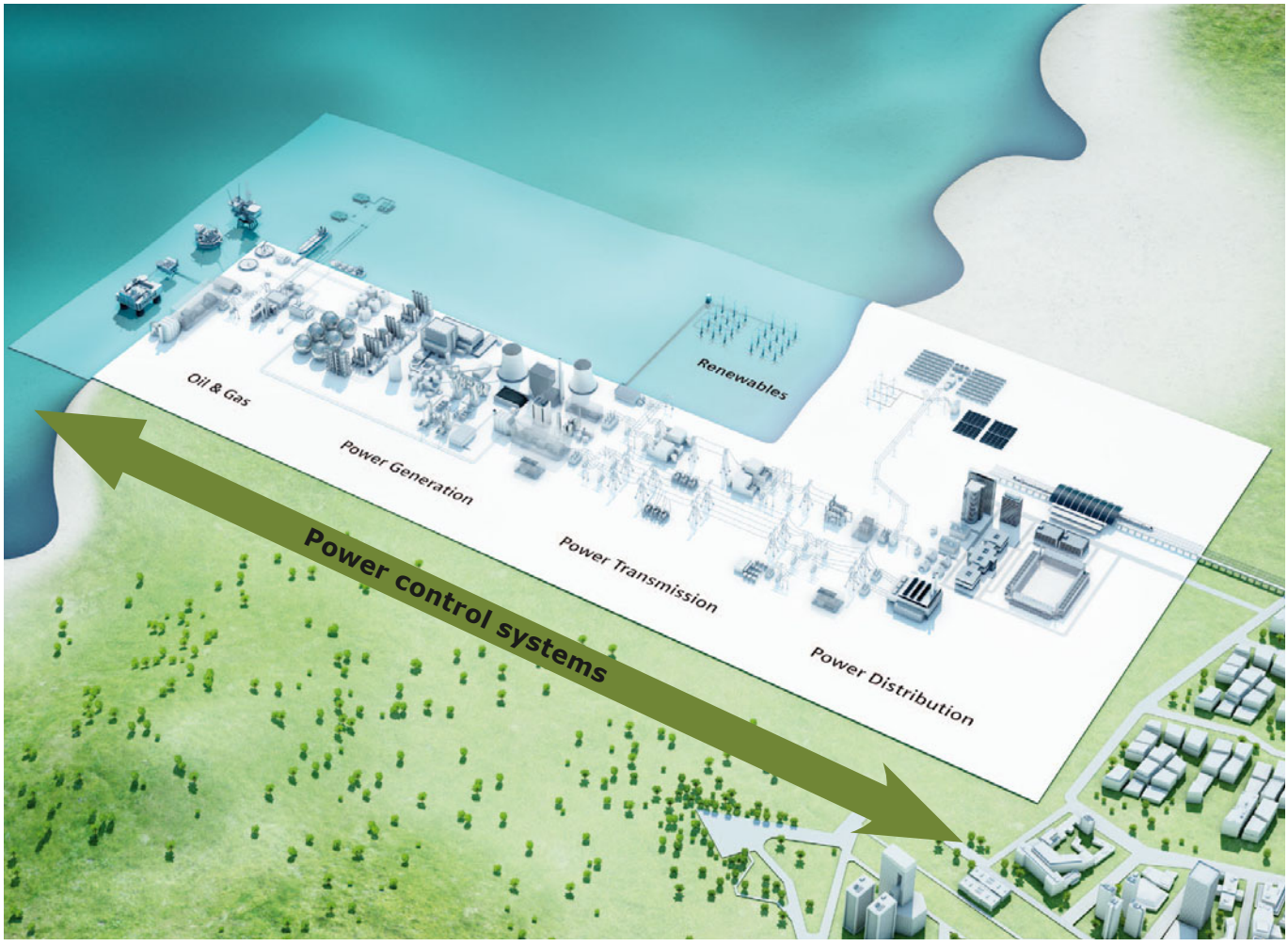


Fig. 7.1-1: **Power control systems – serving the complete energy chain from generation to load**

Fig. 7.1-2: **Todays' operator user interface of a large power control system**

techniques, but with the introduction of electronics it became possible to implement increasingly efficient transmission means. At the end of the 1960s, with the introduction of the first process control computer, the first computerassisted power and frequency control systems became possible.

As computers became more efficient in the 1970s, the switchgear in transmission networks was also gradually monitored and automated with the aid of power system control technology. In response to the growing demand for network control systems, a number of companies began developing standardized systems for these applications. The systems of that period can be called the first generation of network control systems.

Because of the inadequate graphics capability of computer terminals at that time, the master computers were used mainly for remote monitoring of unmanned stations or for performing calculations to support operations. The network state was displayed visually on large switch panels or mosaic walls that were also used to control the switchgear. Only as the performance of graphical displays improved were Operation management functions gradually transferred to VDU-based Workstations.

As computing power continued to increase in the mid-1970s, it also became possible to use computers for optimization processes. With the aid of optimization programs run initially as batch Jobs and later online as well, it was possible, for instance, to determine the most economical use of hydroelectric and thermal power plants. These programs also provided a method of economically assessing the exchange of energy, a basic requirement for energy trading later on. Increasing computer power was, however, also harnessed to further develop man-machine communication towards greater user friendliness.

In the mid-1980s, power system control, which had until then been restricted to transmission networks, was increasingly used in the distribution network area as well. Apart from pure network supervision, additional functions such as work or material administration were integrated into control systems during the ongoing automation of the distribution network.

Functions of a network control system

With the aid of network control systems, network operators can obtain information from the network, usually in real time, which they can then use as the basis for optimizing supervision and control of the power supply system (fig. 7.1-3).

The information transmitted by the station automation systems via telecontrol must be collected and processed at a central point. This function is performed by network control systems that are installed at central locations, which are also known as system control centers or control rooms.

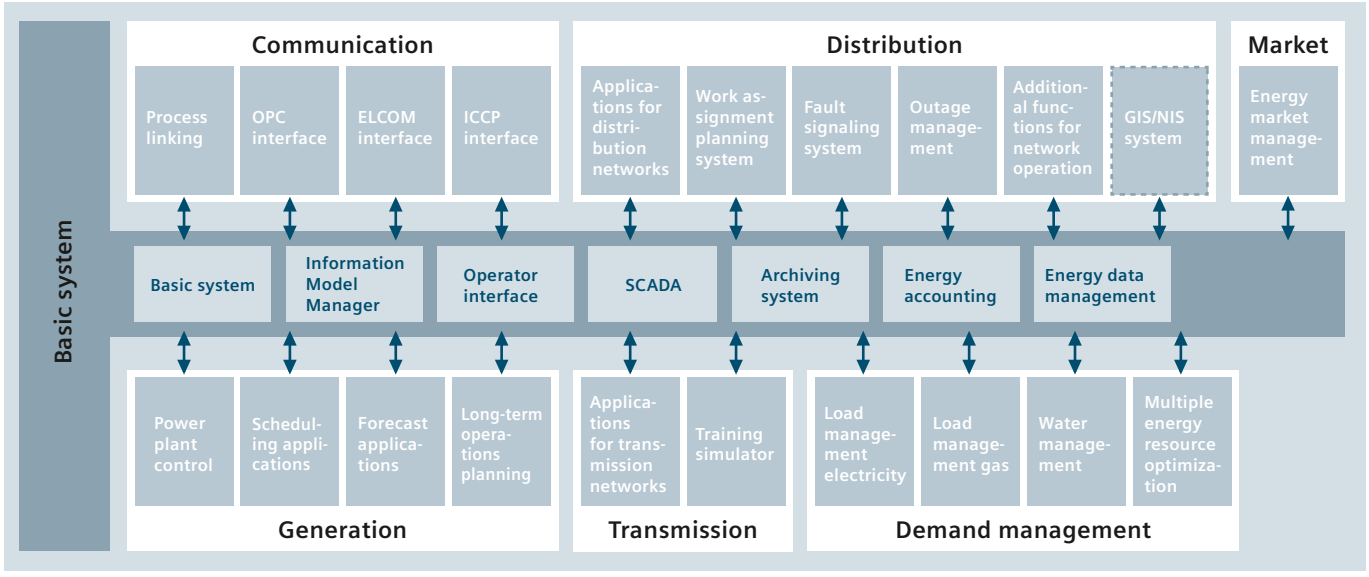


Fig. 7.1-3: **Power control system – components overview**

A distinction is made between Transmission Management Systems (TMS) and Distribution Management Systems (DMS) depending on the type of network being managed (transmission or distribution). Prior to deregulation, Energy Management Systems (EMS) were commonly used for the integrated management of generation and transmission. After deregulation, the unbundling of these two functions led to the creation of Generation Management Systems (GMS) for the independent management of the generating units.

All types of network control systems use the so-called SCADA system platform. Other applications may also use this platform. The most important application components of a network control system and their application areas.

Spectrum Power™ offers you a comprehensive range of functions for requirements in energy generation, network operations management and communications, including:

- Supervisory Control and Data Acquisition (SCADA).
- Data input and data modeling:
  - Data modeling compliant with IEC 61970 using the Common Information Model (CIM)
  - Powerful graphics editor
  - Parallel multi-station engineering with job management und undo functions
  - Powerful online data activation
- Extensive communications options with communcation protocols
- Maintenance and outage management:
  - Fault report handling
  - Planning and monitoring
  - Fault correction
- Functions for managing transmission networks:
  - State estimation
  - Load flow calculation or short circuit calculation
  - Contingency Analysis
- Functions for managing distribution networks:
  - Fault isolation and restoration of power
  - Load flow calculation
  - Short circuit calculation
  - Expert system
- Functions for energy data management
  - Schedule management
  - Forecasting
  - Archiving
  - Reporting
- Functions for demand side management
  - Load management for electricity and gas
  - Water supply management
- Functions for electric power producers
  - Automatic generation control with load frequency control
  - Scheduling applications

Real-time processing

SCADA applications are basic functions of the network control system and provide a means of supervising and controlling the power supply system. For this purpose, all information transmitted from the network is collected, preprocessed and visually displayed in order to keep the operator constantly informed about the current operating state of the power supply system. The operator can also store additional Information in the system or enter corrections for incorrectly reported Information or Information reported by phone into the system in order to complete the current operational network display (fig. 7.1-4).

The main objective of preprocessing is to relieve the operator of routine work and to supply the operator with essential Information. The most important preprocessing Steps to mention are limit value monitoring and alarm processing. These are absolutely essential, especially in the case of a fault incident, in order to enable the operator to identify the cause of the fault quickly and precisely and to take suitable countermeasures. The supply state of the network elements is shown in color (topological network coloring) in the process Images used for network monitoring in order to provide better visualization of the current network state. As a result, the operator can see at a glance which network sections are supplied and can identify any interruption in the supply at that particular moment.

Another important function performed by the SCADA applications is the so-called operational logbook, in which the process history is shown chronologically in plain text. Entries in the operational logbook can be triggered by events in the power supply system as well as by operator actions.

Switching measures in the power supply system, such as disconnecting and earthing a cable so that maintenance can be carried out without danger, generally require a sequence of individual commands. Because disconnection processes of this type have to be checked for plausibility in advance, a switching sequence management system in a control system can assist the operator in drawing up and testing the required switching sequences. During this process, the switching actions carried out in a simulation environment are recorded and can then be carried out partly or fully automatically after positive testing and in the real-time environment.

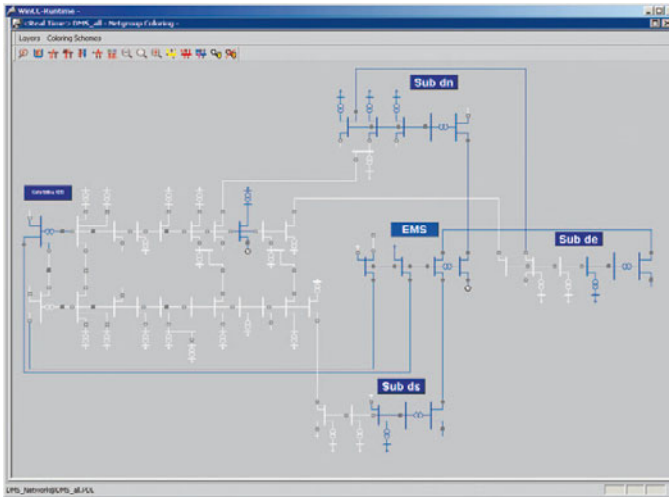


Fig. 7.1-4: **Example for a network diagram of a power grid**

Process data and control center communication
Process data from operational equipment is transferred and recorded directly from the process. There is often also an exchange of process data with other control centers. This exchange of information also has the purpose of enabling processes in the directly adjacent section of the network to be included in the network supervision and control process.

Today, the standardized IEC 870-5-101 and 104 protocols are increasingly used alongside old proprietary transmission protocols for transferring information from the local network. The OPC (OLE for Process Control) standard also offers a method of process communication and a means of communicating with the world of automation. The Inter-Control Center Communication Protocol (ICCP), also known as TASE2, has now become the established form of data exchange between control centers and is compliant with IEC standard 870-6.

Archiving
Another basic function of a control system is the processing of archive data. Archive data processing is responsible for cyclical collection, storage and aggregation. The archive allows different functions for data collection that group together and further process the data received from the real-time database. The resulting values are stored in turn in the archive. However, archives often also provide additional functions such as generating a sliding average or determining maximum and minimum values in order to process the real-time values before they are stored (fig. 7.1-5).

The calculation functions of an archive usually also comprise functions for implementing recurring calculations for time-dependent data. For example, the four fundamental operations can be used on measurement values. These calculations can be carried out at several levels, with the calculations at the lowest level being completed before the calculations at the next higher level are started. A typical application is the totaling of power generation in its entirety and per power plant type, or the balancing of energy consumption according to regions under different customer groups.

Load forecasting
In order to ensure a reliable power supply, a forecast of energy consumption (load) over time is required. Forecasting methods working on the basis of a regression approach, Kalman filtering or neural networks are used for medium-term planning in the range of up to one year (load planning). For the short term, i.e. in the range of up to one week, pattern-based approach is typically used with options to adjust for actual load values, for actual weather data, etc.

Power generation planning
A power producer company has typically a portfolio of different power plants available for generating electrical power. Power generation planning is made whilst economically optimizing the generation of the power needed according to the load forecast, market price forecast and contracts, taking into account the characteristics of the different power plants in the portfolio (fuel

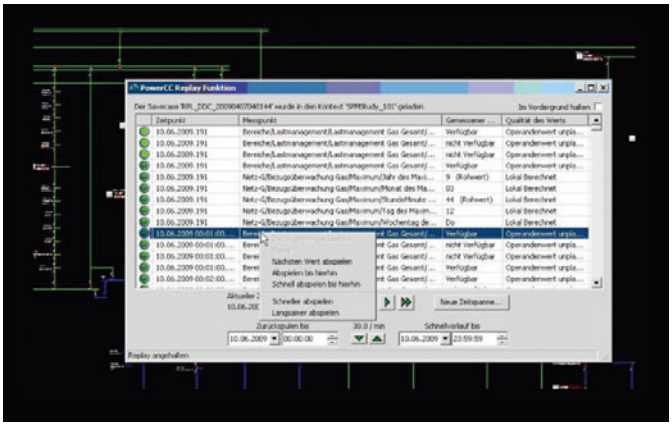


Fig. 7.1-5: **Operator user interface – replay of archived values in a network display**

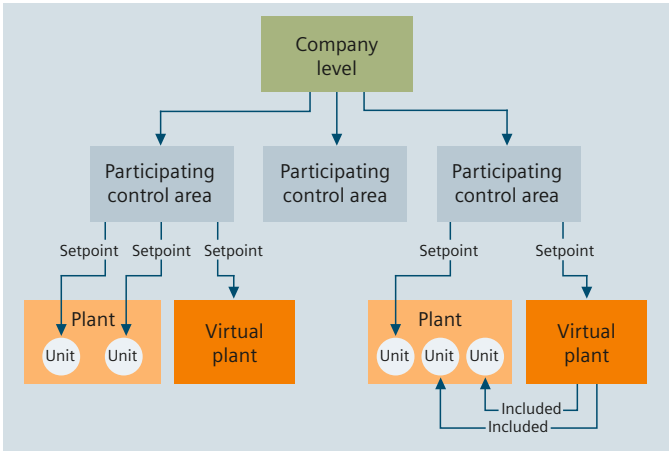


Fig. 7.1-6: **Concept of hierarchical control**

costs, start-up and shutdown times and costs, and rate of power change) to produce a generation timetable for all power generating units. These timetables are then used as target for power generation control (fig. 7.1-6).

Note that to meet its load the power producer may opt to buy additional energy
- from a 3rd party within the same power system in which case purchase contracts will be integrated to this optimization process, and/or
- from a 3rd party outside the same power system in which case interconnection exchanges will be integrated to this optimization process.

Accordingly purchase and interchange schedules will then be integrated to these timetables.

Power generation control and frequency regulation
The advantage that electric power has of being universally usable is offset by the disadvantage that it is difficult to store. For this reason, the generation of electrical power must take place simultaneously with consumption. The frequency is used as the means of measuring whether generation and consump-

tion are balanced. As long as generation and consumption are in equilibrium, the network frequency corresponds to the rated frequency. If consumption exceeds the power generation, the difference is covered from the kinetic energy of the rotating generator or turbine masses. This drawing of energy, however, causes a reduction in the rotational speed and hence a drop in the frequency. In the reverse situation, in other words, in over-generation, the difference is converted into kinetic energy, and the speed of rotation increases and so too does the frequency.

Because the system frequency is equal at all points in the system, it can be easily used as the input quantity for controlling the frequency of power systems. New setpoint values for the individual generators are determined there from the measured frequency deviation on the basis of technical and economic factors, and transmitted to the decentralized generator control systems by means of telecontrol. If a power supply system is linked to adjacent power systems, the frequency as well as the power exchange with the adjoining systems must be monitored and controlled. This power exchange is taking place over a number of interconnections for which the flow is telemetered.

A PI-type controller, based on a so-called Area Control Error (ACE) updated, typically, every 2-10 seconds, is used to identify the net generation adjustment required to maintain the frequency at or very near its nominal value. Contractual power exchanges can also be accounted for by the same controller such that deviations from the interchange schedules are minimized. Accordingly, individual generation unit adjustments will be calculated and sent as correction signals to the generating units participating to this regulation. This assignment process will also account for the committed (economic or market) schedules of the generating units and the reserve requirements. The set of applications supporting this process is referred to as Automatic Generation Control (AGC).

Transmission network management applications

A transmission network is characterized by a meshed structure, being mesh-operated and having a number of interconnections with one or more external networks. Most, if not all, of its substations are automated. Typically most, if not all, of its switchgear statuses, busbar voltages and line flows are telemetered. The transmission network includes typically an extra high voltage (EHV) part and a high voltage (HV) part. The latter is sometimes referred to as the sub-transmission network. Typically, these measurements are in such a number that they provide more information than it is necessary to solve a power flow. However these measurements include errors due to the accuracy of their measurement equipment and are even sometimes outright wrong due to faulty measurement equipment and/or telecommunication. A least square approach for optimal estimation combined with a statistical analysis for bad measurement is applied to this problem to determine most accurately the state of the network. This function is commonly referred to as State Estimation. The estimation of the network state supplies the operator with a complete load flow solution for supervising the network, including those sections of the network for which no measurement values are available.

The network state estimation is generally followed by a limit value monitoring process that compares the result of the estimation with the operating limits of the individual operational equipment in order to inform the operator about overloads or other limit violations in a timely fashion. The load flow solution of the network state estimation is then used by other network functions such as contingency analysis, short-circuit analysis or optimal power flow.

The contingency analysis carries out a, typically very large, number of "What if?" studies in which the failure of one or more items of operational equipment is simulated. The results of these load flow calculations are then compared against the operational equipment limits in order to assess the network security resulting from an operational equipment failure. Typically a transmission network must remain secure against any single equipment failure (n-1 criterion) and against selected double and other multiple equipment failures which will be all simulated by this contingency analysis application. In the case of security violations other application tools can then be used to identify preventive or corrective solutions for such cases with violations.

The short-circuit analysis simulates different types, e.g. phase-to-ground, of short-circuits at selected node points, typically busbars, of the network to calculate the resulting fault current and fault current contributions from neighboring branches and generating units. The results are then compared to the short-circuit ratings of these near-the-fault equipments, i.e. breaker, branch and/or generating unit, for possible violations. The operator is informed about any limit violations so that suitable remedial action can be taken in a timely fashion.

The optimal power flow attempts to determine the settings of control equipments, e.g. the tap of a transformer, to operate optimally the power system according to some selected criterion and subject to operating constraints such as equipment limits:

- Network loss minimization – network losses are directly related to the amount of reactive power flow and, therefore, to the voltage profile throughout the network. The optimal power flow will minimize the transmission losses by determining the optimal settings of all voltage controls available, i.e. generators, transformers, capacitors, etc.
- Generation cost minimization – The optimal power flow will minimize the total cost of generation by determining the optimal dispatch of each generating units. Today this criterion is applied mostly in pre-deregulation or centralized markets. Variations of this criterion, e.g. involving deviations from market set points, are also solved by optimal power flow in fully deregulated energy markets.
- Network security – In the presence of equipment limit violations the optimal power flow will determine corrective actions in terms of voltage control settings and/or real power control settings to minimize equipment limit violations, i.e. the settings to restore the network to a secure state. Similarly, the optimal power flow can also be used in normal operating conditions to increase the security of the network by increasing operational margins to limits, i.e. by enforcing tighter equipment limits. As increased security margin can be

operationally very expensive it is typically applied only to a few selected critical equipments.

The network calculation functions just described can also be used to study network conditions different from actual conditions. This study mode is used, for example, for checking a planned switching operation.

Distribution network management applications

A distribution network is characterized by a mostly radial and lightly meshed structure that is operated mostly radial. The distribution network typically includes a medium voltage (MV) part and a low voltage (LV) part and is interconnected to the transmission network at HV/MV substations. Depending upon countries few to all of the HV/MV substations are today automated. Under the Smart Grid pressure automation of the MV/LV substations is now accelerating in Europe whilst automation of the MV feeders is now accelerating as well in the US. For these reasons telemetry, e.g. that of power flows, is relatively limited but rapidly increasing (fig. 7.1-7).

Perhaps the most important application in distribution network is the outage management that is responsible for the management of all planned and unplanned outages, the latter part being also referred to as Fault Management. Outage Management integrates information from SCADA (events), metering (events), and customers (trouble calls) to infer one or more concurrent network outages. With the additional help of crews and support from analysis tools, operators are then able to promptly locate faults, isolate faults and restore service. Outage Management will also provide calculation of performance indices that are typically required by the regulator to assess the performance of the utility towards its customers. Outage Management with the support from analysis tools provides also for the coordination of planned outages with the normal operation of the network to ensure safety of the crews and continuity of service to the customers.

Other applications in distribution network belong to one of 2 domains: outage analysis or network analysis. Outage analysis includes typically a fault location application destined at providing the operator with the (visual and descriptive) location of the fault from real-time events using, for example, fault indicators and distance relays, and a fault isolation/service restoration application destined at providing the operator with a switching sequence for isolating the fault and restoring service to customers. As the latter may encounter problems meeting all network security constraints and/or restoring service to all customers one or more switching sequences may be provided to the operator.

Distribution network analysis applications are in many ways similar to those for transmission network but with a different emphasis due to the specific size, structure and mode of operation of the distribution network. One resulting requirement is the need to support balanced, unbalanced and/or unsymmetrical operation of the network. Due to the limited amount of available measurements and their quality a distribution load flow with load scaling has been typically used to determine the state of the network. However, as measurement availability increases, this approach is being progressively replaced by a state-estimation-like approach, e.g. load flow in combination with a least square approach to optimally scale loads to the measurements, to determine the state of the network. This latter function is

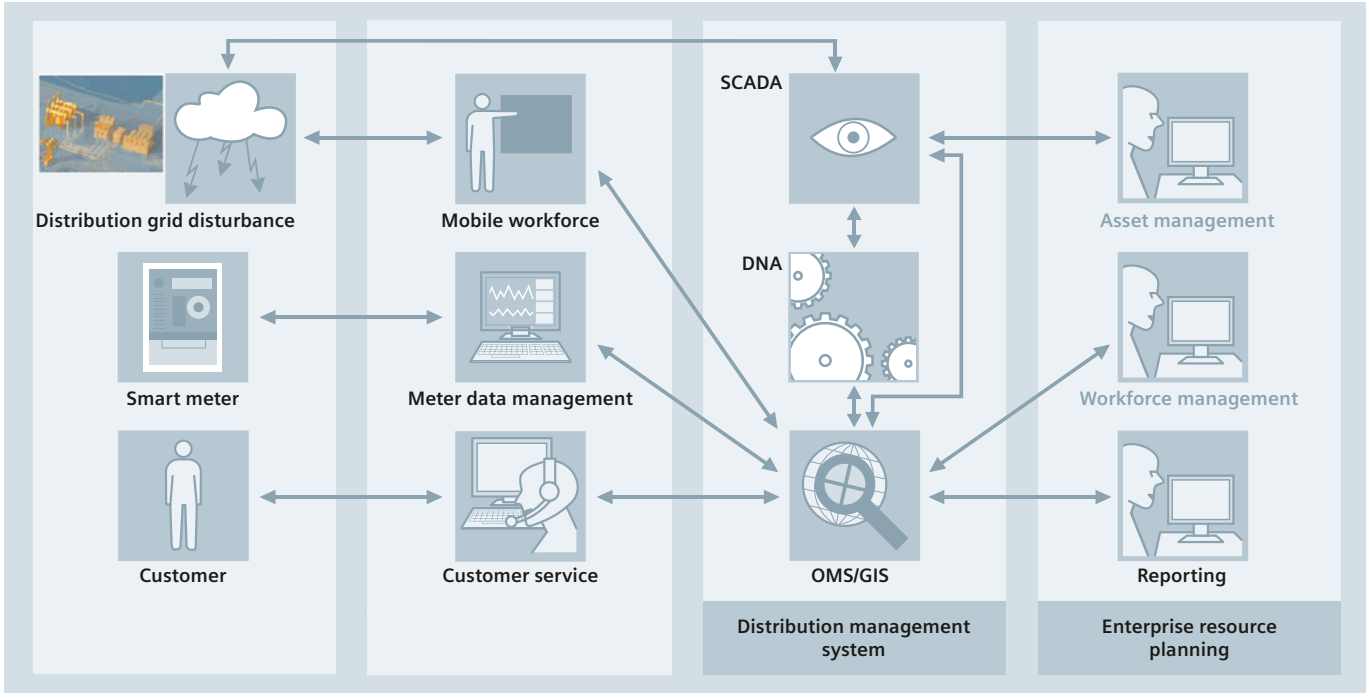


Fig. 7.1-7: **Schematic workflow in a distribution management system**

referred to as Distribution State Estimation. The solution will then be checked against equipment limits for any violations. This application provides the operator with a complete state of the network including security risks beyond that available from SCADA. This application's solution is also used by the other network applications to perform further analysis.

For example, optimal power flow will be used to optimize the operation of the network, either towards minimizing network losses by adjusting voltage controls such as capacitors and transformer taps or towards minimizing network overloads by reconfiguring the network. A short circuit application, similar to that used in transmission, is also used in distribution to identify security risks against short circuits in different parts of the network. A security analysis application is also appearing in distribution to validate restoration procedures in parts of the network that are under abnormal conditions, the applicability of pre- and post-planned-outage procedures ahead of schedule, etc. As the distribution network is often in constant state of change, a relay coordination application is becoming more and more common to validate or suggest adjustments to relay settings under abnormal network configurations.

Load shedding
To insure system stability and maximum service availability during periods of very high demand concurrent to generation shortage and/or large disturbances utilities have, sometimes, no other alternative but to disconnect some loads. This process is typically referred to as load shedding. It is normally used as a last resort solution after all other alternatives (generation reserve, etc.) have been exhausted. This process is supported by an application called Load Shedding (LS).

Typically load shedding will be implemented via direct SCADA commands, Load Shedding Controllers (LSC) and/or under-frequency/voltage relays. In the last two implementations configurations/settings may be downloaded from the control center. Note that these two implementations are the fastest (< 100 ms) but required careful coordination (e.g. 2003 US blackout). The following typical load shedding activations are possible:
- Manual load shedding
- Rotating load shedding (generation shortage for extended time)
- Equipment overload load shedding (delay/avoid tripping of equipment)
- Balancing load shedding (import target deviation, islanding)
- Under-frequency/voltage load shedding (system stability/ voltage collapse).

As conditions return to normal, the load shedding application will also provide support for load restoration, i.e. the manual or automatic re-connection of shed loads.

Load management
As demand has increased much faster than production and network capacity peak demand has become more and more difficult and costly to meet. Considering also that the network is under-used in other periods (e.g. at night) various incentive programs reducing or shifting consumption have been created that would allow the utility to manage some of that peak load should the need arise.

Fig. 7.1-8: **Training on-the-job**

In this context of balancing demand with production, load serving entities, including distribution utilities, must ensure that energy balancing is met whilst still respecting their energy purchase contracts. This process includes the forecasting of the customer loads, the optimal scheduling (typical cycles of 15, 30 or 60 minutes) of their dispatchable means to meet the forecasted demand and the energy purchase constraints, the monitoring of this plan's execution in real-time (typical cycles are 30, 60 or 120 seconds), and, when necessary, the implementation of corrective actions including load control. The first two steps are implemented using similar tools to those already described earlier albeit with adaptations, that is load forecasting and energy resource optimization. The last two steps will monitor all resources and control those resources available to control towards meeting energy purchase schedules over contractual (tariff) time periods and towards balancing energy as demand fluctuates outside the forecast. The load control that may be required must, of course, account for slow, fast and time-constrained load response.

In the near future, this process will integrate Demand Response, a concept identifying dynamically the loads to be available for such control.

Training simulator
The growing complexity of existing power systems places increasing demands on operation personnel (fig. 7.1-8). Efficient training simulators are therefore required for carrying out the necessary comprehensive hands-on training. The following areas can be covered with training simulators:
- Familiarization of operation personnel with the control system and the existing network
- Training of experienced personnel to changes in network, operating procedures, tools, etc.
- Training of personnel to daily work as well as to emergency conditions (e.g. blackouts)
- Simulation and analysis of operational incidents (post-mortem or anticipated) towards improving on existing operating procedures
- Testing of possible network expansions and analysis of alternatives, testing of new tools and analysis of results, etc.

For the training of personnel, training simulators must reflect accurately the power system behavior and provide to the operator the very same tools, including visualization, as those used in the control center for an effective training. The training simulator includes 4 essential components (fig. 7.1-9):
- A training management component
- A power system simulation component
- A telemetry simulation component
- A copy of the management system (EMS, TMS, DMS or GMS).

The power system simulation component is responsible for the accurate simulation of the dynamic behavior of the managed system, i.e. that of all its field equipments (generating units, network and loads). The telemetry simulation component feeds into the management system copy the simulated field data as they would normally come from field equipments into the control center.

The training simulator provides to the trainee an environment identical to that used in operation and to the instructor an environment that allows him to create training scenarios, influence (with or without knowledge of trainee) the training session, etc.

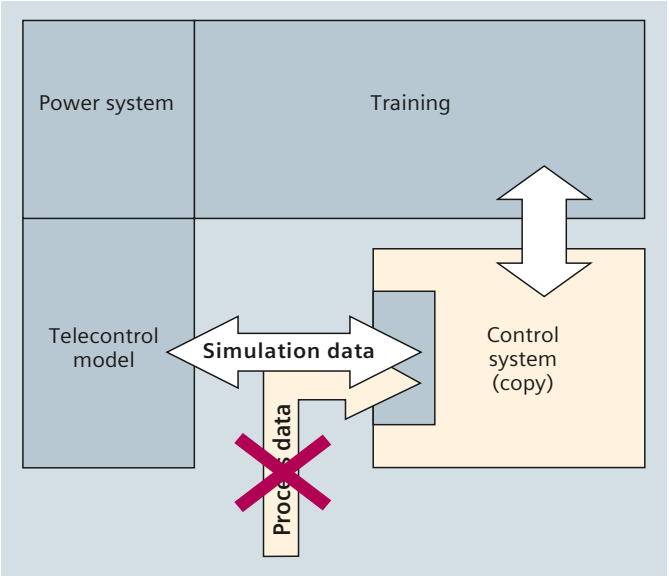


Fig. 7.1-9: **Block diagram of a training simulator**

Operator Training Simulator (OTS)
OTS is based on 4 key components (fig. 7.1-9):
- A training management component
- A power system simulation component
- A telemetry simulation component
- A copy of the control system (e.g. EMS).

The training management component provides tools for creating training sessions, executing training sessions and reviewing trainee performance. It provides tools to
- initialize the training session, e.g. from real-time or a saved case
- define the system load profile
- create event sequences, e.g. a breaker opening, a telemetry failure, etc., that can be either time triggered, event triggered or command triggered
- create training scenarios, i.e. a number of event sequences, to be activated during the training.

It also provides start/stop and pause/resume functions for the execution of the training session. During the training session it is possible for the trainer to create new events and/or modify the running scenario.

The power system simulation component provides a realistic simulation of the power system behavior to support training from normal operation to emergency operation including islanding conditions and blackout restoration. The simulation is based on a long-term dynamic modeling of the power system including:
- Load modeling with voltage & frequency dependency
- Generation modeling with governor, turbine/boiler and generator models
- Frequency modeling
- Voltage regulator modeling
- Protection relay modeling
- External company LFC modeling.

The telemetry simulation component provides the simulation of the data communication between the power system and the control system. It transfers as simulated field telemetry the results of the power system simulation to the control system copy. And it processes all commands issued by SCADA (operator), LFC, etc. and transfers them to the power system simulation. This simulated telemetry can be modified via the scenario builder by the trainer to reflect measurement errors, telemetry or RTU failures, etc.

This operator training simulator provides a dedicated environment for the trainee (operator) and one for the instructor that allows the instructor to influence the process in order to force responses from the trainees. The trainee interface is identical with that of the control system so that, for the trainee, there is no difference in functionality and usability between training and real operation.

Multi-Utility
Some distribution utilities will manage the distribution of multiple commodities, e.g. electricity, district heating, gas and/or water. Whilst the distribution process, for example with load management, is commodity specific, inter-dependencies will be created either by the procurement process or the production model.

It is not unusual to find in distribution cogeneration power plants, also referred to as combined heat and power (CHP) power plants, providing electrical power and district heating. Management of these 2 highly integrated commodities will require adapted tools accounting for the high inter-dependencies existing between the production and the demand of these 2 commodities.

7.1.2 Network Control Centers in a Deregulated Energy Market

As a result of the movement towards deregulation and liberalization of the energy business, the electricity industry has undergone dramatic changes since the beginning of the 1990s. This process has been marked by the following characteristics:

- Competition wherever possible – electrical energy is traded as a commodity. This initially affects power generation, but other services can also be offered on a competitive basis.
- Commercial Separation of the natural network monopolies from the competitive elements. This impacts numerous areas, such as planning, operation and maintenance of formerly integrated systems.
- Access to the networks by third parties. This is an essential precondition for open trading in electrical energy via the natural network monopoly.
- Regulation of the network monopolies by a public agency. Because the network is the basis for competition in the electrical energy market, considerable importance is attched to reliable, economical and neutral network operation. In order to ensure such operation, a new regulatory element must be introduced at the same time that other sections of the electricity business are deregulated.

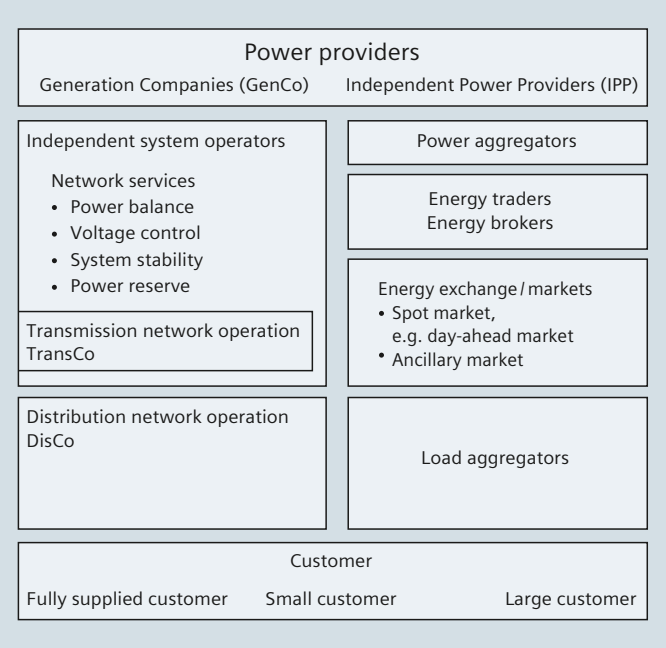


Fig. 7.1-10: **Players in the deregulated energy market**

Restructuring models

In a deregulated environment of the type just described, the power companies that traditionally had a vertically integrated structure start to split into companies responsible for power generation (GENeration COmpanies), transmission (TRANSmission COmpanies), distribution (DIStribution COmpanies) and energy service (Load Serving Entities – Service Provider Companies). This restructuring opened the door to many new market players (fig. 7.1-10), such as electricity traders and brokers who purchase energy from GenCos, independent power producers (IPPs) or other sources and resell it.

The technically critical part of deregulation concerns the operation of the overall system. Because there is no longer integrated operation of generation, transmission , distribution and energy service in one business unit, a dedicated organization must take over the responsibility for observing specific electrical energy quality standards such as frequency control, the voltage level and provision of adequate generation and transmission reserves for emergencies. When implemented independently of all other energy business activities this organization is referred to as an Independent System Operator (ISO), e.g. in North America, and when integrated with a TransCo it is referred to as a Transmission System Operator (TSO), e.g. in Western Europe. An ISO is typically managing the energy market over a grid that encompasses multiple TransCos whilst a TSO is typically managing the energy market over the grid under its own TransCo's responsibility. ISOs are also referred to as Regional Transmission Operators (RTOs).

The ISO/TSO does not have its own generation capability. Therefore it must purchase regulating energy (active and reactive power) from the power producers. Whilst many energy contracts are established as bilateral contracts some of the energy can also be bought/sold in an open energy market facilitated by one or more energy exchanges, e.g. the European Energy Exchange (EEX) in Germany. This market model is typically referred to as a spot energy market and is most common in TSO-structured energy markets for better market transparency and liquidity. Energy markets are often structured along time lines such as day-ahead, intra-day, etc. energy markets and types such as balancing, reserve, etc. energy markets. The proportion of energy traded on the spot market compared with what is fixed by bilateral agreements can vary from one country to another.

New requirements for network control centers

Energy markets models vary significantly from region to region and typically take many years to reach relative maturity, i.e. stable market rules. There is, therefore, a strong requirement for high flexibility/customization in the proposed market solutions (fig. 7.1-11).

The ISO/TSO whilst responsible for rules that have been enforced for decades are now facing a much more complex process using market mechanisms to acquire the information and means enabling them to enforce these rules; information and means that are now own and controlled by the many competing market participants. And the ISO/TSO, as it gets access to the data necessary to fulfill his role and responsibilities from the market participants, will need to enforce absolute confidentiality since these data reflects often market participants positioning, i.e. market competitive data.

Similarly, network planning necessary to support a properly functioning energy market, i.e. one operating without congestion, has become a real challenge between the ISO/TSO, TransCos and these same market participants.

Last but not least, energy markets require transparency and auditing. Many services that used to be bundled must now be all separately identified and accounted for, detailed market compliance monitoring must be performed, and extensive archiving of it all must be possible.

Communication
As extensive communication between the control center and the various market participants such as power producers, distribution companies, energy exchanges and traders will increase greatly. Whilst some communication media have been already in use in the control center, the use of open media such as internet will expand significantly. And the many new market interactions such as network access/capacity requests, ancillary market requests, etc. will require new solutions using this new communication infrastructure. The OASIS system (Open Access Same-Time Information system) for reserving transmission capacity in the United States is an example of an existing system of this kind.

Fundamental changes to the properties of network control systems
Many of the ISO/TSO functions will no longer be self-serving but instead will be to serve the market participants towards open and fair access to the network. Whilst many functions will remain the same as those prior to unbundling, many of the tools needed by the ISO/TSO for executing them will rest with the market participants. The ISO/TSO will therefore need to buy the use of these tools from the market participants whilst building its own revenue through network access fees. Many new functions will also be required to support an open and fair access to the network to all market participants particularly when to manage network congestion (e.g. locational marginal pricing), transfer capacity limitation (e.g. cross-border capacity auctioning), etc.

To guarantee open and fair access to the network and equal treatment between all market participants, many of these functions will be using market mechanisms. This implies that many of the solutions developed for these functions will be financially-driven whilst still addressing the same physical problems and therefore will require a lot more integration with back office functions such as, for example, settlement.

Network calculations
The basic functions, such as state estimator, load flow calculation, short-circuit calculation and contingency analysis, will not normally be influenced by the restructuring. However an application such as optimal power flow considering availability/controllability of generation resources will be affected by the restructuring of the energy business. The total cost optimization of generation is no longer the responsibility of the ISO/TSO but that of each market participants. But the use of generation (MW and Volt/VAr) whether for security violation relief or network loss reduction, still responsibilities of the ISO/TSO, will require the application to account for the cost of using (variable cost) that

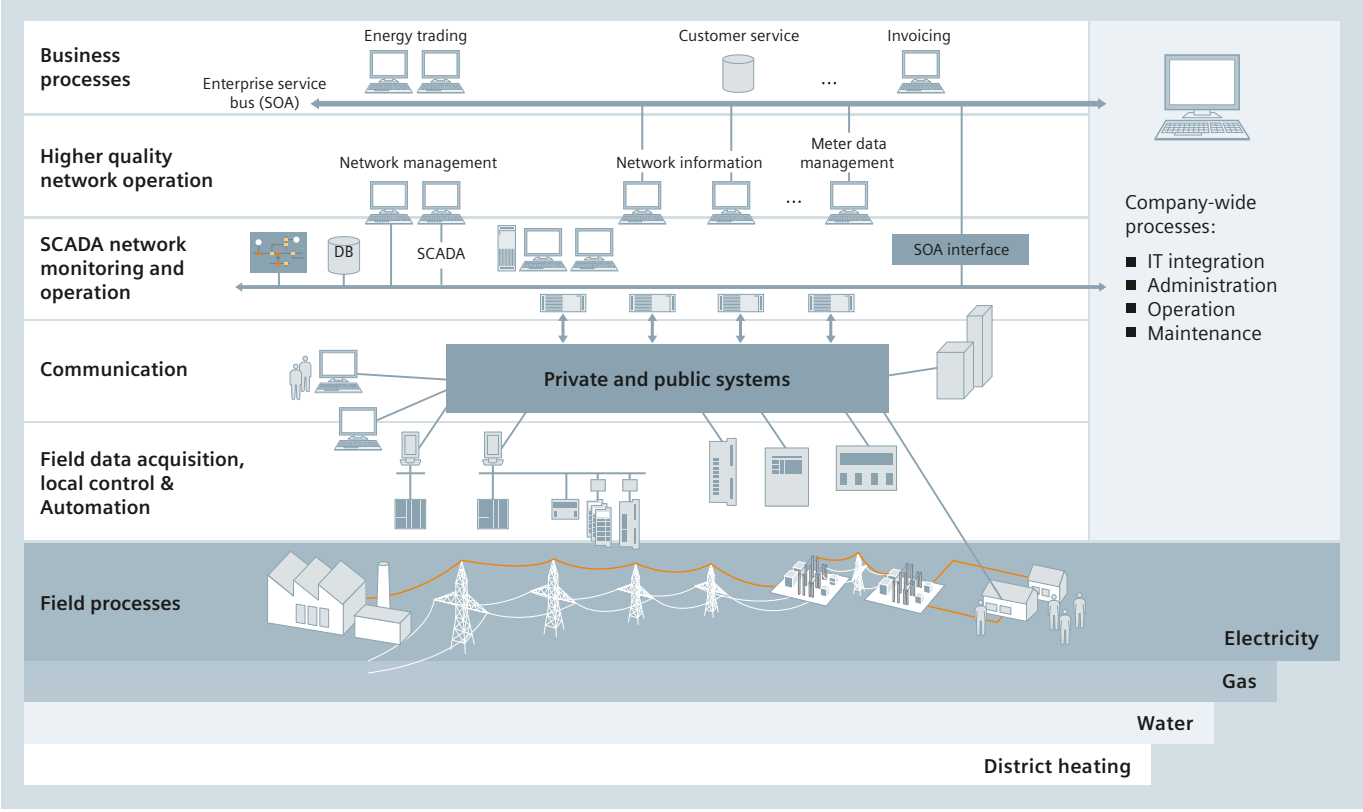


Fig. 7.1-11: **: Integration on the various process layers**

resource within the terms agreed in a separate market based process. The cost of availability (fixed costs) is already included in this market based process.

Power generation planning
Power generation planning is no longer the responsibility of the ISO/TSO and therefore no longer considered within the control center. However its results must be communicated by the market participants to the ISO/TSO for it to assume its network operation and security responsibilities.

This process (fig. 7.1-12 and fig. 7.1-13) is quite elaborate and varies from market to market (e.g. with/without exchange, single/multiple buyer, etc.) but with some constants with respect to the part under the ISO/RTO responsibility. The ISO/TSO basic process consists in collecting all market participants' positions, i.e. their production plans, and validating it against network security whilst satisfying load forecasts and planned outage schedules. In the case network security is not satisfied market signals are returned to the market participants for a new production plan and this until network security is satisfied. In parallel or concurrently the ISO/TSO will also request from the market participants bids to provide power for ancillary services, e.g. regulating power. These bids will be finalized upon a market clearing at the market clearing price. Of course, these bids will be integrated to the load serving energy schedules in the above mentioned network security validation process. These market mechanisms will be, typically, performed at least one day ahead (day-ahead market), and one hour ahead (real-time market) of real-time operation. This process will then be completed on the next day by market settlement to address the actual energy served.

Power generation control
The full set of generation control applications still apply with, however, some adjustments. Indeed target generation timetable is now defined by the market participants (see process description above). And the availability and limits of regulating power and reserve power are now defined by the process where the ISO/TSO acquires access to and use of these resources from the market participants (see process description above). The production cost monitoring application is still sometimes used with adjustment to account only for the regulating costs.

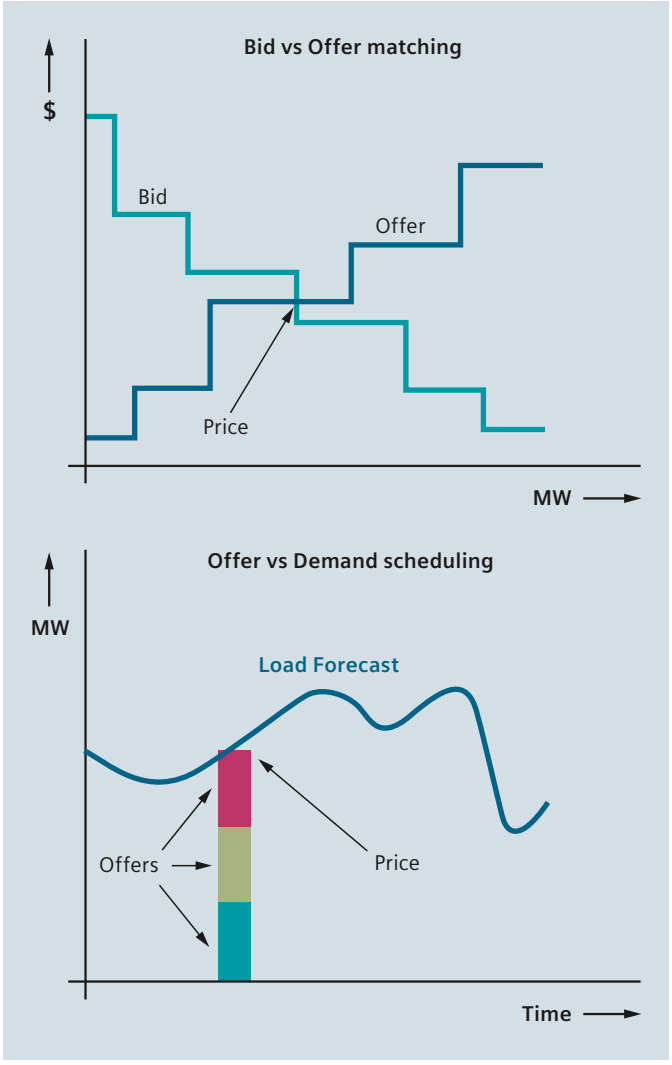


Fig. 7.1-12: **Fundamentals**

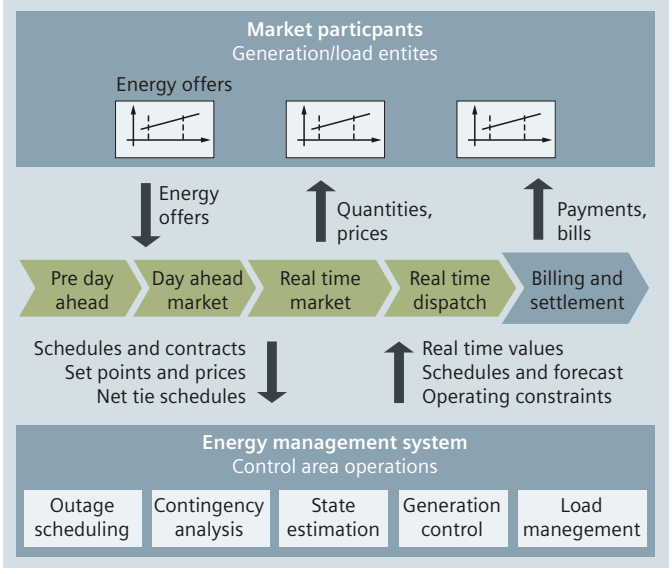


Fig. 7.1-13: **ISO/TSO Overview**

7.1.3 Common Information Model

In order to survive in the deregulated energy market, power companies today face the urgent task of optimizing their core processes (fig. 7.1-14). This is the only way that they can survive in this competitive environment. One vital step here is to combine the large number of autonomous IT systems into a homogeneous IT landscape. However, conventional network control systems could only be integrated with considerable effort because they did not use a uniform data model standard. Network control systems with a standardized source data based on the Common Information Model (CIM), in accordance with IEC 61970, and its extensions IEC 61968 (DMS) and IEC 62325 (energy market), offer the best basis for IT integration.

CIM – key to interoperability and openness
The Common Information Model (CIM) defines a common language and data modeling with the object of simplifying the exchange of information between the participating systems and applications via direct interfaces (fig. 7.1-15). The CIM was adopted by IEC TC 57 and fast-tracked for international standardization. In the United States, CIM is already stipulated by the North American Reliability Council (NERC) for the exchange of data between electricity supply companies. The standardized CIM data model offers a very large number of advantages for power suppliers and manufacturers:

- Simple data exchange
- Standardized CIM data remains stable, and data model expansions are simple to implement
- As a result, simpler, faster and less risky upgrading of energy management systems, and if necessary, also migration to systems of other manufacturers
- The CIM application program interface creates an open application interface. The aim is to use this to interconnect the application packages of all kinds of different suppliers per "Plug and Play" to create an EMS.

CIM forms the basis for the definition of important standard interfaces to other IT systems. Siemens is an active member of the standardization bodies and the working group in IEC TC 57, playing a leading role in the further development and international standardization of IEC 61970 and the Common Information Model. Working group WG14 (IEC 61968 Standards) in the TC57 is responsible for standardization of interfaces between systems, especially for the power distribution area.

Standardization in the outstation area is defined in IEC 61850. With the extension of document 61850 for communication to the control center, there are overlaps in the object model between 61970 and 61850. In order to accelerate harmonization between documents 61970 and 61850, TC57 has set up a working group (ad hoc WG07).

The primary future challenge is to extend the standard beyond the control center. Once the standard is extended, it will allow full data management and data exchange between the transmission, distribution, planning, and generation areas of the enterprise. Especially urgent at the present time is to move the standard into the newest areas of smart grid, Advanced Metering Infrastructure (AMI), and Home Area Network (HAN).

CIM data model and packages
The CIM data model describes the electrical network, the connected electrical components, the additional elements and the data needed for network operation as well as the relations between these elements. The Unified Modeling Language (UML), a standardized, object-oriented method that is supported by various software tools, is used as the descriptive language. CIM is used primarily to define a common language for exchanging information via direct interfaces or an integration bus and for accessing data from various sources.

The CIM model is subdivided into packages such as basic elements, topology, generation, load model, measurement values and protection. The sole purpose of these packages is to make the model more transparent. Relations between specific types of

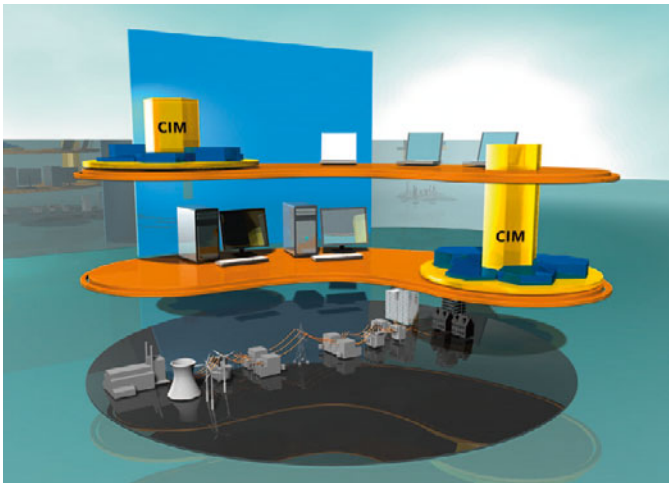


Fig. 7.1-14: **The Common Information Model as key-enabler for interoperability**

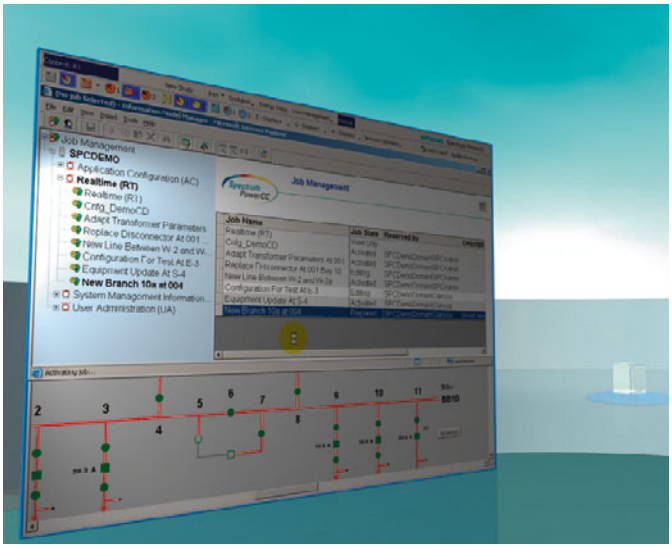


Fig. 7.1-15: **Data engineering with Information Model Manager**

objects being modeled may extend beyond the boundaries of packages.

Topology model
The electrically conductive connections between the elements are defined via terminals and nodes (connectivity nodes). Every conductive element has one or more terminals. A terminal connects the element, such as a generator, or one side of, for example, a circuit-breaker, to a node. A node can hold any number of terminals and provides an impedance-free connection linking all elements connected to it. A topology processor can determine the current network topology via these relations and with the current states of the circuit-breakers. This topology model can also be used to describe gas, water, district heating and other networks for tasks such as modeling interconnected control centers.

Measurement value model
The dynamic states of an electric network are displayed in the form of measurement values. Measurement values can contain numerical values, such as active/reactive power, current and voltage, or discrete states such as a 1-switch position. Measurement values always belong to a measurement. A measurement always measures a single physical quantity or a state of the relevant object. It is either allocated directly to the object or to a terminal of the object if it is significant at which end of the object the measurement is made, such as a measurement at the beginning of a high-voltage line. A measurement contains one or more measurement values, e.g., the value transmitted by SCADA, or the value determined by the state estimator or by the voltage/reactive power optimizer. Whether the current value comes from the expected source or is a substitute value can also be indicated if, for example, the connection to the process is interrupted (fig. 7.1-16).

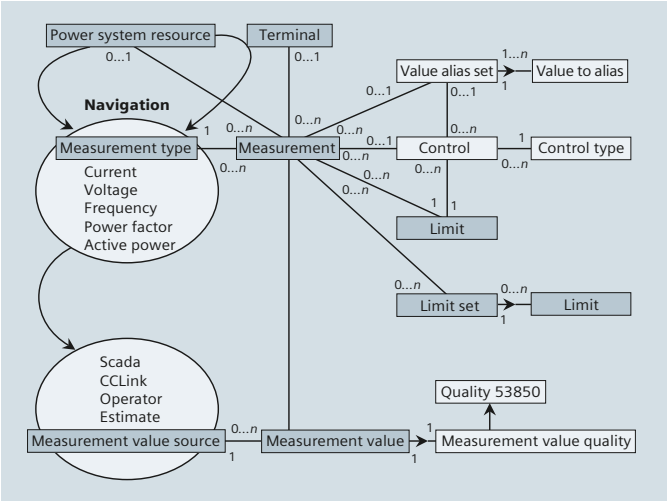


Fig. 7.1-16: **Measurement value model**

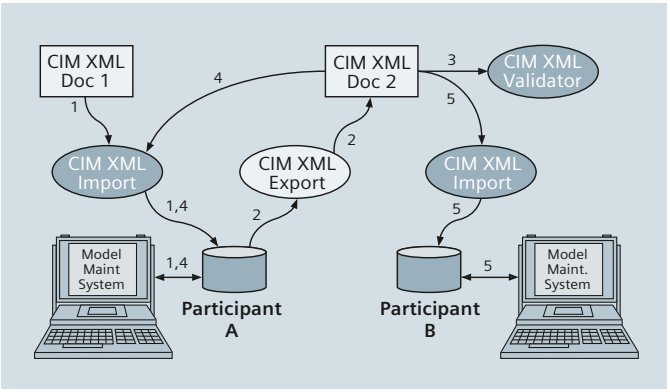


Fig. 7.1-17: **Principle of the interoperability test**

Interoperability tests and model data exchange
Since September 2001, North American Electric Reliability Corporation (NERC) has prescribed the CIM/RDF/XML formal for the exchange of electrical network data between network security coordinators. With funding from the Electric Power Research Institute (EPRI), leading manufacturers of complete EMSs or partial components (ABB, Alstom, CIM-Logic, Langdale, PsyCor, Siemens and Cisco) have started planning interoperability tests and developing the tools necessary for this. CIM XML interoperability tests began in December 2000 and take place annually today. Interoperability (IOP) testing proves that products from different participants can exchange information and provide the interfacing requirements based on the use of the IEC standards that have been developed to date. An additional feature and objective of this and future IOP tests is to verify and validate that changes made to the IEC standards have been implemented and do not prevent or impede data exchange or interaction between the participants. The verification of annual IEC specification updates is an integral part of the IOP testing process. The IOP test report gets published afterwards and fully documents all the results as well as the issues discovered during testing.

The principle of the test can be seen in fig. 7.1-17. Participant A imports the test data using the tool, modifies the data and exports it for further use by participant B. Participant B imports the data, processes it and amends it and exports it for participant C, and so on. Some participants provide a model that is used during the IOP testing (for example: Areva 60 Bus Model, GE WAPA 262 Bus Model, SNC-Lavalin 60 Bus Model, and Siemens 100 Bus Model). Typically full and incremental model are exchanged and validated between the participants. Power flow solution tests are intended to verify the correct exchange of power system model files including generation and load through the execution of power flow applications. In addition specific tests focused on implementing the latest annual IEC standard contents are performed specifically.

7.1.4 IT Integration and Service-Oriented Architecture

In order to survive in the deregulated energy market, power companies today face the urgent task of optimizing their core processes. This is the only way that they can survive in this competitive environment. The aim is to make the system architecture modular and component-based so that a flexible configuration and IT integration can be implemented in a cost-efficient manner. The crucial step here is to combine the large number of autonomous IT systems into one homogeneous IT landscape. However, conventional network control systems could only be integrated with considerable effort because they did not use any integration standard as none did exist. Network control systems designed with a Service Oriented Architecture (SOA) offer the best basis for IT integration.

Open systems through the use of standards and de facto standards

A modern network control system provides the basis for integration of an energy management system in the existing system landscape of the utility through the use of standards and de facto standards.

- IEC 61970 Common Information Model (CIM) defines the standard for data models in electrical networks. It supports the import and export of formats such as XDF and RDF, which are based on the XML standard
- Web-based user interface, webtechnology
- Standardized PC hardware instead of proprietary hardware Client/server configuration based on Standard LANs and protocols (TCP/IP)
- Open interfaces (OBCD, OLE, OPC, etc.)
- RDBMS basis with open interfaces
- Nationally and internationally standardized transmission protocols (IEC 60870-5, IEC 60870-6)

Service-oriented architecture

A modern network control system provides a service-oriented architecture with standardized process, interface and communication specifications based on standards IEC 61968 and IEC 61970. They form the basis for integrating the network control system in the enterprise service environment of the utility.

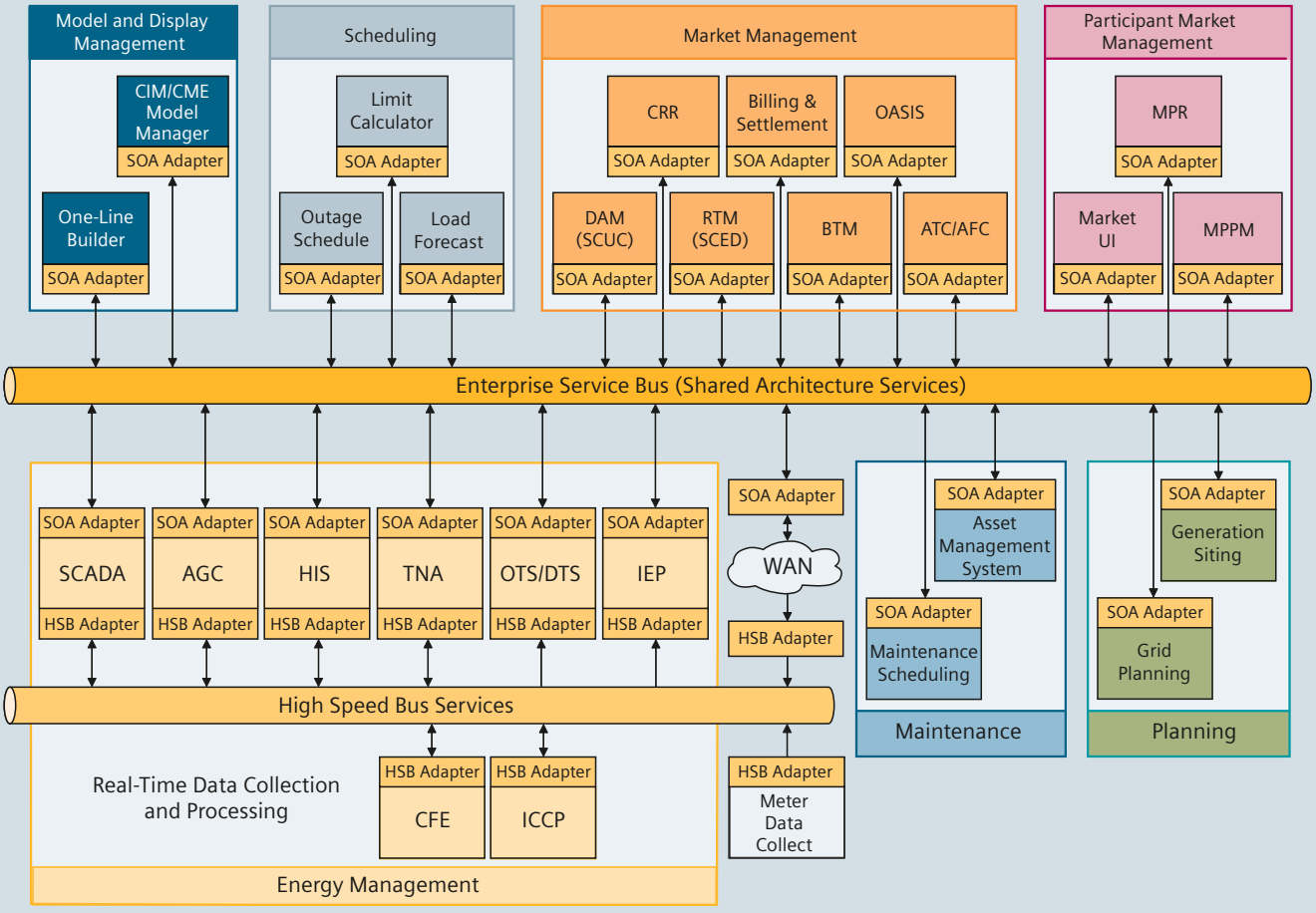
The services of a control system comprise:

- Data services with which, for example, the databases of the core applications can be accessed, e.g., readout of the operational equipment affected by a fault incident in the power supply system
- Functional logic services, e.g., for starting a computing program for calculating the load flow in the power supply system
- Business logic services that coordinate the business logic for specific energy management work processes of the participating systems, e.g., fault management in the network control system within the customer information system at the utility.

The network control system is one of many systems in the IT network of the utility that interacts with other systems and that offers and uses services such as:

- Services forming part of the offered scope of functions of the network control system
- Services that are used by the network control system and are provided by other systems and applications

Fig. 7.1-18 shows a typical example of the incorporation of the network control system in the enterprise service environment of the utility. Further planning with respect to the required work processes and integration in the heterogeneous system landscape of the utility are based on this incorporation.



AFC	Available Flow Gate Calculation
AGC	Automatic Generation Control
ATC	Available Transmission Capacity Calculation
BTM	Bilateral Transmission Capacity
CFE	Communications Front End (RTUCS)
CIM	Common Information Model
CME	CIM Market Extension
CRR	Congestion Revenue Right
DAM	Day-Ahead Market
FEP	Front End Processor
HIS	Historical Information System
IEP	Intelligent Event Processor
ICCP	Inter Control-Center Communication Protocol
MPR	Market Participant Registration
MPPM	Market Participant Prudential Management
OASIS	Transmission Reservation
OTS	Operator Training Simulator (DTS)
RTM	Real-Time Market
SCUC	Security-Constrained Unit-Commitment
TNA	Transmission Network Applications

Fig. 7.1-18: **Spectrum Power SOA (Service-Oriented Architecture): Integration of the network control system in the enterprise Service environment of the utility**

Integration into IT networks

A modern network control system acting as an energy management system fits harmoniously into the IT networks and the existing IT landscape of the utility (fig. 7.1-19). The network control system is one of many systems in the IT network of the utility that interacts with other systems. The following are some of the points defined for the IT integration process: Access to the system by intranet users, e.g., from the back office:

- Configuration for the DMZ (Demilitarized Zone) Integration of the corporate network, such as for e-mail notification
- Protected area for the application and SCADA Servers
- TCP/IP-based communication to substations or to adjoining control centers
- Configuration of switches/routers
- Password protection and requirements.

Fig. 7.1-20 shows an example of the integration of the network control system in the IT network of the utility. It forms the basis for further planning with respect to the tasks required during IT integration in the heterogeneous system landscapes of the utility.

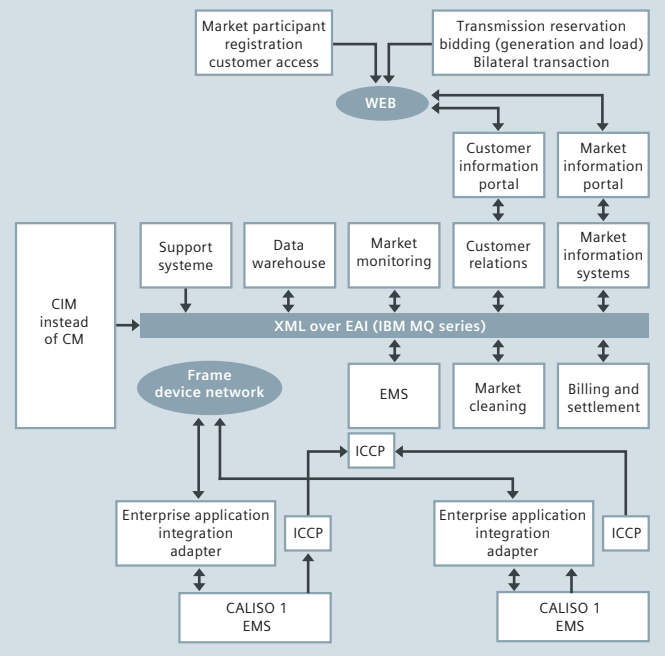


Fig. 7.1-19: **Service-Oriented Architecture of applications in the IT-landscape of a large utility**

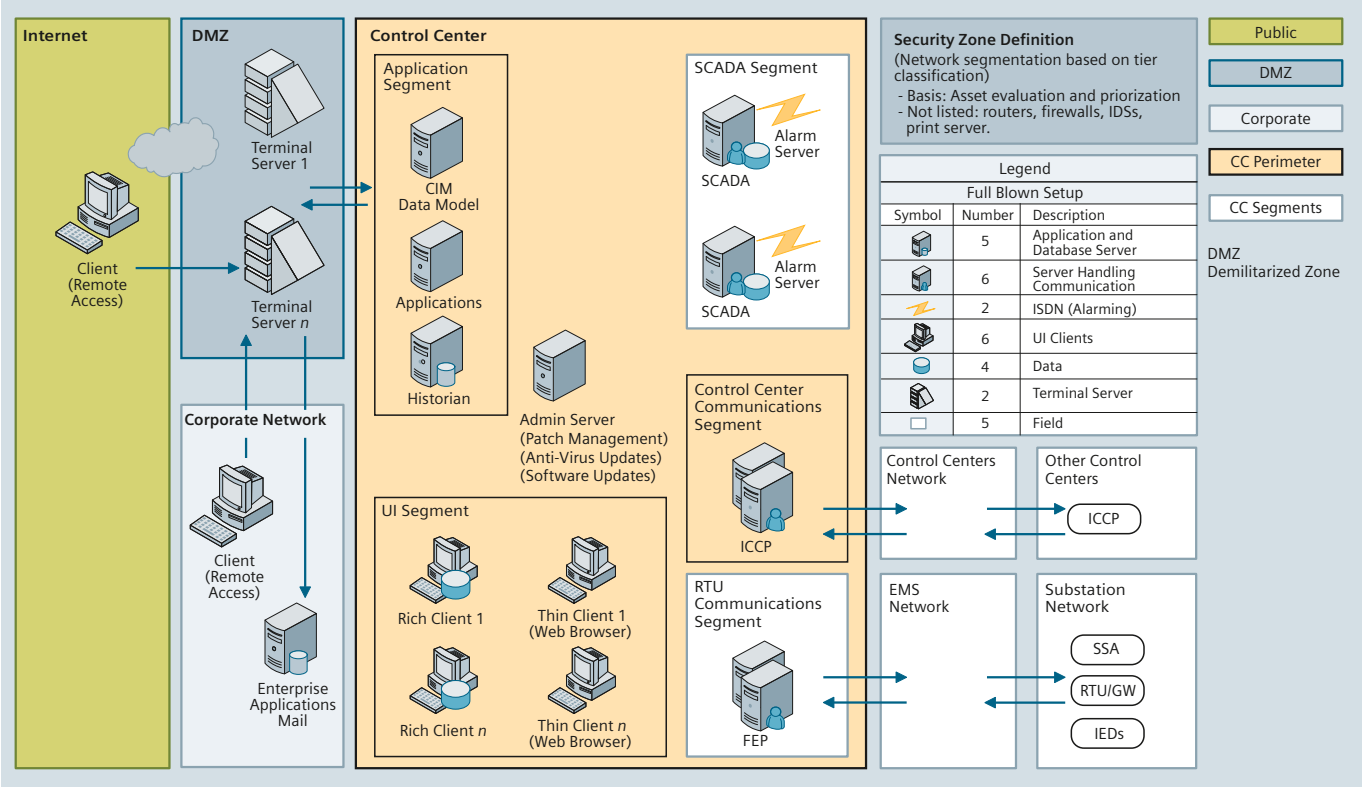


Fig. 7.1-20: **Integration of the network control system in the IT network of the utility**

7.2 Energy Management Products and Solutions

7.2.1 Spectrum Power Control Systems

Siemens has supplied more than 1,600 computer-based control systems for power systems worldwide. The result of these many years of experience is the development of the product family Spectrum Power™ – control systems for electric power systems as well as for gas, water and district heating networks (fig. 7.2-1).

A Spectrum Power control system is divided into various Subsystems. On the basis of a minimum configuration for operation, it is possible to add subsystems to meet the other requirements in terms of additional functions, structure and size of the system. With its modular structure, the system can be expanded with little effort, even subsequently. Modules can be replaced or new modules can be added to implement the required modifications. On the basis of the standard system, open programming interfaces permit individual adaptations and subsequent expansions for new or existing customer-specific components. In a basic configuration, a Spectrum Power control system encompasses the following components, which are described in greater detail in the remainder of this section:

- Basic services
  To ensure that the basic functions are provided, such as real-time database services, data exchange and coordination of computers (e.g. redundancy) involved in the control center
- User interface
  For providing user-friendly, powerful and graphically oriented interfaces to the operator
- Information Model Management
  For data entry and data maintenance of network data, single-line diagrams and data exchange with other IT systems
- Communication front end
  For interfacing the field remote terminal units (RTU) to the process
- ICCP and ELCOM
  For Inter-communication between Control Centers based on Standard-protocols (ICCP) and defacto standard protocols (ELCOM).
- SCADA applications
  For implementing the functions required for system operation, i.e. system monitoring and controlling.

In addition to these components, the following Subsystems, which are described in greater detail in the remainder of this section, are available for expanding the functionality. They are used and configured to match the tasks and size of the control systems:

- Multi-site operation of control centers
  For the flexible and dynamic system management (modeling and operation) in multi-site configuration
- Historical Information System
  For the archiving and subsequent reconstruction of the process data

Fig. 7.2-1: **Spectrum Power control system**

- Forecasting applications
  For the long-, medium- and short-term forecasting of system loads
- Power scheduling applications
  For optimal resource planning, including commitment and planned dispatch, of the power generating units
- Power control applications
  For the monitoring and control, i.e. real-time dispatching, of the power generating units participating to frequency regulation
- Transmission network applications
  For fast and comprehensive analysis and optimization of the transmission network operation
- Outage management applications
  For efficient management of planned and unplanned outages in the distribution networks
- Distribution network applications
  For fast and comprehensive analysis and optimization of the distribution network operation

- Expert system applications
  For supporting the operator in critical and complex tasks in the field of distribution network faults
- Training simulator
  For training the operator to all range of network behaviors with the tools and user interface as used in operation.

SCADA applications
The SCADA applications group together all Spectrum Power functions that are the minimum required to operate a network control center. SCADA contains all functions for signaling, measuring, controlling and monitoring (fig. 7.2-2).

The basic data processing uses preprocessed data of the communication front end for further processing. Value changes are monitored, and data are distributed to other subsystems and written to the operational database. Moreover, calculations, logic operations and special processing functions for special data types (e.g., metered values) are performed.

Spectrum Power control systems use a mature network control concept that reduces the execution time and increases operational reliability. Network control can be performed for any elements of the energy distribution network from any operator station that is set up to perform that task. Individual switching operations and switching sequences can be implemented. Online adaptations of interlock conditions and safety features permit network expansion without interrupting operation (using a preliminary test in study mode). Complex switching operations such as busbar changeover and line switching permit reduced switching times and therefore fast execution of the switching operations. To ensure operational reliability, the network control concept of Spectrum Power contains various additional safety features such as checking the various interlock conditions, network reliability monitoring of planned switching operations, and monitoring of network changes during switching operations.

Spectrum Power control systems allow the user to freely position temporary network modifications such as temporary jumpers, earth connections and isolating points online or to remove them without having to resort to source data management. Temporary network modifications become active in the topology immediately (interlocking, path tracing, etc.). They remain active in topology until they are removed again. The set temporary network modifications can be parameterized.

Switching procedure management provides the control room personnel of a dispatch center with powerful tools for creating, checking and executing switching operations in the network (in the process and study mode). Up to 1,000 switching procedures can be managed; each switching procedure can contain up to 100 actions.

Acoustic alarms and blinking display elements on the screen inform the user about alarms and deviations from the normal state of the power supply system. Logs are used to record alarms and indications. Several logs can be kept. Each log can be assigned to a certain output unit. By using fault data acquisition, the dispatch center personnel and system engineers can analyze the states prevailing in the power supply system before and after a fault. Snapshots, trend data and state changes are stored in this analysis.

Fig. 7.2-2: **Large display wall for network operation in a large control center**

Interactive topological path tracing allows the operator to determine paths between electrically connected equipment in the distribution network. The network coloring function controls the color display of equipment depending on various properties of individual items of equipment. Partial networks, network groups (e.g., voltage levels) and operating states of equipment (e.g., dead, earthed, undefined) can be highlighted in different colors.

The report generator is an easy-to-use tool for simple and fast creation, management and output of reports. An SQL interface permits direct access to the database of the system. The layout can be configured individually by the operator using the graphic editor (in the formal world view). The user can define variables for dynamic values that are updated automatically when a report is created. Moreover, data views (tables and station diagrams) can be linked in, and their dynamic elements are updated automatically.

Basic system services
The Spectrum Power contains various basic functions (services and systems) that govern the fundamental functions required to operate a network management system. Based on the operating systems and relational databases, these functions are used to organize data management, data exchange and communication between the modules installed on distributed computers.

The multi-computer system is a subsystem that manages communication between distributed computers and various services for hardware and software redundancy, multi-computer coordination and system state monitoring. Bidirectional communication between individual programs of the system is possible. The following functions are implemented:

- Management of the operating contexts
- Process Operation (normal state of the system)
- Study context (to perform "What if?" studies)
- Test context (system test after data or program modifications)
- Training (context for training Simulator)
- Management of computer states
- Redundancy
- Monitoring
- Error detection and automatic recovery
- Data consistency
- Start-up coordination and switchover
- Updating and synchronization of date and time

The high-speed data bus is a communication system that organizes the link between the user programs and the basic system via standardized interfaces. This communication is provided between individual program modules within a computer. Communication between several computers is conducted via the local area network (via TCP/IP). The high-speed data bus is also used as the link between the modules and the database. Further features are:

- Integrated time processing
- Support of redundant LANs
- Support of the test and Simulation mode
- Performance of immediate program activation after delay or cyclically

The database system of Spectrum Power consists of an operational database for real-time operation (process and application data) and a relational database that is used by the Information Model Management. Features of the database system are:

- Standard model for all process and application data
- Incremental data changes
- Import and export of data

Information Model Management

The Spectrum Power Information Model Management (IMM) is the data modeling, data maintenance and data exchange tool specifically designed to cost effectively and efficiently manage the power system model data for the EMS/DMS applications, SCADA, communication to RTUs, ICCP and other enterprise information (fig. 7.2-3). It provides a single, central location to

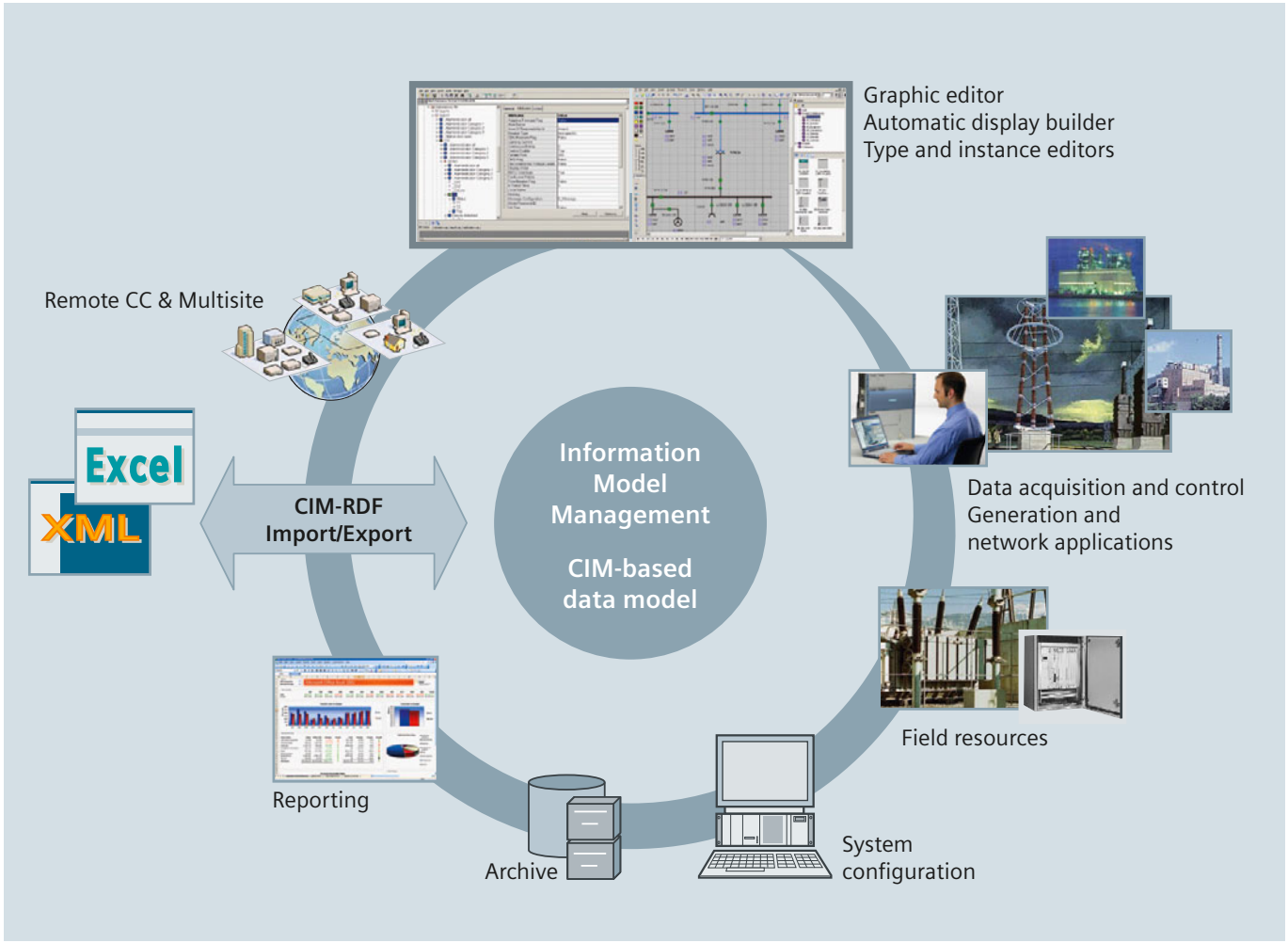


Fig. 7.2-3: **The Spectrum PowerCC Information Model Management provides the functionality to enter and maintain all power-system-related data**

input and maintain all power system-related data and is fully compliant with the international Standard for a Common Information Model (CIM), IEC 61970. The IMM embraces widely accepted industry standard technology such as a commercial Relational Database Management System (RDBMS) and Extensible Markup Language (XML).

The task of IMM within the power control system is to manage the input of the data of the electric power system into the database, both during commissioning of the system and afterwards for subsequent modifications and extensions of the network (new substations, changes to the network, etc.).

Input and validation of the data is performed in the source database, so that current online data and online system operations remain unaffected. Once entered, prepared and checked, the modified set of data can then be activated in the operational database at a time convenient to the operator. Activation means the takeover of modified data from the source database to the operational database, without interruption of system operation and without losing any manually entered data. Data activation is coordinated automatically with all other subsystems, servers or activities of a Spectrum Power control system.

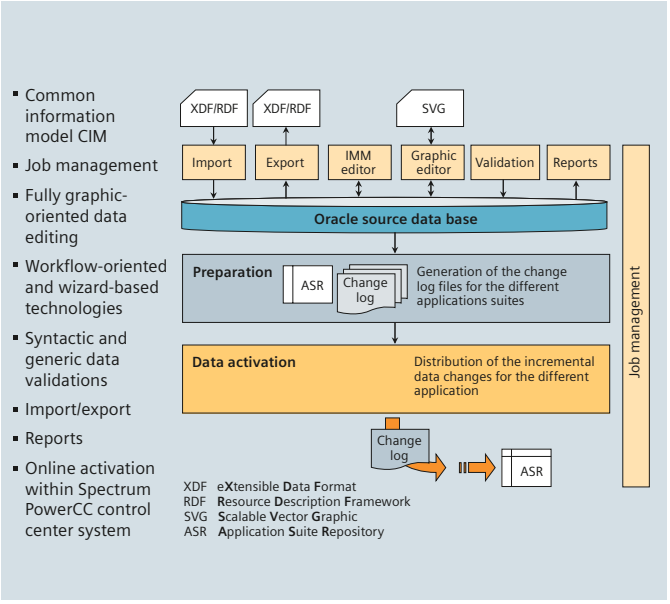


Fig. 7.2-4: **Functional overview of IMM**

After activation, newly entered data (e.g., status information, analog values, station feeders, entire stations) can immediately be called up and displayed by the operator.

Modifications that are recognized later as erroneous can be corrected by an UNDO function, because all modifications carried out in the database are automatically recorded in a built-in database change log. Several levels of security-checking functions provide an audit trail for all data changes in the database and guarantee data consistency throughout the entire system.

An integral part of the user interface is the graphics editor. This editor is used to build and maintain the graphic displays used in the system.

All single-line displays of the Spectrum Power control systems are world-maps. A worldmap is a two-dimensional (2D) graphical representation of a part of the real world. Each point in a worldmap is defined by a pair of unique X, Y coordinates (world coordinates). A worldmap is divided into a set of planes. Each plane covers the complete 2D area including the whole range of the unique world coordinates. The first plane is visible over the entire worldmap magnification range. Any other plane is visible within a certain magnification range only, and contains different graphic representations of the technological (real) objects (e.g., plane 2 shows the substation state, plane 3 shows the summary state of the main feeders, plane 4 shows the single-switching states and so on). Planes can overlap magnification ranges of other planes.

IMM provides standardized interfaces for import and export of source data (fig. 7.2-4). Network data and facility data, as well as graphic data, can be imported or exported via these interfaces. The ability to import large or small amounts of data is supported for the purpose of major or minor system updates and the initial loading of the database (bulk loading). The following functions are provided:

- Single point for all data changes. Avoids the necessity of redundant data maintenance within multiple systems and locations
- Manual data entry or by incremental or bulk data import
- Workflow oriented views on existing, modified or new data
- Multiple and simultaneous data entry sessions of different users on different Spectrum Power user interface consoles
- CIM-compliant data model allows easy incorporation of future information types
- Lifecycle management for planned data modifications
- Data structure version management and automatic data model archiving facilities provides a history of changes as well as an outlook to the planned model at a certain time in the future to reflect the evolutionary nature of models
- Automatic change detection
- Automatic and on request data validation provides information consistency and secures the integrity of the model
- Activation of data modifications without impact on Spectrum Power runtime system
- Automatic Spectrum Power system wide dissemination of data modifications
- Role-based security features and audit records
- Instance-level access rights provide clear responsibilities within the whole data model
- Display (worldmap) editing and automatic generation of displays based on the topology of the network models
- Report generation
- Hierarchical Model Management supports data maintenance and exchange of modified data in a system of hierarchically arranged control centers in an automated way to prevent model inconsistencies between or within organizations

User interface
The user interface of the Spectrum Power control system provides powerful functions to ensure an overview at all times and to permit fast and easy switching between views across all worldmaps. The user interface allows the user to operate the networks and power plant efficiently and permits the administrator to maintain the database and system parameters. The system uses static and dynamic display elements to display the network structure and network state. The user interface provides means for guiding the operator to the workflows, e.g., by checking the plausibility of switching actions after each operating step. Multi-screen operation using drag and drop supports the operator in having a good overview of the power system and in accessing the required equipment in a fast and comfortable manner (fig. 7.2-5).

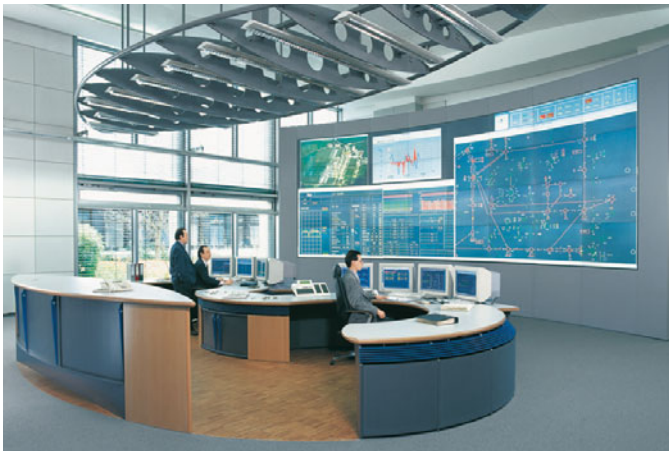


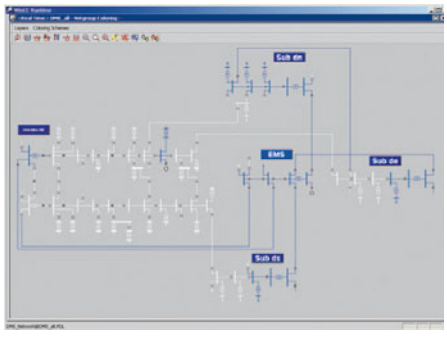
Fig. 7.2-5: **Typical control room environment**

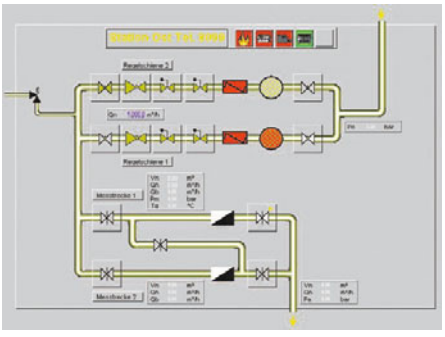
- **All outages at a glance**
- **Easy access to outage details**
- **See what others do (roadwork, construction ...)**
- **Crew position**
- **Information about lightings**
- **Address search**

Spectrum Power map portal is the flexible platform for presenting geospatial control center data to corporate users. It is the link between Spectrum Power control systems and Google Maps and provides

- A Web-Server for embedding Google Maps into corporate web sites
- An optional database system for joining information from different resources, like
  – Spectrum Power
  – Outage Management Systems
  – Archiving Systems
  – Workforce Management Systems
  – ...
- Interfaces for
  – Invoking Google Maps displays from Spectrum Power on-line diagrams and cartographic displays

Fig. 7.2-6: **Sample visualization of outages**





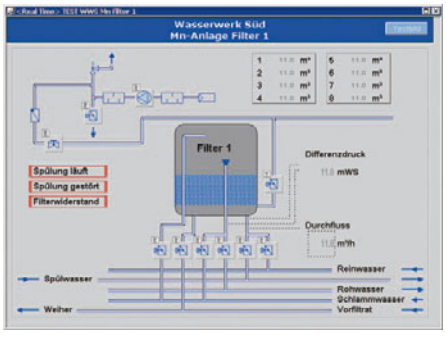


Fig. 7.2-7: **Samples for network displays of electrical, gas and water networks**

Communication front end
The remote terminal interface of Spectrum Power is the Communication Front End (CFE). It is part of the control center system and communicates with the other Subsystems of a Spectrum Power control system via the local area network (LAN). CFE has direct access to the Remote Terminal Units (RTU) of various manufacturers. The control center system is connected to the substations or power stations through these RTUs, which transmit process data of the power supply system. The data is preprocessed by the CFE, which exchanges data with the RTU, preprocesses data in real time and monitors and controls the system, including redundant components.

CFE supports different connections of remote terminal units as point-to-point, multiple point-to-point and multi-point. The transmission can be spontaneous, cyclic, periodic or scanned. The process interface is able to process several protocols such as IEC 870-5-101 or the metered value protocol IEC 870-5-102. Substation equipment (RTUs, submasters) having a TCP/IP Interface according to the standard IEC 60870-5-104 may be connected via a WAN link directly to the CFE-LAN. Both dual channel connections and multi-channel connections are possible (fig. 7.2-8).

The following data are implemented in the process data preprocessing:
- Detection of state changes with image maintenance (old/new comparison of Status messages; forwarding only on change)
- Intermediate position suppression (parameterizable monitoring time)
- Plausibility check of all numeric values (error message on invalid data or limit violations)
- Threshold value monitoring of analog values (passed on only if a parameterized threshold value is exceeded)
- Measured value smoothing (parameterizable filtering function)
- Resultant value formation from raw values using specific characteristics
- Renewal check of cyclically transmitted values
- Information type conversion for raised/cleared indication and transient indications
- Time processing and time synchronization. The CFE server regularly receives the absolute time. The substations are synchronized via time signal transmitters or by protocol specific synchronization telegrams. All information is kept internally with a resolution of 1 ms.
- Monitoring of remote terminal units, communication connections and system components

Communication between Control Centers with ICCP and ELCOM
The necessity of process data exchange between control centers, often from different vendors, is increasing worldwide. Examples are hierarchical control centers, the interconnection of networks, energy exchange between suppliers or the use of external billing systems.

Defacto standard protocols for communication between control centers have been established, e.g., ELCOM-90 or ICCP. The ICCP protocol was defined as an international standard (IEC 870-6 TASE.2) and is now widely accepted and used all over the world.

The Inter-Control Center Communication Protocol (ICCP) is designed to allow data exchange over wide area networks (WANs) between a utility control center and other control centers. Examples of other control centers include neighboring utilities, power pools, regional control centers and non-utility generators. Exchanged data may include cyclic data, real-time data and supervisory control commands such as measured values and operator messages.

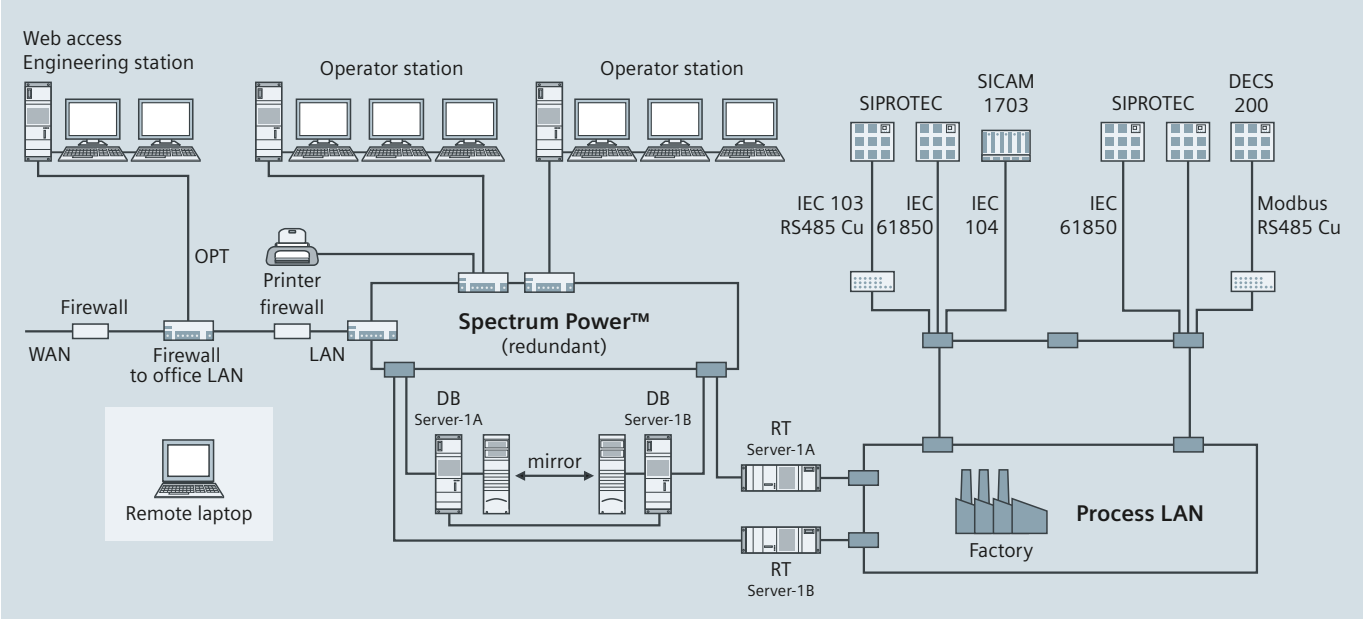


Fig. 7.2-8: **Sample hardware-configuration of a power control system**

Data exchange occurs between a SCADA/EMS server of one control center and the server of another control center. The ICCP server is responsible for access control when a client requests data. One ICCP Server may interact with several clients.

Access control of data elements between control centers is implemented through bilateral agreements. A bilateral agreement is a document negotiated by two control centers that includes the elements (that is, data and control elements) that each is willing to transmit to the other.

The ICCP data link supports a redundant configuration utilizing dual communication servers in active and standby mode. A redundant configuration supports two physically separate paths between the Spectrum Power control systems and the remote system to provide backup in the event that the primary data path becomes unavailable.

Historical Information System
Storage of process data and processing of historical data is an important basis for various power control system functions (fig. 7.2-9 and fig. 7.2-10):

- Historical data allows trending and general data analysis
- Forecast applications (for example load forecast) need a consistent set of historical data as input
- Historical data allows post mortem analysis for example in case of disturbances
- Reports and audit trails are generated from historical data
- Historical data is used to restore past scenarios as input for studies (for example power flow studies)
- Historical data is also an important input to asset management (for example monitoring of equipment maintenance cycles).

Analog values, accumulator values and calculated values (for example state estimator results) can be stored in the Historical Information System as well as status information and messages (for example alarms).

The data to be archived is collected from SCADA and applications (for example state estimator). The data can be collected either spontaneously or at a configurable cycle. Based on the stored data, the Historical Information System provides aggregations (minimum, maximum, average, integral, sum) and calculations. Missing or incorrect data can be entered or updated manually.

The online part of the Historical Information System provides the historical data for immediate access. The retention period for this online part is configurable (typically 1 to 3 years). Historical data that exceeds this retention period can be stored to and reloaded from the so called long term archive.

Multi-site operation of control centers
With the multi-site operation subsystem in Spectrum Power, the operator is provided with a powerful tool for optimizing operation management. It is possible to transfer network management partially or wholly from one control center to another. Emergency concepts can thus be designed and implemented effectively. Such a capability provides for greater reliability of the system (emergency strategies) and makes a considerable contribution to cost reduction. The multi-site control centers can be configured from two or more control centers and permit a very flexible and dynamic system. In the event of failures, each system continues to work autonomously. After recovery of the communication link, the data is automatically updated.

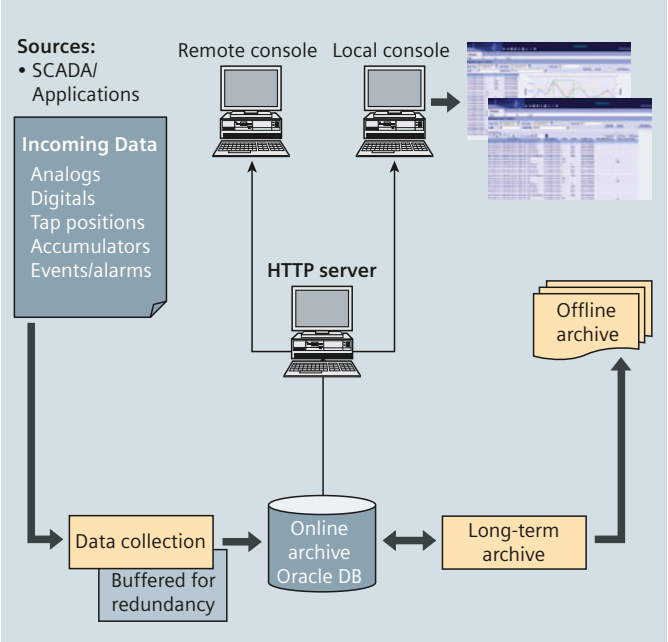


Fig. 7.2-9: **Archiving with the Historical Information System**

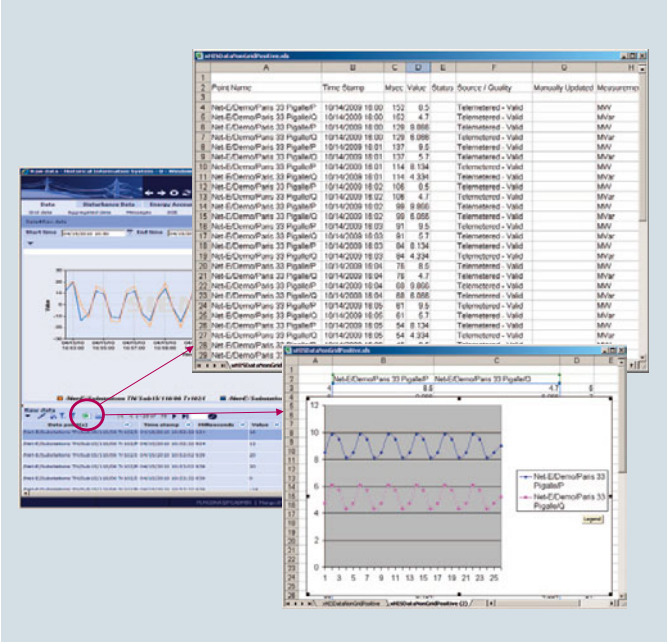


Fig. 7.2-10: **Different views on archived data with the Historical Information System**

Energy Accounting
Energy Accounting (EA) provides the capability to collect, edit and store generation, interchange and other energy values on a periodic basis. These energy values are processed from accumulator data collected from the field and monitored by SCADA. EA also performs various aggregate calculations such as the inadvertent energy, calculations of energy values over multiple time periods (e.g. hourly, weekly, monthly, yearly), etc. for reporting and billing purposes. EA provides extensive editing support such as keeping track of original value, changed value, time of change, author of change, etc. for auditing purpose.

Load Shedding
The load shedding application automatically performs load rejection or disconnection of parts of the network in the event of certain faults and emergencies in order to maintain system stability. It analyzes the state of the network, detects significant events, defines the load to be shed and prepares the required switching actions. The emergency strategies can be configured individually. Depending on the customer requirements, a configuration can be selected from a simple manual solution to a fully automatic system for dealing with faults and emergencies. The following strategies are possible:
- Manual load shedding
- Rotating load shedding (generation shortage for extended time)
- Equipment overload load shedding (delay/avoid tripping of equipment)
- Balancing load shedding (import target deviation, islanding)
- Under-frequency load shedding (system stability).

Power control applications
The aim of the Power Applications (PA) is to support frequency control, i.e. the power system stability (equilibrium between generation and demand), whilst maintaining an optimum generation dispatch and scheduled interchanges across the power system interconnections. The power applications support single area control, multiple autonomous area controls and hierarchical area control configurations. To enable this real-time process the power applications provide several functions:

Load Frequency Control (LFC)
LFC provides control mechanisms that maintain equilibrium between generation and demand in real-time. At the hart of LFC is a PI-controller that, combining actual generation, interchange and frequency, calculates the deviation from equilibrium, referred to as the area control error (ACE), and sends accordingly correction signals to the (single, groups of, virtual, etc.) generating units participating to this regulation process to maintain or restore equilibrium. The corrections will be calculated to meet numerous generation unit operating constraints (base/target point, operating and response limits, etc.). LFC will also implement the necessary corrections to satisfy performance criteria defined, typically, by a regulatory body such as NERC in the US or UCTE in Europe (fig. 7.2-11).

In parallel a performance monitoring function will collect all data related to the performance of such an automatic control according to the pre-specified criteria and store this information for reporting as required by the regulatory body.

Production Cost Monitoring (PCM)
The PCM function calculates, typically, the cost of production for monitoring, e.g. deviations from optimum cost, from planned cost, etc. and for recording purpose. In the case of an ISO/TSO the function may be configured to include the regulating cost.

Reserve Monitoring (RM)
RM calculates reserve contributions to reserve from generation and interchanges and compares them to the requirements. The requirements are typically defined by a regulatory body to guarantee continued security of operation following the loss of a generating unit or an interconnection. These requirements are divided in 2 or 3 categories, e.g. spinning, secondary and tertiary reserves, characterized by the response time window in which such reserves can be activated. Reserve can include many types of generation and interchange capabilities. For example, peakers would be included in secondary reserve and load shedding would be included in tertiary reserve.

Economic Dispatch (ED)
ED optimally dispatches generation to meet the net interchange, system load and network losses whilst respecting generation operating limits. Depending on the operating business, i.e. GMS, EMS or ISO/TSO, ED objective will vary from optimizing production and/or regulating costs to optimizing profits. ED will also operates different dispatch modes, each including a different generation set, e.g. online units under AGC control and in economic mode, online units under automatic control and online units under plant control, etc.

Forecasting applications
Forecasting applications are used for predicting the system (i.e. area and customer group) load, water inflow (hydro) and wind as the basis for generation and interchange planning/scheduling. These applications are also used in support of operation as

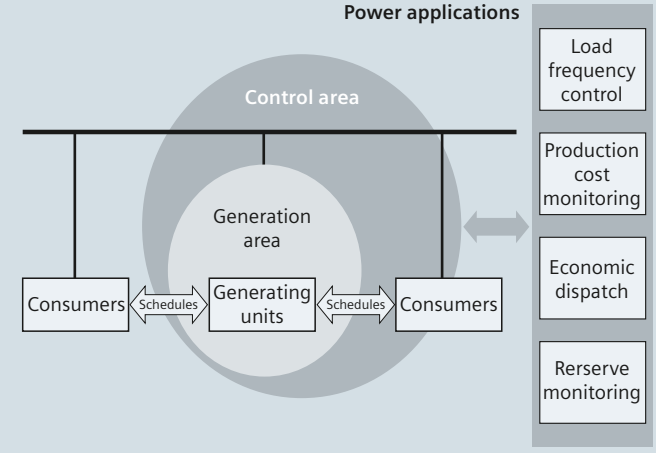


Fig. 7.2-11: **Automatic generation control with power applications**

real-time conditions changes. The load forecast applications further described below supports, besides electricity, also commodities such as water and gas; supports multiple concurrent users and a working forecast environment to allow for review and tuning/adjustments before load forecast is made current for real-time use; and provides for adjustments (e.g. scaling) and tracking mode (i.e. the next few hours of the active forecast are (automatically or on manual request) adjusted based on the observed deviations between the actual measurement and forecast during the last few hours).

Medium-/Long-Term Load Forecast (MTLF/LTLF)
MTLF is used to forecast the load over a period of 1 week up to 2 years whilst LTLF is used to forecast the load over a period of 1 year up to 5 years. The methods used in both applications are processing historical data with multiple regression analysis (one method is based on the ARIMA model).

Short-Term Load Forecast (STLF)
STLF is used to forecast the load over a period of few days up to 14 days in 30-60 minutes increments. The load forecast supports several prediction algorithms (e.g. Similar Day, Pattern Matching, and Regression Analysis) that can be used separately or in user configurable combination and provides the operator with tools to edit the forecast.

Very Short-Term Load Forecast (VSTLF)
VSTLF is used to forecast the load over a 1-2 hour period in short, e.g. 5 minutes, time increments. The method used by VSTLF is based on a neural network algorithm and its use divided in two phases: the training phase and the forecast phase. Training is executed automatically periodically or on request.

Short-Term Inflow Forecast (STIF)
STIF calculates future inflows into a hydrological system. On the basis of this data, the planning function (e.g., hydro scheduling) can calculate the schedule for hydro plant units.

Power Scheduling Applications
The aim of Scheduling Applications (SA) is to optimize the use of individual power plants (thermal, hydro) and external power transactions in such a way that either the total operating cost is minimized or the total profit on energy sales is maximized after taking all maintenance and operational constraints into account.

The scheduling applications use a sophisticated combination of Mixed Integer Linear Programming and successive Linear Programming. Special techniques are applied to consider non-linear effects and speed up the solution process (fig. 7.2-12).

The scheduling applications include:
Resource Scheduler (RO)
Resource Scheduler optimizes either the medium-term generation plan including energy transactions for minimum cost or the medium-term electricity delivery contracts including energy trades for maximum profit subject to optimal use of energy resources (fuels, water, emission, etc.), to maintenance constraints, to emission rights, etc.

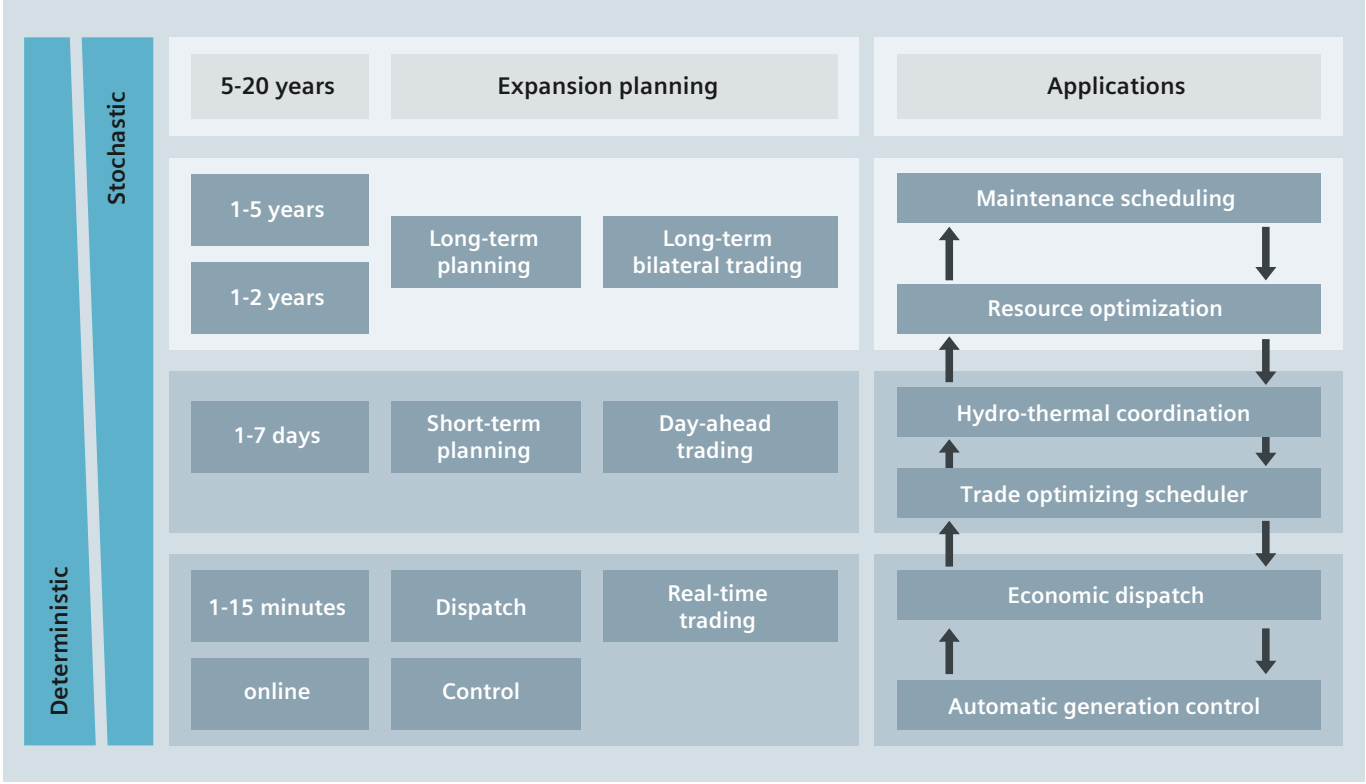


Fig. 7.2-12: **Generation management and planning**

RO determines therefore the optimal generation schedules, the amount of traded energy in bilateral, forward and spot markets, and the corresponding consumption of resources (fuels, emission, etc.).

Generation Scheduler (GS)
Generation Scheduler optimizes the short-term (thermal and hydro) unit commitment & generation plan including energy transactions for minimum cost subject to maintenance, forecasted load, reserve requirement, energy resources (fuels, water, emission, etc.) and emission constraints.

Results (e.g. reservoir levels, accumulated fuel consumption, etc.) from the Resource Scheduler at the end of the short-term planning horizon are used as targets by the Generation Scheduler application.

Unit commitment, hydro scheduling and hydro-thermal coordination are integral part of this application.

Trade Scheduler (TS)
Trade Scheduler is similar to the Generation Scheduler application except for optimizing the short-term traded energy on the spot market for maximum profit.

Results are also similar but for the energy volumes to be bid on the spot market.

Transmission Network Applications
The Transmission Network Applications (TNA) suite provides tools for the advanced monitoring, security assessment and operational improvement of the operation of an electrical transmission network. They are used
- to provide a fast and com prehensible assessment of the current state of the network and improve monitoring by/ beyond SCADA
- to assess the security against faults & outages
- to provide preventive/corrective measures against planned/ existing events
- to optimize operation against costs & losses

These applications considerably increase operational reliability and efficiency in network management. TNA responds automatically to the many different operational (secure, unsecure, emergency) conditions to provide the appropriate support the operator. The application suite will execute, in real-time, periodically, on events and on operator request as a configurable sequence (fig. 7.2-13). Among many other features, TNA also supports study mode allowing concurrent users to execute different studies including preparing corrective strategies, preparing next day operating plan, analyzing post-mortem operational events, etc.

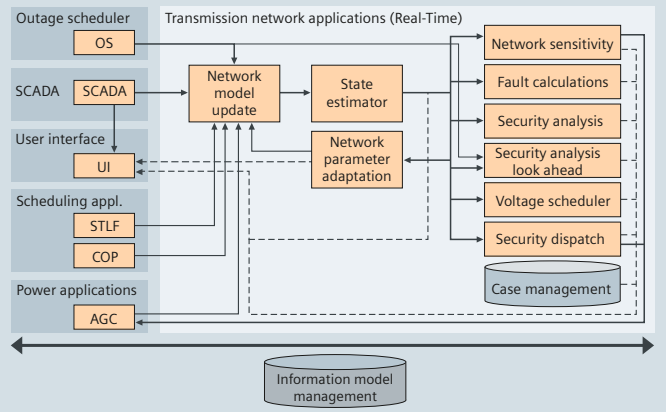


Fig. 7.2-13: **TNA real-time sequence**

Network Model Update (NMU)
The Network Model Update integrates all external and internal information, construct the network topology, and update accordingly the network data required to create the operating conditions to be evaluated by the State Estimator or the Power Flow, i.e.:
- Gathering data from SCADA and other external sources such as AGC, Load Forecast and Outage Scheduler (user options in study)
- Performing topological analysis including identification of electrical island(s), energized/de-energized equipment(s), etc.
- Scheduling accordingly all network loads, generations, regulation settings and limits.

In study mode the retrieval of data is user configurable and offers additional retrieval options typically not applicable in real-time.

State Estimator (SE)
The purpose of this function is to provide a reliable and complete network solution from the real-time measurements, pseudo-measurements (e.g. non-telemetered loads) from model update (MU) and operator entries. The state estimator will identify the observable parts of the network where real-time measurements are redundant. Using this redundancy, the state estimator will identify "bad" measurements, remove them from the valid set of measurements, and then solve for the complete network combining, for the portion of the network that is unobservable, isolated measurements and load, generation and bus voltage scheduled by the MU function. The state estimator will also alarm the operator of any operational limit violations. It will also enable other applications to develop reliable solutions to specific aspects of network operation (e.g. remedial actions against operational limit violations). The state estimator features:
- Orthogonal transformation algorithm
- Measurement consistency check
- Chi-Square test w/ Normalized Residual or Measurement Compensation approach
- Single-pass solution
- Enforcement of equipment limits in the unobservable parts of the network.

Although the state estimator's essential task is to process real-time data, the State Estimator can optionally also be executed in study mode for, for example, post-mortem analysis.

Network Parameter Adaptation (NPA)
The Network Parameter Adaptation (NPA) maintains a time-dependent database of adapted network data used by the network model update to schedule net interchanges, bus loads, regulated voltages, and statuses of time-dependent breakers. NPA adapts these network data in real-time via exponential smoothing using the state estimator results. Then,
- In real time execution, the parameters are used by the model update function to schedule loads and regulated bus voltages to be used by State Estimator as pseudo measurements at unobservable buses.
- In study, the parameters are used by the model update function to schedule loads and regulated bus voltages for the user-specified study day-type and hour. The results are then used by the Power Flow.

Dispatcher Power Flow (DPF)
DPF is used to evaluate the network state under various operating conditions in the present or the future such as, for example, tomorrow's work plan. It is used exclusively in study and typically in conjunction with other applications such as Security Analysis and Optimal Power Flow.

DPF solves either – user selectable – using the Fast Decoupled or Newton-Raphson algorithm. DPF supports, among many standard features,
- Continuous (e.g. Generator) and discrete controllers (LTCs, Capacitors, etc.);
- DC injections and branches (iterative process between DC and AC power flows)
- Area Interchange control, single/distributed slack, MVAr/MW generator curves, etc.

DPF offers plenty of user selectable options for full flexibilit1y of analysis.

Optimal Power Flow (OPF)
The OPF is used to improve the system operation under normal (secure) as well as abnormal (unsecure) conditions by recommending control adjustments to achieve either of the following optimization objectives:
- SECURITY: active & reactive security optimization
- COST: active cost & reactive security optimization
- LOSS: loss minimization
- FULL: COST optimization & LOSS optimization

OPF solves the LOSS minimization using Newton optimization and the other optimizations using Linear Programming. OPF supports, among many standard features,
- Constraint & Control priorities
- Constraint relaxation
  (e.g. long-to-medium & medium-to-short limits)
- Load shedding

OPF offers also plenty of user selectable options for full flexibility in identifying remedial measures to operational violations and/or in optimizing secure operational conditions. Depending on the optimization objectives, the OPF applications can be defined as a reactive power optimization or as an active power optimization.

OPF as described here is used only in study whilst two customized versions described below are provided for real-time use.

Voltage Scheduler (VS)
VS is a real-time application version of the OPF. It determines the optimal use of VAr resources and the optimal voltage profile that should be maintained in order either to minimize operational voltage violations or/and to minimize the network losses. For that purpose, optimal settings of reactive power controls are determined and displayed for implementation.

When the objective is to alleviate voltage violations, minimum shifting of controls from specified setpoints (least-squares shift) is implemented. For that purpose, VS minimizes an objective function consisting of the sum of the quadratic "cost" curves for all control variables. Each such "cost" curve penalizes its related control variable for a shift away from the target value. Weighting of the "cost" curves is performed by a factor specified for each control variable.

Remedial Dispatch (RD)
RD is a real-time application version of the OPF. It determines the optimal use of MW resources and the optimal loading profile that should be maintained in order either to minimize operational overloads or/and to minimize the operating costs. For that purpose, optimal settings of active power controls are determined and displayed for open- or closed-loop implementation. Note that the set of overload constraints can be automatically extended to include branch loading constraints corresponding to critically loaded branches (user specifiable critical loading factor).

Similarly to VS, when the objective is to alleviate overloads, minimum shifting of controls from specified setpoints (least-squares shift) is implemented. For that purpose, RD minimizes an objective function consisting of the sum of the quadratic "cost" curves for all control variables. These "costs" are constructed and handled as described for VS.

Basically, RD provides optimal dispatch similarly to conventional economic dispatch (ED). Compared to ED, however, it is extended to also take into account network loading constraints. This is particularly useful in usually highly loaded systems as well as during exceptional load situations, e.g., due to outages of generating units or transmission lines.

Security Analysis (SA)
The purpose of this function is to determine the security of the power system under a very large number of contingencies (e.g. n-1 criteria). Contingency evaluation in large meshed transmission networks is an exhaustive task because a lot of contingencies (single outages and multiple outages) have to be studied in

order to get a reliable result. On the other hand, usually only very few of the possible contingencies are actually critical, and therefore a lot of computation effort could be wasted. To overcome this difficulty, a two-step approach is used. The two sub-functions of SA are as follows:

- Contingency Screening (CS) provides a ranking of contingencies from the contingency list according to the expected resulting limit violations. For that purpose, a fast power flow calculation (user definable number of iterations) is performed.
- Contingency Analysis (CA) checks contingencies from the ranked list produced by the CS sub-function. For each of those contingencies, a complete AC power flow is performed.

Security analysis supports, among many features,

- user specified contingency and monitored equipment lists
- Single and multiple contingencies
- automatic simulation of contingencies corresponding to the real-time violations
- conditional contingencies
- load transfer and Generator reallocation
- modeling of regulating controllers (LTC, ...)
- contingency screening bypass

Security Analysis Look-Ahead (SL)
Provides the very same function as SA but merges, to the base case, outages from Outage Scheduler that are scheduled within a configurable time window from real-time. SL provides the operator with the security impact from these scheduled outages on real-time operation (which may differ from the conditions used to validate the scheduling of the outage). In case the scheduled outage put real-time operation at risk, the operator can decide whether to cancel the outage, reschedule the outage and/or take preventive measures to allow the scheduled outage to take place as scheduled.

Network Sensitivity (NS)
The purpose of this function is to support calculation and management of loss penalty factors for use by Power Applications (PA) and Scheduling Applications (SA). Penalty factors are used for taking network transmission losses into consideration when dispatching generation whilst minimizing total cost. This NS function is executed automatically as part of the real-time network application sequence. It calculates, for the current network state, the sensitivity of system losses to changes in unit generation and interchanges with neighboring companies. It, then, maintains, using exponential smoothing, a database of such loss sensitivities for a number of system load ranges and net interchange ranges. In real-time mode, NS operates from the network solution produced by the state estimator function, and in study mode from that produced by the dispatcher power flow function.

Fault Calculation (FC)
The purpose of this function is to calculate the fault current and fault current contributions for single fault and multiple faults (user selection). Fault rating violations at and near the fault are provided to the operator. The short-circuit values are compared against all circuit-breaker ratings for each circuit-breaker connected to the faulty bus. Fault current contributions from branches and generating units near the faulted bus are also calculated and may be compared against their respective fault ratings. FC includes, among many features, the effects of mutually coupled lines, the modeling of fault and fault-to-ground impedance and the combination of a fault with a single branch outage.

Operator Training Simulator (OTS)
OTS is based on 4 key components (fig. 7.1-9, section 7.1.1):

- Training management function
- Power system simulation
- Telecontrol model
- Power Control System (copy).

The training management component provides tools for creating training sessions, executing training sessions and reviewing trainee performance. It provides tools to

- initialize the training session, e.g. from real-time or a saved case;
- define the system load profile;
- create event sequences, e.g. a breaker opening, a telemetry failure, etc., that can be either time triggered, event triggered or command triggered;
- create training scenarios, i.e. a number of event sequences, to be activated during the training.

It also provides start/stop and pause/resume functions for the execution of the training session. During the training session it is possible for the trainer to create new events and/or modify the running scenario.

The power system simulation component provides a realistic simulation of the power system behavior to support training from normal operation to emergency operation including islanding conditions and blackout restoration. The simulation is based on a long-term dynamic modeling of the power system including:

- load modeling with voltage & frequency dependency;
- generation modeling with governor, turbine/boiler and generator models;
- frequency modeling;
- voltage regulator modeling;
- protection relay modeling;
- external company LFC modeling.

The telemetry simulation component provides the simulation of the data communication between the power system and the control system. It transfers as simulated field telemetry the results of the power system simulation to the control system copy. And it processes all commands issued by SCADA (operator), LFC, etc. and transfers them to the power system simulation. This simulated telemetry can be modified via the scenario builder by the trainer to reflect measurement errors, telemetry or RTU failures, etc.

This operator training simulator provides a dedicated environment for the trainee (operator) and one for the instructor that

allows the instructor to influence the process in order to force responses from the trainees. The trainee interface is identical with that of the control system so that, for the trainee, there is no difference in functionality and usability between training and real operation.

Distribution management applications
In distribution networks, the telemetry is relatively limited; the fault rate is high as well as the frequency of changes in the network. To meet these requirements, Spectrum Power provides powerful functions with which the operator can operate the distribution network effectively and efficiently.

Fault Management
Fault Management is a set of applications used for locating system incidents and providing fault (or planned outage) isolation and service restoration in distribution networks.

The main Fault Management functionality consists of:
- Fault location
  Locating the faulty section or area of the network as closely as possible
- Fault isolation
  Isolating the planned outage or the faulty section or area of the network
- Service restoration
  Restoring power to de-energized non-faulty areas of the network
- Fault isolation and immediate restoration
  Isolating faulty areas and immediately restoring power to de-energized areas of the non-faulty or isolated network
- Restore to normal or pre-fault state
  Restoring selected number of switches to their normal state or pre-fault state

Fault location, as a part of the Fault Management application, helps to locate permanent faults. Outage faults (for example, short circuits) as well as non-outage faults (for example earth faults) are considered. Fault location is performed by using remotely controlled and manually updated information (communicated by the field crews) from, for example, protection devices and fault indicators. Fault Management localizes the faulty section as closely as possible, based on available real-time data from SCADA and/or field crews.

The isolation function is performed to determine a set of switching operations to isolate an area of the network.

It can be initiated by the location of the faulty segment or area, or by selecting sections directly on the user interface. The purpose is to isolate sections or areas of the network specified by the isolation request to minimize the outage effect on the network.

Service restoration provides a possible choice of switching procedures to restore service. For each switching procedure suggested by the restoration tool, performance indices are calculated based on the network conditions.

Fig. 7.2-14: **View into a large power control center**

The user can select the way of ranking of suggested switching procedures according to one or more performance indices and select the best one for service restoration.

Fault Management switching procedures are typically transferred to a Switching Procedure Management (SPM) application for further processing, that is, edit, review and implementation.

Fault isolation and service restoration can also be used for sections isolation due to maintenance work.

Outage Management (OM)
is a collection of functions, tools and procedures that an operator/dispatcher uses to manage the detection, location, isolation, correction and restoration of faults that occur in the power supply system. OMS is also used to facilitate the preparation and resolution of outages that are planned for the network. These processes are used to expedite the execution of the tasks associated with the handling of outages that affect the network and provide support to operators at all stages of the outage life cycle, starting from events such as the reception of a trouble call or a SCADA indication of an outage and extending until power is restored to all customers. This process is used to solve the outage regardless of whether the outage is at the level of a single distribution transformer providing power to one or a few energy consumers, or at the level of a primary substation providing power to many energy consumers. All operations, authorizations and comments that occur in these processes are documented and collected in outage records. This information is made available to external sites for further statistical analysis and processing. QMS provides the automatic processing of an outage record used to monitor changes in the network and has an internal interface to the crew management or switching procedure management. OMS also provides an interface to the external trouble call systems and an SQL interface (fig. 7.2-14).

Switching Procedure Management (SPM)
allows the operator to create, edit, select, sort, print, execute and store switching procedures. Entries in a switching procedure can be created manually by recording the operator's actions in a

Simulation mode, by modifying an existing procedure or by recording the operator's actions in real-time mode or automatically by applications such as FISR and the OMS system. The switching procedure management capabilities can be used to prepare, study and execute clearance operations. It can also be used to execute switching operations to alleviate fault conditions and to restore power following a fault, as well as to optimize the network operation. SPM provides management capabilities via summary displays and easy-to-use menus.

Crew Management (CM)
This system provides convenient access to the information necessary to track, contact and assign work schedules (outage records) to the field crews of a Utility. The information consists of data such as crew name, work assignments and locations.

Trouble Call Management (TCM)
This system provides convenient access to the information necessary to track, contact and assign work schedules (outage records) to the field crews of a utility. The information consists of data such as crew name, work assignments and locations.

Distribution network applications
The distribution system network applications (DNA) provide fast and comprehensive analysis and optimization of the current distribution network state (fig. 7.2-15). The Distribution System Power Flow (DSPF) calculates voltages (magnitudes and angles) for all nodes (busbars), active/reactive powers for slack buses, and reactive power/voltage angles for nodes with PV generators. All other electrical result values are calculated from the node voltages and branch impedances/admittances after DSPF is solved. The most important result values are flows (powers kW / kVArs and currents A) through lines and transformers, and active and reactive power losses that allow to detect potential limit violations.

DSPF is used to calculate the network statuses under different load conditions and configurations:
- Calculate the actual state of the distribution networks using real-time measurements and the current topology
- Calculate the state of the distribution network in the near future (look-ahead) with actual topology but load values of the given time
- Study the state of the distribution network in the near future with different topology (i.e. according to planned maintenance) and the load values of the given time

Distribution System State Estimator (DSSE) provides a solution for monitoring the actual operating state of the network and to provide a complete network solution for further analysis, for example, optimization of voltage profile.

DSSE provides the statistical estimates of the most probable active and reactive power values of the loads using existing measured values, switching positions, and initial active and reactive power consumption of the power system loads.

The initial active and reactive power values of the loads are provided by static load curves or load schedules (generated based on load curves and measured values/meter readings). Further DSSE estimates the real-time network operating state using measured values.

DSPF and DSSE can handle both symmetrical balanced as well as unsymmetrical unbalanced distribution systems.

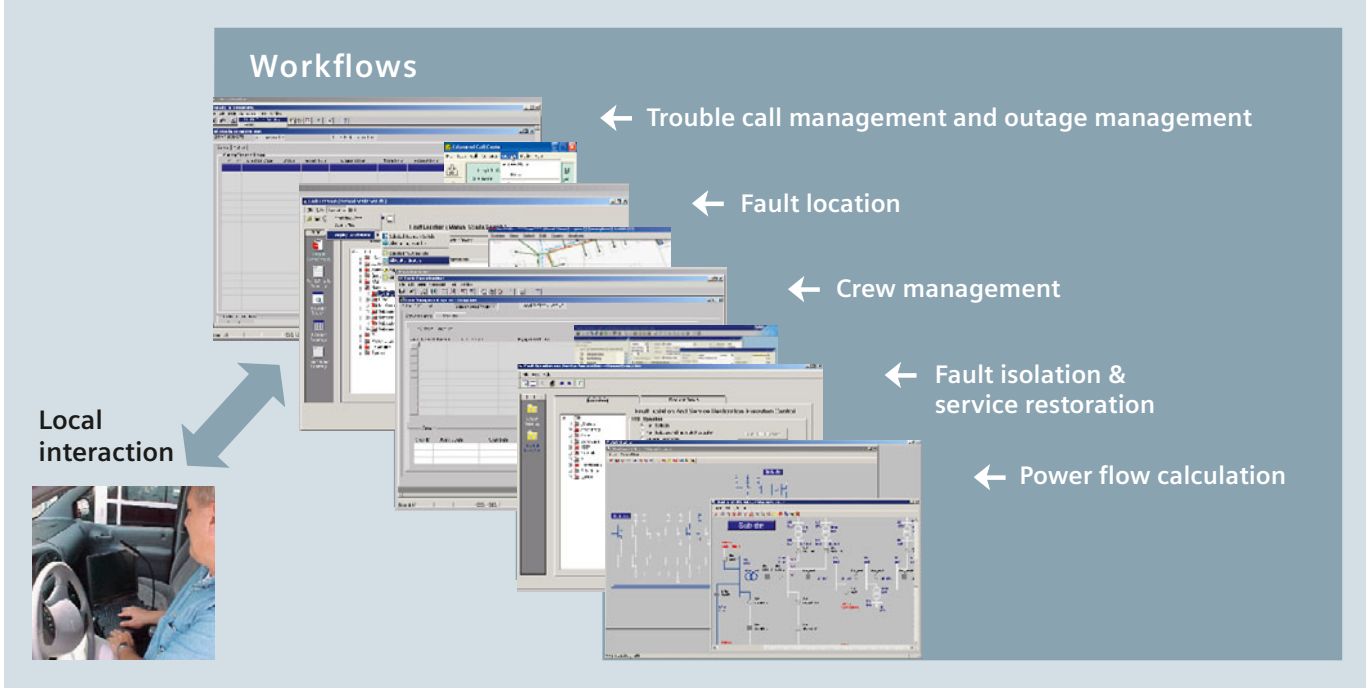


Fig. 7.2-15: **A typical workflow in managing the distribution grid**

The results of DSPF/DSSE are presented on network diagrams and in tabular displays.

Short Circuit Calculation (SCC)
This application helps operator to detect possible problems regarding short circuits, to check capability of circuit breakers and to check if earth fault currents are within the limits. Based on the results and warnings of SCC, the user can initiate or reject changes of the network topology.

SCC solves symmetric or asymmetric faults in symmetrical balanced as well as in unsymmetrical unbalanced distribution networks. The SCC function is used to determine:
- The maximum shortcircuit current that determines the rating of electrical equipment (normally a circuit-breaker for real-time SCC)
- The minimum shortcircuit current that can be a basis for the protection sensitivity checking or fuses selection
- Fault current calculation at selected locations

The following fault types are supported, and each of them may contain fault impedance and/or earthing impedance, depending on user requirements:
- 3-phase faults without earth (ground) connection
- 3-phases faults with earth (ground) connection
- 2-phase faults without earth (ground) connection
- 2-phases faults with earth (ground) connection
- 1-phase to earth (ground), with or without earthed neutral point

SCC can be started on demand to calculate a single fault and can run in screening mode. In screening mode, SCC checks breaking capability, protection sensitivity and earth fault current for a selectable area or the entire distribution network.

The results of SCC are presented on network diagrams and in tabular displays.

Voltage/Var Control (VVC)
calculates the optimal settings of the voltage controller of LTCs, voltage regulators and capacitor states, optimizing the operations according to the different objectives. The following objectives are supported by the application:
- Minimize distribution system power loss
- Minimize power demand (reduce load while respecting given voltage tolerance)
- Maximize generated reactive power in distribution network (provide reactive power support for transmission/distribution bus)
- Maximize revenue (the difference between energy sales and energy prime cost)
- Keep the system within constraints

System operational constraints such as line loading and consumer voltage limits are automatically accounted for in terms of penalties. VVC supports three modes of operation:
- Online mode
  The purpose of this mode is to provide an optimal solution that conforms to the desired objective function.
- "What if? "VVC studies online
  The purpose of this mode is to provide an optimal solution that reflects the current Status of the distribution network with the actual topology but with different loading values.
- Study VVC
  The purpose of this mode is to allow the user to execute short-term operational studies, with different topology and different loading values.

The output of VVC application includes the switching procedure for implementing the solution and the values of the objective functions before and after optimization. In online mode, VVC supports both open-loop (VVC proposes switching actions) as well as closed-loop (VVC actually initiates switching commands to implement the solution). Results such as flows, currents, voltages and losses are displayed on network diagrams and tabular displays.

Optimal Feeder Reconfiguration (OFR)
The objective of this application is to enhance the reliability of distribution system service, power quality and distribution system efficiency by reconfiguring the primary distribution feeders. OFR performs a multi-level reconfiguration to meet one of the following objectives:
- Optimally unload an overload segment (removal of constraint violations)
- Load balancing among supply substation transformers
- Minimization of feeder losses
- Combination of the latter two objectives (load balancing and loss minimization), where each objective is included in the total sum with a user-specified or default weighting factor

System operational constraints such as line loading and consumer voltage limits are automatically accounted for in terms of penalties. OFR supports two modes of operation: In online mode, the application uses the existing real-time measurements and the current topology. In the study mode, the operator can simulate short-term operational studies with different topology and measurements. The output of OFR application includes the switching procedure for reconfiguration and the values of the objective functions before and after reconfiguration.

Optimal Capacitor Placement (OCP)
The objective of this application is to optimize the placement of capacitors – optimal positions (busbars), optimal regulator positions and optimal sizes of capacitor banks are considered.

OCP can optimize the placement of mobile capacitors for planned and unplanned outages as well as fixed capacitors. When determining the busbars on which capacitor banks should be placed, the sizing of capacitor banks and the positions of capacitor bank regulators, OCP considers minimization of active power losses as well as power factor limits and voltage limits. OCP runs on user request.

The results of OCP are displayed in network diagrams and tabular displays.

Distribution Security Analysis (DSA)
The objective of this application is to see the influence of faults (unplanned outages) as well as planned outages on the security of the distribution network.

DSA assesses
- N-1 security in all meshed parts of the distribution network
- Security of simplified restoration procedures based on the current reserve
- Security of reconfiguration scenarios (back-feed, coupling of substations, etc.)
- Security of pre-defined restoration procedures
- Security of scheduled switching procedures

DSA simulates single, multiple and cascading/conditional faults as well as outages of distributed generation.

Expert system applications
The Spectrum Power expert system supports the operator in solving critical and complex tasks in the field of network operation and disturbance analysis (fig. 7.2-16). Spectrum Power expert system applications provide two functions, an intelligent alarm processor (IAP) and an expert system for Advanced Network Operation (ANOP).

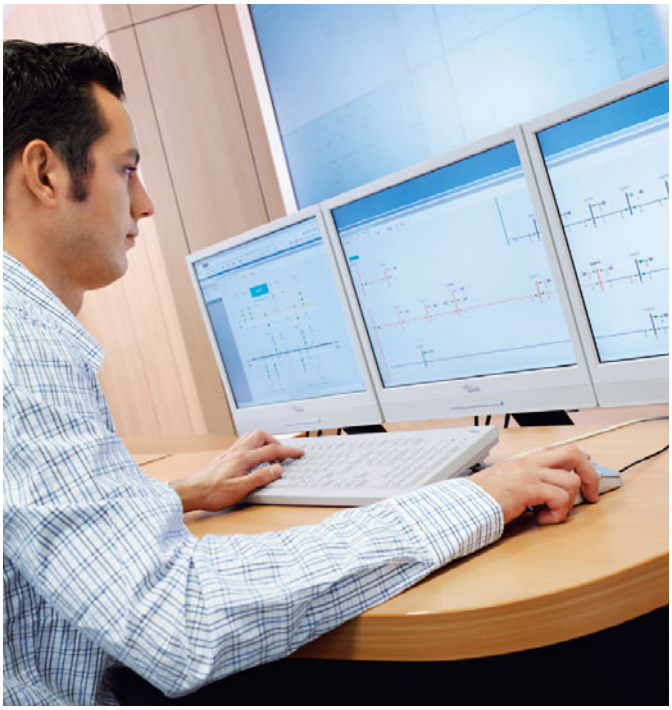


Fig. 7.2-16: **The Spectrum Power expert system supports the operator to solve critical and complex tasks**

The IAP provides information about the fault location in case of a network disturbance. It is based upon a hierarchical, multi-level problem-solving architecture that combines model-based and heuristic techniques, and works with an object-oriented data structure. Within the diagnosis, the IAP determines the location and the type of disturbances in electrical networks, e.g., fault within a transformer. The model used by the IAP corresponds to the model of the protection system. This provides the additional advantage of monitoring the correct operation of the protection system. The diagnosis results are displayed in the XPS report list.

Advanced Network Operation (ANOP)
This system supports the following network operations of the operator:
- Automatically triggered operations for:
  - Automatic fault isolation and restoration
  - Automatic removal of overload
- Manually triggered operations for:
  - Manual fault isolation and restoration (trigger fault)
  - Planned outage (take out of Service)
  - Load relax
  - Resupply (energizing)

The algorithm of ANOP manages all types of distribution networks – for cities or provinces, small networks or large networks – with radial configurations and also with looped configurations. It can be used in telemetered networks as well as in non-telemetered networks. The algorithm is fully generic, considers the actual network status (topology, values, tagging), and provides an authentic and extensive solution for the given task, taking into account all electrical and operational requirements. The algorithm develops the best strategy for the given situation and considers all necessary steps to reach a solution that fulfils the task in a secure, complete and efficient way.

With the help of the built-in power flow, each step is checked; tagged equipment is respected. The proposed solution changes the actual topology of the network in a minimal way. In the exceptional case in which a complete solution is not available under the actual circumstances, a partial solution is evaluated, again taking into account all electrical and operational requirements. The results are displayed in the XPS report list and in the XPS balance list, and a switching procedure is created and inserted in the switching procedure management.

7.2.2 Common Model Management System (CMMS)

In parallel with the liberalization of the energy markets, there is an ever-increasing need for data sharing, not just to serve the own enterprise, but also to respond to needs from outside entities. Sometimes this need is driven by industry entities. Sometimes, and lately more than others, this need is driven by industry requirements passed by governing bodies such as NERC and FERC.

Siemens has been alert to the need for common modeling language and integration platforms for optimizing the benefit also to smart grid implementation across the power delivery network. In developing the first product of its kind, the Common Model Management System (Spectrum Power CMMS), Siemens has compiled within a single data model both planning and operations network models for both transmission and distribution and presents model editing and tracking on a time-synchronized basis – allowing a model of the system to be derived for any point in time in the future or history, in either a planning or an operations protocol.

Siemens is now changing the mindset of modelers from thinking in terms of traditional network models where individual assets properties are aggregated into a larger component in the model (i.e. wave traps, underground cable segments, overhead line segments are all aggregated into one "transmission line" in the network model – resulting in the individual assets loosing their identity) to terms of the network really being a series of interconnected assets. This transitional thinking results in significant reliability, efficiency and resource optimization.

The Siemens Spectrum Power CMMS provides tools and automation to efficiently manage the exchange, validation, approval, and commissioning of transmission network model changes within and between RTO/ISO and Transmission Distribution Service Provider (TDSP) operations and planning departments. CMMS enables generating, managing, and synchronizing network model information from a single shared source to support utility systems and applications, such as network planning, energy management, market operations, congestion revenue rights, outage scheduling and more. CMMS also provides a foundation for smart grind information management. The CIM-based architecture provides a unified model, auditable model change records, approval levels for model changes, as well as rich model documentation capabilities. It allows chronological model tracking in a fully open environment allowing all applications to share services and data. This greatly reduces modeling errors, improves coordination, and streamlines processes for transmission network changes. This enables exchanging information on a level far above the paper or file exchanges that are in use to day.

The CMMS integrates Spectrum Power Information Model Manager (IMM) and Siemens Model on Demand (MOD) products into a single package. The IMM generates and maintains the operations network model changes, while MOD tracks the planning model and all planning changes. The integrated package provides consistent, coordinated models for any point in time based on the planned energization dates provided to the system (fig. 7.2-17). Point of time models can be exported to most popular applications using CIM (IEC 61970 and IEC 61968) and CIM for planning and dynamics international standards.

The key features and capabilities are:
- Industry standard CIM-based model representation
- Synchronized chronological model tracking from future to past horizons
- Single model integration of planning, engineering, operations, market, etc.
- Electronically submit network model changes to facilitate exchange between the RTO/ISO and the regional TDSP.
- Develop a planning model for the RTO/ISO combining the current regional operating model with the region's proposed plans. This model can be used as the basis for evaluating network reliability as network changes are implemented over time.
- Electronic Approval/Rejection Notification provides electronic notification to the TDSP when a plan is approved or rejected. If the plan is rejected, it identifies the reasons so the TSDP can modify and resubmit the plan in a timely manner.
- Approved plans are placed in a secure accessible repository. The TDSP can access its approved plans from the repository and use these to develop the commissioning plan necessary to put them into operations.

Managed changes between planning and operations within the TDSP provides streamlined electronic coordination of planning model changes to be commissioned with the real-time operating model.

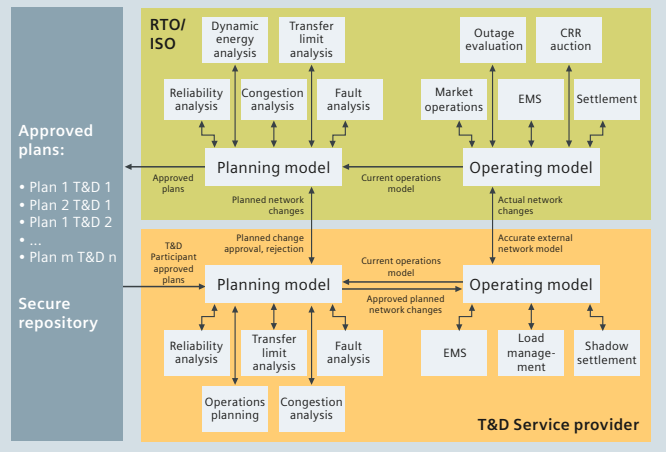


Fig. 7.2-17: **Common Model Methodology**

7.2.3 Decentralized Energy Management Systems (DEMS)

In parallel with the liberalization of the energy markets, the decentralized generation of electrical power, heat and cold energy becomes more and more important. The generation of these types of energy near to the consumers offers economical and ecological benefits. In this context, interest is directed to so-called virtual power plants. A virtual power plant is a collection of small and very small decentralized generation units that is monitored and controlled by a superordinated energy management system. In general, these generation units produce heating and cooling energy as well as electricity (fig. 7.2-18).

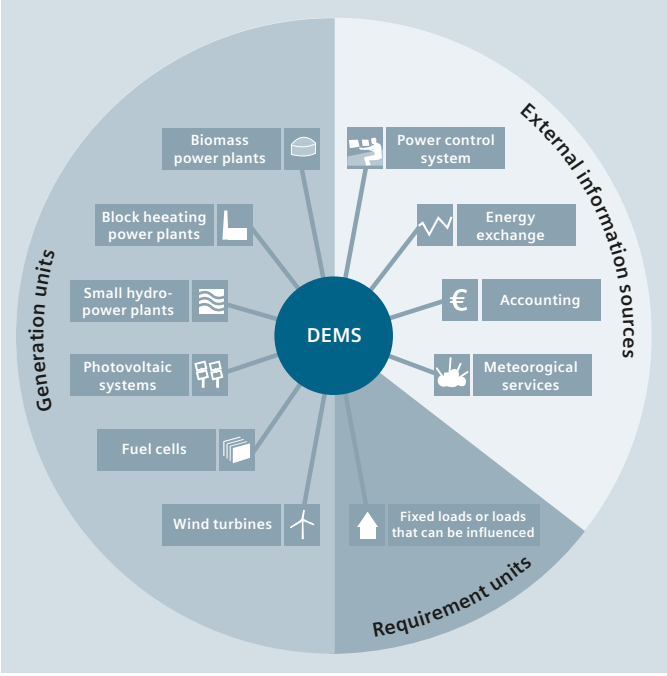


Fig. 7.2-18: **Elements within de-centralized energy management**

A successful operation of a virtual power plant requires the following technical equipment:

1. An energy management system that monitors, plans and optimizes the operation of the decentralized power units

2. A forecasting system for the loads that is able to calculate very short-term forecasts (1 hour) and short-term forecasts (up to 7 days)

3. A forecasting system for the generation of renewable energy units. This forecast must be able to use weather forecasts in order to predict the generation of wind power plants and photovoltaics

4. An energy data management system which collects and keeps the data that is required for the optimization and the forecasts, e.g., profiles of generation and loads as well as contractual data for customer supply

5. A powerful front end for the communication of the energy management system with the decentralized power units

First, a virtual power plant needs a bidirectional communication between the decentralized power units and the control center of the energy management system. For larger units, conventional telemetry systems based on protocols such as IEC 60870-5-101 or 60870-5-104 can be used. In the future, with an increasing number of small decentralized power units, the communication channels and protocols will play a more important role. It is likely that the costly conventional telemetry technique will be substituted by other techniques based on simple TCP/IP adapters or based on power line carrier techniques. Siemens is contributing to the upcoming standard "IEC 61850-7-420 Ed.1: Communication networks and systems in substations – Part 7-420: Communications systems for distributed energy resources (DER) – Logical nodes."

All operation planning and scheduling applications require forecasts with sufficient accuracy. For the characterization of the forecasts, several operating figures are used, such as the average forecast error per day or the absolute error per day or per forecasting time period. Depending on the main purpose of the virtual power plant, the requirements for the forecast methods may change. If the primary purpose is to reduce the peak load or the balance energy, the forecast has to be very exact in the peak time or times with the high prices for balance energy. Furthermore, the forecast algorithms must be able to adapt rapidly to new situations. For example, a virtual power plant operated by an energy service company must be able to consider changes in the customer structure.

Based on the results of the forecast algorithms and the actual situation of the virtual power plant, the load to be covered can be dispatched by using the decentralized power units and the existing energy contracts. This is a complex and recurrent task. Therefore, computer-based methods of operations research are used. This is the most important component in a virtual power plant, because it realizes and uses the optimization leeway.

The special structure of a virtual power plant places high demands on the mathematical models for the optimization. The models must be very precise because rough models could yield optimization results that cannot be realized by the power system. Because the virtual power plant must provide an automatic mode for online control of the decentralized power units, e.g., for compensating the imbalance, no operator can check and correct the results. Furthermore, the optimization leeway can only be used if the optimization package is able to determine the solution cyclically within the settlement period.

Based on the requirements defined in the preceding section, a Software package for decentralized energy management called DEMS was developed. The DEMS system is not meant to be a substitute for all possible automation equipment necessary for operating the components of a virtual power plant. There must be at least that much local automation equipment available to

allow the basic operation of the decentralized power units in order to ensure component and personal safety in the absence of the DEMS system.

The components/units of a virtual power plant and their energy flow topology are modeled in DEMS by some classes of model elements, e.g., converter units, contracts, storage units, renewable units and flexible loads.

The DEMS planning application models all cost/revenue and constraint-relevant energy and media flows, regardless of their type (e.g., electricity, hot water, steam, cooling, emissions, hydrogen).

The DEMS control applications provide control and supervision capability of all generation units, storage units and flexible demands as well as control capability to maintain an agreed-upon electrical interchange energy profile. Fig. 7.2-19 illustrates the modeling of a decentralized power generation system by using DEMS model elements (rectangular objects with unit names), and connecting them via balance nodes (circular objects with node numbers).

The functions of DEMS (fig. 7.2-20) can be subdivided into planning functions and control functions. The respective planning functions are the weather forecast, the load forecast, generation forecast and the unit commitment. Furthermore, DEMS provides generation and load management as an exchange monitor and online optimization and coordination.

The planning functions consider a time period of one to seven days with a time resolution depending on the settlement periods for energy sales and purchases, e.g., 1 5, 30 or 60 minutes. The planning functions run cyclically (e.g., once a day or less frequently), on manual demand and can be spontaneously triggered.

The DEMS weather forecast function provides the forecasted weather data import/calculation that is used as an input for the other DEMS function modules. The weather forecast function has import capability for forecasted (and maybe also historical) weather data provided by external sources like weather forecast Services. If there is local weather data measurement equipment located in the virtual power plant, the external imported weather forecast is adapted to the local site measurements by using a moving average correction algorithm that minimizes the difference of the deviation between the external forecast and locally measured weather data around the actual time step. The resulting internal weather forecast is provided as an input to the other DEMS planning functions.

The DEMS load forecast provides a forecast calculation for multiple load classes. The basic data is the continuous historical measured load data in the time resolution of the planning functions. A piecewise linear model is set up explaining the modeling of the demand behavior as a function of influencing variables such as day types, weather variables or production

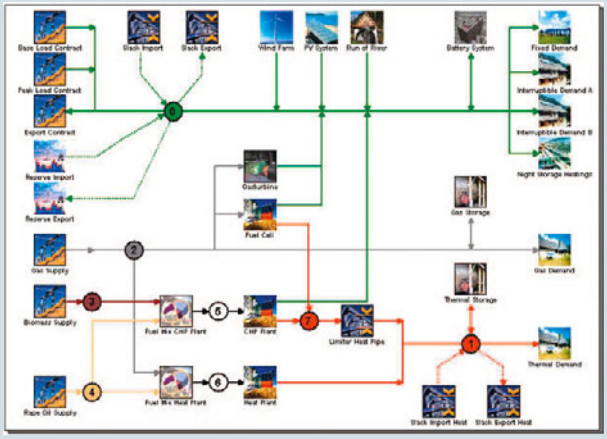


Fig. 7.2-19: **System topology with DEMS model elements (rectangular objects with unit names) and connecting them via balance nodes (circular objects with node numbers)**

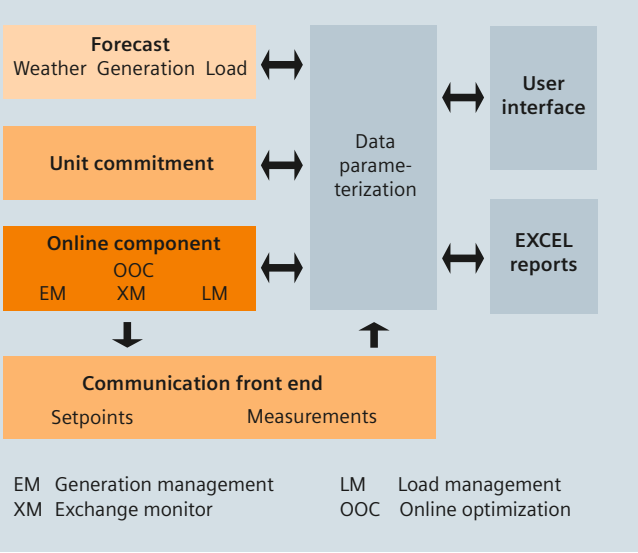


Fig. 7.2-20: **DEMS functions**

schedules from industrial loads. The model equation coefficients are estimated cyclically each day after new measurements are available.

For each time stamp of the day (e.g., 96 time stamps for a 15-minute time resolution), a separate coefficient analysis is done. The data used for the analysis starts from yesterday for a parameterized time range in the past (from 0 to 84 days). The mathematical method for calculating the model coefficients is a Kalman filter. By using the Kalman filter, the definition of fully dynamic, partial static and fully static forecast models is possible.

The DEMS generation forecast calculates the expected output of renewable energy sources dependent on the forecasted weather conditions. The forecast algorithm is a piecewise linear transformation of two weather variables to the expected power output according to a given transformation matrix (e.g., wind speed and direction for wind power units, light intensity and ambient air temperature for photovoltaic systems). The transformation matrix can be parameterized according to the unit technical specifications and/or is estimated on the basis of historical power and weather measurements by applying neural network algorithms (in an offline analysis step).

The DEMS unit commitment function calculates the optimized dispatch schedules (including the commitment) for all flexible units such as contracts, generation units, storage and flexible demands. The objective function is the difference of revenue minus costs, the profit. The scheduling considers the parameters of the model elements and their topological connection, which defines the financial Information, as well as the technical, environmental and contractual parameters and constraints of the virtual power plant. The unit commitment uses mixed integer linear programming to calculate the results of the optimization problem.

The DEMS generation management function allows for the control and supervision of all generation and storage units of the virtual power plant. Dependent on the control mode of the respective unit (independent, manual, schedule or control mode) and the unit parameters (minimum/maximum power, power gradients, energy content), the actual state (start-up, online, remote controllable, disturbed) and the actual power output of the unit, the start/stop commands and power setpoints for the units are calculated and transmitted via the command interface. Furthermore, the command response and the setpoint following status of the units are supervised and signaled. In the event of a unit disturbance, the generation management can start a spontaneous unit commitment calculation to force a rescheduling of the remaining units under the changed circumstances while also considering all integral constraints.

The DEMS load management function allows the control and supervision of all flexible loads in the virtual power plant. A flexible load class can contain one or several load groups of the same priority, where one load group is supposed to be switched on or off completely with one switching command. Dependent on the control mode of the load class (independent, schedule or control mode) and the actual switching state, the actual control state, the actual power consumption and the allowed control delay time of the load groups, the required switching controls to fulfill the overall load class setpoint are calculated and transmitted via the command interface (applying a rotational load shedding of the load groups of one load class). The optimized load class schedules calculated by the unit commitment function are the basis for load class control in the operation modes “schedule” and “control”.

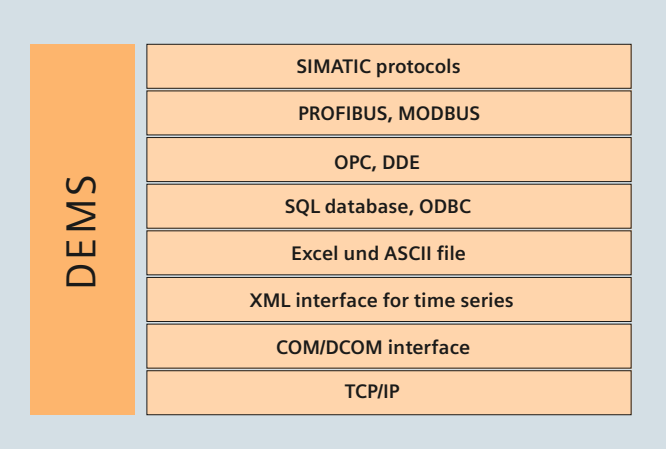


Fig. 7.2-21: **DEMS interfaces**

The DEMS exchange monitor function calculates the expected deviation of the agreed-upon electrical interchange schedule of the current accounting period (15 or 30 or 60 minutes) and the necessary power correction value to keep the interchange on schedule. On the basis of the actual energy consumption of the running accounting period and the actual interchange power trend, the expected energy interchange at the end of the accounting period is calculated. The difference between this value and the agreed-upon interchange value, divided by the remaining time of the accounting period, gives the necessary overall power correction value that is needed to be on schedule with the agreed interchange at the end of the accounting period. This value is passed to the online optimization and coordination function for further processing.

The DEMS online optimization and coordination function dispatches the overall power correction value to all individual generation units, storage units and flexible load classes that are running in control mode. The distribution algorithm works according to the following rules: First, the actual unit constraints (e.g., minimum and maximum power, storage contents, power ramp limitations) must be considered. Second, the overall power correction value should be reached as fast as possible. And third, the cheapest units should be used for control actions. “Cheapest” in this context means that the incremental power control costs of the units around their scheduled operating points are taken as a reference. The incremental power control costs of the individual units are calculated by the unit commitment function along with the respective dispatch schedules. The individual unit’s power correction values are passed to the generation management function and load management function for execution. DEMS is based on widespread software components running on Microsoft Windows-based computers with standardized interfaces and protocols (fig. 7.2-21). This secures the owner’s investment in the virtual power plant, because it is easy to extend the system with new modules.

Fig. 7.2-22 depicts the main components of DEMS. As basic SCADA engine, SIMATIC WinCC (Windows Control Center) is used.

The application algorithms are realized with Siemens ECANSE (Environment for Computer-Aided Neural Software Engineering). A Microsoft Excel interface exists for time series data input and output. The time series data is stored in the process database of WinCC (using a commercial relational database system). DEMS uses CPLEX for solving the mixed integer linear programming problem. By configuring WinCC, ECANSE and Excel files, a concrete DEMS application system can be configured according to the specific structure of the virtual power plant.

The user interface plays an import role in operator acceptance. It must be user-friendly in order to reduce the training effort and to avoid faulty operations. Therefore, the user Interface of DEMS is created using the basis of the WinCC user interface builder (fig. 7.2-23).

In addition to this, for more complex and flexible graphical analysis of time series information, Excel report files for result presentation can be used. By using either a remote desktop software tool or by using the WinCC web navigator option, ISDN or Web-based remote access to the DEMS system is possible. Fig. 7.2-23 shows some examples of the user interface.

As just stated, the interface and protocols of the communication front end are essential for the success of an energy management system in a virtual power plant. Therefore, DEMS provides several interface process data interfaces and protocols:

- OPC
- MODBUS Protocol Suite, MODBUS Serial
- PROFIBUS DP, PROFIBUS FMS
- SIMATICS5, S7, TI
- Windows DDE
- PLC protocols

In addition, DEMS has a SOAP-based XML Web interface that allows data exchange of process values and time series data from DEMS to DEMS or DEMS to Web applications. Furthermore, DEMS allows the import/export of process values and time series data from/to ODBC data sources, Excel and ASCII files.

- Synchronizing T&D and RTO/ISO operating models electronically provides TDSP operating model changes to the RTO/ISO when ready to be commissioned.

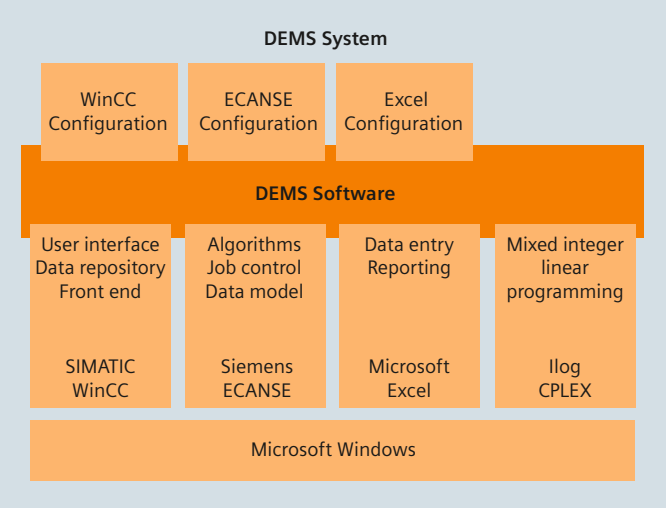


Fig. 7.2-22: **DEMS components**

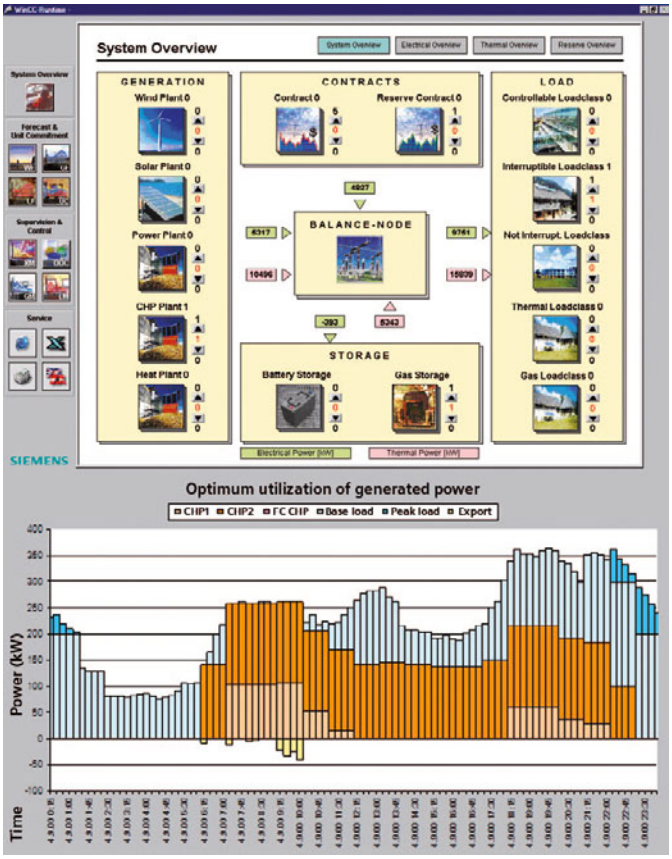


Fig. 7.2-23: **DEMS user interface**