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Stochastic Power System Operation

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Abstract — This paper outlines how to economically and reliably operate a power system with high levels of renewable generation which are stochastic in nature. It outlines the challenges for system operators, and suggests tools and methods for meeting this challenge, which is one of the most fundamental since large scale power networks were instituted. The Ireland power system, due to its nature and level of renewable generation, is considered as an example in this paper.

Index Terms—Stochastic power system operation, security constraints, renewable generation.

I. INTRODUCTION

The Ireland power system is a small, synchronously isolated system, with a peak demand of 7 GW (2009), and based mainly on gas and coal-fired generation. In addition to a target of 40% of total electrical energy from renewable sources by 2020, the main future changes on the power system which need to be addressed from a control point of view are the advent of stochastic generation and the expected change in the constitution of the electrical load, due to increased demand side management and the wide-scale introduction of electric vehicles. This new load and generation mix fundamentally changes the character of the power system, which will be transformed from a system made up largely of synchronous generators, with a predictable demand profile, to a system largely made up of induction generators driven by stochastic sources and a demand which will vary with price signals, with battery loads as one of its major constituents.

Compared to current practice, it is certain that there will be unusual power flows, since conventional generation will be offline or backed off and that the network will be dispatched in a manner which was not originally planned for i.e. increased distributed generation (DG). Thus, for example, fault level and rotor angle stability limitations may occur, due to a concentration of renewable generation in a weak transmission area remote from the load centres.

In order to operate and control this new type of power system, new operational procedures and facilities such as security constrained optimal power flow (SCOPF), which will be capable of dealing with fault level and stability constraints in real-time, will be required since it will not be possible to study all possible operational scenarios ahead of time.

This paper will discuss how the Ireland power system will be constituted in 2020 and how with 40% of its energy requirements being delivered, on average, from renewable sources it can be securely operated and controlled.

II. IRELAND AND 2020

The island of Ireland effectively consists of two separate transmission and distribution networks split between the Republic of Ireland and Northern Ireland. The two transmission networks are connected by a double circuit 275kV and two 110kV transmission lines.

In 2008, the government in the Republic of Ireland specified a target for 2020 that 40% of all electrical energy be produced from renewable sources [1]. A similar 40% target is in review in Northern Ireland. To that end, there is currently 1,260 MW of wind generation connected to the Republic of Ireland grid, with 746 MW connected to the distribution network and the remainder connected to the transmission network. 300 MW of wind generation is installed in Northern Ireland and is connected to the distribution network. The TSO in the Republic of Ireland is EirGrid while the TSO in Northern Ireland is SONI (System Operator for Northern Ireland).

In order to attain 40% renewable energy penetration by 2020 it is estimated that 6 GW of wind generation will be required. A national renewable energy action plan, for the Republic of Ireland, which was published in June 2010, outlines how this target will be achieved. The bases for achieving this target are onshore wind, grid development and the development of a micro generation sector. Wind contributed 11% of annual electricity production in 2008 and its penetration on the island has peaked at 45% on occasions. Figure 1 illustrates the penetration on July 4, 2010 which shows that wind penetration exceeded 40% for a number of hours and 45% on occasions. EirGrid has developed a plan, known as Grid 25 [2] to develop the transmission network for the Republic of Ireland for 2025 including reinforcements to cater for additional renewable generation.

One HVDC interconnection exists between Northern Ireland and Scotland which has a capacity of 500 MW. A second HVDC interconnection between Ireland and Wales is due to be commissioned in 2012. This is also rated at 500 MW. Further interconnections to Europe are under consideration. Almost 60% of current generation is produced by natural gas with coal being the other major thermal generator. There is a minimal amount of run of the river hydro, 220 MW, and a single pumped storage station which is rated at 292 MW.

The Government has set an electric vehicle target of 10%
or 250,000 vehicles by 2020 [3] in order to reduce CO₂ emissions and fuel imports. It has also initiated a smart meter evaluation project [4], involving 7,000 residences in order to study energy efficiency. These two initiatives are also being considered from a system operation point of view for both load management and system flexibility. A number of research programs in these areas are also under way in various institutes including the Electricity Research Centre (ERC) in University College Dublin.

![Figure 1: Wind penetration in Ireland – July 4, 2010](image)

III. OPERATIONAL CHALLENGES

The Ireland power system illustrates today the main issues which many power systems need to address from an operations /control viewpoint i.e. the advent of stochastic generation in the form of solar, wind and wave energy, and the change in the constitution of the electrical loads due to demand-side management (DSM) and demand-side response (DR).

Consider the impact of electric vehicles, and especially their charging profile, and how it will impact on the shape of the system demand curve. They could significantly increase the system demand at the peak period of the day, which could be difficult to supply due to network constraints and insufficient supply, while they could also increase the minimum load at night, which could simplify overnight operations, especially at times of high wind generation.

Additional technical issues which also must be considered include:

- Active and reactive reserves
- Voltage, frequency and rotor angle stability
- Fault current levels, both high and low
- Commitment and dispatch of generating plant at both transmission and distribution voltage levels
- Increased complexity of system management and control
- Forecasting variations in wind, wave, solar and demand
- Operational issues, as yet unknown, related to renewable sources, e.g. a sharp drop in solar output due to passing clouds; the impact of storms on wave power (it is expected that wave turbines will shut down at some threshold); a limit to the number of brake operations on wind turbines
- Cycling and ramping of thermal plant when operating in parallel with renewable generation
- Dynamic feeder ratings which will change with wind speed, direction and ambient temperature
- Possible inertial constraints
- Internal HVDC links in an existing AC network
- Storage, e.g. pumped storage and compressed air energy systems (CAES) - frequency of use and quantity of pumping

The traditional N-1 methodology has been the basis for system design but is it adequate to cater for the new type of power system which is evolving? The N-1 methodology was based on maximum and minimum loads for different times of the year and on traditional flow patterns whereby power flowed from the higher voltage transmission levels, where the large generators are located, to the distribution voltage levels where the load is connected. The timing of stress situations in the future will be uncertain – they will not necessarily be at the peak demand, or during a major transmission or generator outage. In power systems with a high level of renewable generation penetration, the power flows will also change due to the location of generation at distribution voltage levels, leading to a requirement for new operational security standards to be defined.

Distribution networks incorporating generation will become active, with power exchanged between the transmission and distribution networks. This will have a significant impact on power system operation at both levels. As well as altering network operation, the commitment problem could also become confused since the majority of the generators may no longer be at the transmission level. The roles of the transmission system operator (TSO) and distribution system operator (DSO) will now overlap, with, for example, the TSO having to consider the status of the distribution network before committing a generator and the DSO being unable to unilaterally operate a distribution feeder due to the TSO requiring power from a generator on the distribution network. The new paradigm will result in new Energy Management System (EMS) and Distribution Management System (DMS) architectures, which will require much more extensive computing, control and communications capabilities than are allowed for at present.

IV. MEETING THE OPERATIONAL CHALLENGES

In order to meet the operational challenges of the new type of power system, the system operator will need both the necessary analytical tools in the control centre, and an extensive and reliable communications and control system in order to implement decisions.
A. Control Centre Tools

A number of new (or expanded capability) tools may be required to operate a power system with a high penetration of renewable generation. It is not suggested that all of these will be necessary but it must be stressed that connecting high levels of renewable generation will dramatically alter the role of the traditional operator, since the system itself will be subject to far greater daily and intra-hour changes than experienced heretofore.

1) Forecasting

Fundamental, for many of the control centre applications, is weather and load forecasting. Forecasting of ramp events and extreme events, although not discussed further in this paper, will also become more critical.

Accurate weather forecasting is critical for all renewable forms of generation. For example, in the case of solar generation, it may also include the position of clouds relative to solar arrays. Existing wind forecasts are typically fairly accurate for horizons up to 48 hours, but even that is not adequate. Ideally, a five day forecast is required to allow system operators to schedule plant for a week ahead. Such a forecast, as well being accurate on a temporal basis, must also accurately predict on a geographical basis to facilitate operation of the distribution and transmission networks and identify potential network constraints. This issue will become more critical as renewables penetration increases. A further critical aspect of accurate geographical forecasting will be its use in the calculation of feeder ratings. Assuming dynamic feeder ratings are in everyday use, it will be important for all predictive applications to have accurate rating information. Forecasting for solar and wave generation are new areas but will require attention as these technologies develop.

Demand or load forecasting will change significantly from current methodologies. Traditionally, demand forecasting has employed inputs such as weather variables and historical load data. With the advent of new types of loads, such as electric vehicles, demand side management and demand response schemes a new level of complexity will be added to demand forecasting. TSOs may have to model load variations down to medium voltage levels, such as 10 kV, in order to produce reliable forecasts. These forecasts will also need to identify real and reactive components, since provision of reactive support will be a critical part of operating the new power system. Market price signals, and their influence on demand, will also have to be incorporated into new load forecasting facilities.

2) Unit Commitment

Traditional unit commitment (UC) is the problem of determining the schedule of generating units within a power system, subject to device and operating constraints [5]. The decision process can select units to be on or off, the type of fuel, the power output for each unit, the fuel mixture when applicable, and the reserve margins. The generic UC problem can be formulated as:

- Minimize operational cost

Subject to:
- Load forecast
- Minimum up-time and down-time constraints

Generators are scheduled on load over a given time horizon, which can vary from hours to weeks. Operationally, UC typically schedules units on and off load from periods of 5 or 6 hours up to 1 week (168 hours) ahead. Network constraints are usually ignored but can be accounted for via limitations imposed by the operator. They can also cater for interconnector schedules and secondary / tertiary reserve requirements. Commercially available UC programs typically utilize optimization techniques such as Lagrangian relaxation (LR) and integer and mixed integer linear programming (MILP).

Security constrained unit commitment (SCUC) includes pre- and post-contingency thermal transmission constraints [6, 7]. As well as being committed economically, generation is also scheduled in such a manner that the system should survive all possible thermal contingencies. Existing SCUC applications concentrate on the transmission network. However, in the future, SCUC may also have to consider generators connected to the distribution network and aspects of distribution network operation. Integrating SCUC with today’s EMS in order to correctly study the selected period is already a major challenge.

Stochastic UC, to this point, has taken account of the stochastic nature of certain renewable sources such as wind. Tuohy et al. [8] consider wind as a stochastic input to the UC problem and demonstrate that stochastic optimisation is less costly than deterministic optimisation. In the future, stochastic UC will need to account for all variations in all renewable sources. The ideal commitment tool, for a system with high penetration of renewable generation, will be a stochastic, security-constrained unit commitment (SSCUC), an example of which is described in [9]. When the initial SSCUC has been implemented it must then be extended to address additional constraints such as fault or short circuit levels, stability (voltage and transient) issues1, with a minimum number of units required on load at any time to guarantee adequate synchronizing torque. These latter tools will also have to consider the stochastic nature of the generator outputs. Finally, this computation loop will have to be achieved over, say, periods varying from 5 to 168 hours while observing all temporal constraints. It is evident that operational decisions, in this new environment, will have to evaluate a far wider spectrum of possibilities than are considered at present. A possible outline of a commitment process using SSCUC is provided in Figure 2.

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1Voltage stability studies determine bus voltage profiles on the system before, during, and immediately after a major disturbance, while transient analysis calculates how the system responds to disturbances which cause large changes in rotor speeds and power transfers in periods under 1 second. Short circuit analysis simulates the application of short circuit faults at critical nodes and checks if the relevant equipment such as circuit breakers can operate correctly during the fault. Short circuit levels are also a measure of system strength. Low levels are indicative of poor power quality, i.e. voltage dips occur when devices are put on load.
3) State estimator and contingency analysis

As can be seen from Figure 3 [10], the state estimator is central to all security applications. If the role of the control centre is extended, in order to better manage new generation and load patterns, by including facilities such as security constrained optimal power flow (SCOPF), the criticality of the state estimator will significantly increase to a point where the power system may not be controllable in its absence.

Today’s state estimator solution relies heavily on complex numerical techniques but despite this it frequently fails to converge/solve. For the future, state estimators must perform their calculations in seconds since their outputs are required for real-time operations. It should never fail and it should execute at the SCADA scan rate.

Existing state estimator designs may have to be reviewed to account for new stochastic generation and load patterns. The state estimator will operate on data acquired from phasor measurement units (PMUs will not make SE redundant, as measurements and indications can always fail) in substations and may even be implemented at a substation level, reporting results to the EMS at the control centre. Results could include distribution network topologies which may be later used for the dispatch and management of distribution connected generators.

Figure 3: Possible future control centre design

Possibly one of the most difficult concepts to understand, and hence one of the most difficult problems to address, will be that of stochastic contingency analysis. Stochastic CA [11] is defined, for the purposes of this paper, as the $N-1$ analysis of sub-sections of the network with widely varying generation patterns. A simple example would be a generator feeding a load via 2 parallel, restricted feeders. If the generator’s output is less than 50% then one feeder can accommodate the production. However, if it is greater than 50% then the remaining feeder is overloaded post-fault, raising the question for the operator as to how the overload will be resolved? Such issues need to be alerted to the operator both in the commitment and real-time timescales.

One possible approach is outlined in [12] where Monte Carlo sampling techniques are employed, since it is widely recognized that it is impossible to model all possible contingencies. This reference is noteworthy since the sampling technique suggested is used for a contingency or security constrained optimal power flow, which is discussed in the following section. It should also be noted that stochastic CA may also have to recognize dynamic feeder ratings.

4) Security constrained optimal power flow (SCOPF)

Due to the stochastic nature of future generation and load patterns, maintaining the power system in a secure configuration at all times will be challenging. One of the main tools available today which may allow us to address this problem is security constrained optimal power flow (SCOPF) [13], which usually addresses the N-1 thermal overload problem.
Traditionally, the security constrained optimal power flow (SCOPF) determines a feasible point of operation that minimises an objective function, guaranteeing that even if any of a defined set of contingencies occurs the post-contingency state will also be feasible, i.e. without limit violations. At this point it should be noted that while a power flow calculates the power system state for a given set of conditions, SCOPF prescribes how to control the power system to achieve an objective.

The objective function to be minimised depends on the application of the tool. When used in control centres as a security control tool, the common objective functions are minimum losses, minimum deviation from the programmed operation point and minimum deviation of the scheduled area interchange. Other objective functions include minimum reactive allocation, minimum load shed and minimum generation cost. This latter application is known as security constrained economic dispatch (SCED).

A new generation of SCOPF is required, since it will not be possible, in the network planning phase, to consider all possible power system scenarios which may realistically occur. Ideally SCOPF will cycle frequently, which would be every 2 to 3 minutes for a power system, determine which commands need to be issued to the power system so that it is operating securely while considering all relevant constraints, and then, ultimately, issue those commands to the relevant items on the power system. The contingency selection mechanism will be as outlined in the previous section, i.e. stochastic.

One of the key considerations in designing a SCOPF, such as the one being discussed, is the operational security standard. Ristanovic, in [14], outlines the control possibilities as follows:

- Preventive – the traditional approach
- Corrective [15] – rescheduling and fast acting controls
- Mixture of preventive/corrective measures

It is stated that there are obvious differences between both approaches. The preventive formulation offers a higher level of security, but the SCOPF problem is more constrained than the preventive/corrective concept. As a result, the system operating cost is much higher and is more prone to infeasibility than if the latter concept is applied. The preventive/corrective formulation, although less constrained, requires a significantly larger optimization problem to be solved and the system, in order for this approach to be feasible, must have adequate fast acting controls available.

The new SCOPF must be capable of dealing with the following types of constraints, in addition to the existing set of active power, including reserve, and reactive power constraints:

- Fault level
- Voltage stability
- Transient stability
- Inertial and synchronizing torque constraints [16]

A fault level constrained OPF (FLCOPF) and a transient stability constrained OPF (TSCOPF) may be a necessary part of the SCOPF due to the unusual and unpredictable operating configurations which may be adopted by networks to cater for future levels of renewable generation. FLCOPF is discussed in [17]. Typically, the only operational tools available to deal with high short circuit levels are altering the network topology, dividing busbars, switching feeders [18] and de-committing generators. For SCOPF technology to be applied here it will need to consider actions such as switching of feeders, which has not been a standard part of SCOPF armory heretofore. Low short circuit levels may also be a problem when fault levels are too low to activate the relevant protection relay. Since it may not be possible for the control room to deal with low levels of fault current, these issues must be addressed in the planning/construction timeframe. TSCOPFs are discussed in [19–22]. Again the outcome of this facility will be to re-schedule generators and re-configure the network. The same capability questions arise as were highlighted for FLCOPF.

As already mentioned, where SCOPF’s output or set points must consider network topology, i.e. recommendations for feeder and coupler (busbar) circuit breaker positions will be required in addition to existing recommendations e.g. MW/MVAR set points and transformer tap positions. Mixed integer programming (MIP) may be employed for this latter aspect of the new SCOPF.

The possibility exists that there will be a two part SCOPF (Figure 3) – one part based on existing methodologies, but extended so that it is capable of dealing with fault level, stability and inertial constraints, and a second topology based section, possibly based on BIP (binary integer programming) or MILP (mixed integer linear programming), which will cater for constraints via topology management, if required. The question of how these two parts of the one tool would operate together is unclear. However, the topology aspect of the problem will have to be addressed for networks and markets with high renewable generation penetration. For example, restricting a generator to reduce a feeder overload, which may be the recommendation of the traditional SCOPF, may result in the loss of ‘free’ wind energy which has to be produced at a cost elsewhere. However, a change of topology may avoid any restrictions and leave the power system in an equally secure state. The topology of any future network may also include ‘internal’ HVDC links which will have to be operated and controlled as part of a combined AC /DC network and thus be accounted for in SCOPF.

Research has been undertaken which used a topology focused SCOPF to solve voltage and thermal overload problems [23]. However, the application of a SCOPF to resolve fault level or transient stability issues via topology management does not as yet appear to have been investigated.

5) Generation Control

In order to ensure frequency stability, dispatch a large number of generators on the power system, ensure correct interconnector (both AC and DC) and tie line flows and respect transmission constraints, generation control, possibly AGC, will be required in the control centre [24]. It may not be possible, using manual control, to correctly manage all variables associated with renewable generators at high penetration levels. The control scheme, when issuing set points to generators, at transmission and possibly distribution levels, and interconnectors, could depend on SCOPF to supply it with base points [25]. Ireland, for
example, has implemented an initial control scheme, based on the operator’s knowledge, which can issue a global or specific command to wind generators to curtail their output by a specified amount. This scheme is also capable of issuing reactive set points to wind generators connected to the transmission network.

B. Control Centre Design and ICT Issues

The additional/extended applications outlined previously, namely forecasting, SSCUC, SCOPF, state estimator, contingency analysis and generation control will obviously have an impact on the control system architecture, which must evolve from a mainly monitoring role to providing solutions in real-time to the operators, and ultimately executing those solutions directly on the power system. The complexity and capabilities of the control system will increase both in the control centre and in the field, where substation control systems, based on standards such as IEC 61850, will have to bear part of the computational burden.

Telemetry and communications will play a critical role when employing renewable sources in a highly distributed manner. As previously stated, the number of generators will grow but load or demand control will also increase leading to very significant growth in:

- station data quantities, due to the use of PMUs and SCS (substation control systems)
- telemetry sampling rates
- communication speeds
- data accuracy

Additionally, data exchange between TSOs and DSOs, wind control centres, weather forecasting agencies, migration to the internet protocol (IP) and the use of wide area monitoring and control systems will also place a significant burden on the communications network.

The architecture of the control system will have to be carefully designed. Will there be one control centre in charge of all generators, of which there will be hundreds, or will there be multiple centres with a National Control Centre dispatching via distribution control centres and wind farm control centres? [26] Delays, both operational and communications, across boundaries such as the transmission / distribution boundary must be minimised or eliminated since the system will be much more dynamic and require far more timely interventions from the control centre than heretofore.

There will be a step change in the quantity of data and systems to be monitored and managed in the control centre. This, together with the increased number of commands which will have to be issued, point to the need for ‘intelligent’ interfaces in the control room. Situation awareness, for example, will have to be delivered through visualisation rather than through data displays. The control room will become an integral part of the power system, and it could be very challenging to operate the power system without it.

VI. REFERENCES


VII. BIOGRAPHY

Michael Power (SM’00) Michael Power has B.E. (Electrical) and M.Eng.Sc. degrees from UCD. He has over 30 years experience of power system operation with ESB and EirGrid. He joined the ERC in 2009 as a Charles Parsons Award Researcher. He is a Distinguished Member of CIGRÉ, the International Council on Large Electric Systems, and was awarded a CIGRÉ Technical Committee Award in 2004 for contributions to System Control and Operation. He is a senior member of the IEEE.