# Evaluation of Power System Flexibility

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***Abstract*—As the penetration of variable renewable generation increases in power systems worldwide, planning for the effects of variability will become more important. Traditional capacity adequacy planning techniques have been supplemented with integration studies, which have been carried out in power systems with high targets for renewable generation. These have highlighted the increased variability that a system may experience in the future. As system generation planning techniques evolve with the challenge of integrating variable generation, the flexibility of a system to manage periods of high variability needs to be assessed. The insufficient ramping resource expectation (IRRE) metric is proposed to measure power system flexibility for use in long-term planning, and is derived from traditional generation adequacy metrics. Compared to existing generation adequacy metrics, flexibility assessment is more data intensive. A flexibility metric can identify the time intervals over which a system is most likely to face a shortage of flexible resources, and can measure the relative impact of changing operational policies and the addition of flexible resources. The flexibility of a test system with increasing penetrations of variable generation is assessed. The results highlight the time horizons of increased and decreased risk associated with the integration of VG.**

***Index Terms*—power system modeling, power system planning, wind power generation, solar power generation, hydro power generation**

## I. Introduction

Generation portfolios are changing significantly in many power systems worldwide. Concern for the environment and energy security, as well as rising fuel prices, have led to significant, sustained growth of wind and solar electricity generation capacity worldwide. Variable generation (VG), such as wind, solar, hydro and tidal, can be defined as those resources whose output is dependent on the prevailing environmental conditions. The difficulty posed by the integration of these variable resources into existing power systems varies according to the production and scale of the variable resource, its correlation with system load, and the flexibility of the power system in question [1]. Flexibility is defined here as the ability of a system to deploy its resources to respond to changes in net load, where net load is defined as the remaining system load not served by variable generation. Hence, an isolated power system containing mostly generation units with long start up times and low ramp rates will find it more difficult to successfully integrate variable generation than a well interconnected power system, containing many generation units which can start up and ramp quickly. An emerging challenge in power system planning is to evaluate the ability of an existing system to successfully integrate a targeted penetration of VG, and thus to plan future portfolios [2]. This paper will highlight the need to evaluate flexibility in generation planning, examine current planning practices and propose an adaptation of existing reliability techniques to measure flexibility.

High penetrations of wind power generation have been recorded in systems around the world, most notably in Denmark, Ireland, Portugal and Spain [3]. During February 2008, a large net load ramp event in the ERCOT power system highlighted the potential threat that ramp events pose to power system frequency stability [4]. To date, few if any methods exist to determine the degree to which a system is flexible in a long-term planning context [5]. Organizations such as the North American Electric Reliability Cooperation [1], [6] and the International Energy Agency [**?**] have undertaken studies to develop long-term planning aids in order to understand the effect of operational policies at high penetrations of VG. At the same time as increasing penetrations of variable generation are redefining the requirement for flexibility, the deployment of demand side resources offers a new source of flexibility. Foreseeing a potential deficit in fast responding resources, generator manufacturers are striving to develop more flexible generation units, with higher ramp rates and lower minimum generation levels [7]. Therefore, understanding system flexibility will become increasingly important in a planning context.

System load forecasting has removed much of the uncertainty around ramping requirements related to system load [8], resulting in the planning assumption that system operators can predict peak load hours and prepare their generation resources accordingly. In systems where the ramping requirements can be forecast well in advance (i.e. with sufficient time to bring plant online), system flexibility may not be as critical to a system planner. For example, where the daily morning rise dominates the requirement for flexibility over all time horizons, current planning practices are likely to suffice.

Since the construction of a new generation facility has a multi-year lead time, traditional long-term planning is required to ensure the future reliability of power systems. This task is normally carried out for long time horizons (e.g. 20 years ahead) on a rolling annual basis, by either regulators, system operators or utilities, depending on the system [9]. Generation adequacy studies have addressed the question of how much capacity is required to reliably meet system load, at a certain point in time, but have not considered whether the system's planned resources could be operated in a sufficiently flexible manner.

Identifying how much generation capacity and what char-

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acteristics that capacity should possess are key tasks for regulatory bodies, who look to ensure that market designs deliver in the long run, or for vertically integrated utilities, ensuring the suitability of a planned plant portfolio before more detailed engineering and operational analyses are carried out. Investors and plant manufacturers also have an interest in the cycling requirements experienced by potential investments.

Section II presents an overview of traditional generation adequacy techniques and the recent development of integration studies for VG. Section III proposes an extension of current planning to incorporate flexibility into the long-term planning process. Section IV illustrates the method on a test system and Section V discusses some of the challenges presented by the assessment of flexibility, while Section VI concludes.

## II. Generation Planning

Generation planning studies have developed as the targeted penetration of variable generation in power systems has increased. Traditional reliability metrics have been supplemented by variable generation integration studies. The inclusion of operational practices is a developing trend in long-term generation planning, leading to an additional stage in the planning process [6], [10]–[12].

### A. Capacity adequacy planning

Generation adequacy metrics, such as loss of load expectation (LOLE) [13], [14], the expected energy not served (EENS) or well-being analysis [15] are standard measures by which a planned portfolio is evaluated and have served industry well to date. These methods make some general assumptions: the primary assumption being that load shedding will only occur during times of insufficient capacity, either of generation or of transmission. Secondly, in order to consider the capacity adequacy including VG, a probabilistic model is available for the output of these generators which may, or may not, be combined with a Monte Carlo simulation [14].

The methods may include a reserve criterion by which operational constraints are included. Deterministic criteria such as fixed capacity reserve levels are based on heuristics and are simple to implement, and subsequently many power systems employ deterministic criteria exclusively in long-term planning studies [16]. The capacity margin can be set in planning studies using deterministic metrics such as the loss of largest unit (LLU), or probabilistic methods such as an LOLE target. Well-being analysis considers both probabilistic and deterministic criteria in assessing the adequacy of a planned system's resources, and results in a set of indices which describe the system's adequacy as one of three outcomes: healthy, marginal or at risk [15].

System load and VG forecast errors and the outage of generation resources are the main causes of unpredicted ramping events. With the development of high penetrations of VG, significant uncertainty surrounds the future ramping requirements of a system. Additionally, peak net load forecasting is dependent on variable generation forecasts, potentially challenging the assumption that a system operator will have sufficient forewarning to prepare generation resources. Finally, challenges have arisen in establishing the contribution to the generation capacity adequacy of a system by the integration of VG [17]. Hence, new long-term planning methods which incorporate variable generation and variable generation forecasts have been developed, leading to the development of VG integration studies.

### B. Integration studies

Integration studies have been carried out for many power systems pursuing a high penetration of variable generation [11], [12], [18]–[20]. These studies have tended to focus on understanding how VG will impact on the daily operation of a power system and the transmission reinforcement required by employing production cost models [21]. Unit commitment and economic dispatch models use synchronized forecast and actual system demand and variable generation, and typically simulate year long, or multi-year periods of the operation of a power system. Similar to traditional generation or transmission capacity adequacy calculations, these studies require a system load forecast for the study year and individual capacities for the generation portfolio. However, these methods also require greater detail on the generation units, including heat rates, and forecast VG output at the same resolution as the system load data.

Integration studies have also required enhanced simulation and modeling tools. The adaptation of unit commitment to a stochastic [22] and rolling framework, and the inclusion of VG forecasts [23] can provide an insight into how systems might operate under high VG penetrations. Operating reserve is typically planned for on a day ahead basis, to ensure that the planned quantities match the generation resources available [24]. In many systems the amount of fast acting operating reserve required has been determined by the loss of the largest unit (LLU) or a similar deterministic criterion, where no VG exists. Current practice favors probabilistic methods [25] over traditional deterministic methods [26], which try to calculate the 'right' amount of operating reserve for a power system. Similarly, a system of evaluating flexibility in the operational time frame has been developed based on the adequacy of reserves [27]. No long term planning metric exists, however, to evaluate the overall system flexibility.

The use of integration studies has required an identification of the reserve requirements for VG. Söder [28], Dany *et al.* [29], and more recently, Doherty *et al.* [30] and Morales *et al.* [31] have developed probabilistic methodologies to determine the optimal amount of operational reserve required when wind generation is included in the energy mix. These methods determine a system's ability to meet uncertainty in the net load forecast error in a short term operations planning context. Söder [28], for example, uses a concept of time horizons, tailored to reserve category definitions in the NORDEL system, to calculate, ex-ante, the requirements for reserve in each category as a function of the derived standard deviation of unpredicted changes in wind and system load. The result is a determination of the amount of reserve required to meet a certain percentage of the unpredicted changes in net load. However, the ability of a system to meet the

total requirements of both predicted and unpredicted net load changes remain unaddressed. Integration studies have adopted such methodologies within the production cost simulation to ensure that some additional reserve is provided for the additional variability caused by increased VG. The inclusion of a reserve target will alter the production time series of certain generation resources.

In contrast to the above, the flexibility metric proposed in this paper measures the ability of a system to use its resources to meet both predicted and unpredicted net load changes. The flexibility of a system is dependent on how the system is operated: if a system provides a large amount of reserve at all times, that system is better able to meet changes in net load. Two identical systems, operated to meet the same net load, but employing different reserve quantification methodologies, will result in different values for the system flexibility under the proposed metric.

Integration studies require extensive data and computation to produce indicative results of future power system operation and are dependent on a proposed generation portfolio and transmission network, which is in turn dependent on a capacity adequacy study. Therefore, portfolio development is an iterative process in order to produce the least cost optimal generation portfolio. The inclusion of a system flexibility assessment stage, before proceeding with integration studies, may expedite the planning process by identifying the characteristics of resources which are required by a system, Figure 1.

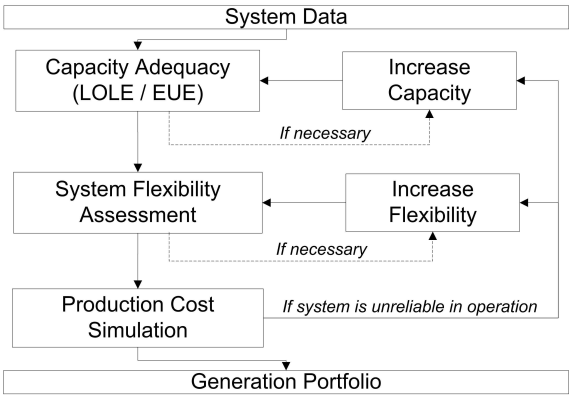


Fig. 1. Generation planning scenario development

### C. Long-Term Planning for Flexibility

Key tasks for long-term planning currently include system load forecasting, VG forecasting, establishing planned closures and construction of resources, capacity expansion studies and adequacy calculations. Planning for the secure operation of a system has traditionally been left to generation investors and system operators, since the assumption is made that once sufficient capacity exists the system can be operated reliably. A developing trend in planning for VG is the consideration of flexibility in the generation planning process [1].

Leite da Silva *et al.* [5] approach the flexibility problem from a long-term planning of operating reserves context, employing sequential Monte Carlo simulation of system load, wind output, and hydro generation, combined with unit commitment and economic dispatch, to evaluate a range of reliability metrics for a system. Various capacity expansion options can be evaluated using this method. However, it is restricted to generation outages, and system load and VG forecast errors, rather than identifying how well a system can cope with the overall variability of the net load.

A new planning metric is required to measure the flexibility of a system, in the same way as the LOLE measures the capacity adequacy of a power system, with deference to operational constraints. An overall understanding of how well a system can manage predicted and unpredicted changes in the net load over a wide variety of time horizons will ensure that the results from long-term generation planning are robust when VG is integrated into a power system. Current planning methodologies, such as in [32], produce portfolios with sufficient flexibility implicitly in a context of low penetrations of variable generation. However, an explicit understanding of, and planning for, the challenges posed by the flexibility required by high penetrations of VG is missing from long term planning methodologies. A useful system flexibility metric should try to achieve the following:

1) Quantify the ability of a system to respond to short-term changes in system load, VG, and generation unit outages in a long-term planning context.
2) Minimize data requirements and computational effort, while appropriately considering the operational constraints of a system.
3) Remain independent of reserve definitions to ensure applicability across power systems.

The metric should complement capacity adequacy calculations and system operation simulation at the planning stage. The inclusion of such a metric would ensure that planned systems meet the dual objectives of possessing both sufficient capacity to meet system load, and sufficient ability to meet short-term net load changes. Here we propose a metric by which system flexibility can be assessed, which can be integrated with existing planning techniques, as proposed in Figure 1. This metric includes the ability to assess the flexibility of a system over an extended time period, and to consider the contribution made by all elements of the power system to meeting predicted and unpredicted net load changes.

## III. Methodology

When measuring the generation capacity adequacy of a power system, the system load is the requirement which a system's generation must meet. However, system load and VG may both set the requirement for flexibility and may contribute to the provision of flexibility concurrently. Therefore, a first step towards developing a flexibility metric is to identify those elements which require flexibility (e.g. system load, VG and generation outages) and the resources available to provide flexibility to a system [6]. The time series of changes in net load is taken as a system's requirement for flexibility, since it represents the combined requirement for flexibility from both system load and VG. While generation outages affect the flexibility of a system, the amount of flexibility available is reduced during periods of generation outages.

Conventional generation is the main existing provider of flexibility to a system but may be supplemented by curtailment of VG, interconnection to other power systems, energy storage or demand side resources (DSR), depending on the specific circumstances of the system. The flexibility of a power system is dependent on the operational policies of a system operator and, consequently, is dependent on the state of each generation resource.

Unlike generation adequacy planning, the time horizon considered plays an important part in the evaluation of flexibility. Any change in system load is rarely monotonic for long periods. Therefore, it is important to understand the system's flexibility over a range of time horizons, as data permits. The time horizon is defined as the duration of the net load change, i.e. 15 minute, 1 hour or 12 hour changes, as distinct from an observation, which is a single value in a given time series.

The direction of the changes in net load is an additional consideration for flexibility. The magnitude and frequency of occurrence of net load changes, and resources available to meet upward and downward changes are asymmetric. For example, resources at maximum output can only assist when net load is decreasing, while offline resources may be able to come online during periods of increasing net load.

### A. Flexibility Metric

In order to remain consistent with current long-term planning metrics, it is desirable to expand or adapt existing planning concepts to consider flexibility. The most appropriate existing metric is the loss of load expectation, which results in a temporal expectation of a system's inability to meet system load. By adapting the LOLE methodology, a similar expectation can be calculated for a system's inability to provide the required flexibility. Calculation of the LOLE can be broken down into two separate processes [14]. First, a resource model is built, called the capacity outage probability table (COPT), which employs unit characteristics (e.g. unit size and forced outage probabilities) to develop a probabilistic distribution of the unavailable generation capacity. From this distribution, the loss of load expectation can be calculated by summing the probabilities that there will be insufficient capacity to meet each observation in the system load time series.

The insufficient ramping resource expectation (IRRE) is the expected number of observations when a power system cannot cope with the changes in net load, predicted or unpredicted. Calculation of the IRRE follows a similar structure to the LOLE, however, rather than forming a distribution of the unavailable generation capacity, a distribution of the available flexible resources is formed for each direction and time horizon. Secondly, as with the LOLE calculation, the probability that the system has insufficient ramp resources at each observation, over each time horizon and direction, are calculated from the available flexibility distribution ($AFD$), from which the overall metric is computed. Calculation of the IRRE for all selected time horizons provides an understanding of the ability of a system's resources to meet the variability requirements of its net load. The IRRE can be calculated in a sequence of steps as illustrated in Figure 2.

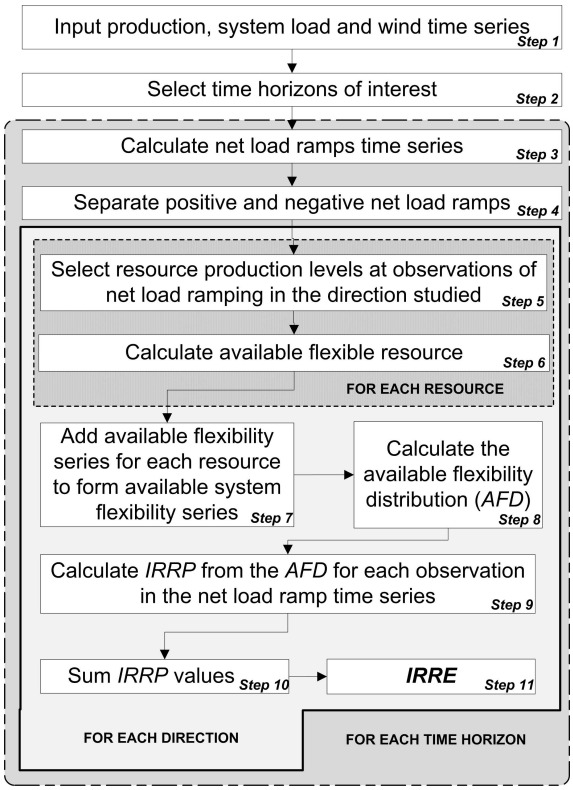


Fig. 2. IRRE calculation algorithm

This metric fulfils the role of a System Flexibility Assessment method outlined in Figure 1. Separate analyses are required to determine the acceptable value of the IRRE for a system and the appropriate actions to be taken, should the system possess insufficient flexibility. The following three sections describe the data preparation, the development of the resource model and the calculation of the IRRE.

### B. Data Preparation

In order to calculate a system's flexibility, operational characteristics are required for each generator, which is in contrast to the LOLE which only requires knowledge of a resource's rated output and forced outage rate. Each flexible resource's energy production time series, which may be a historical or simulated time series, and the time series of the availability of each resource are required. The production time series for each resource is required since the flexibility available in either direction is limited by the maximum rated output and current production for upward flexibility, and between current production and the offline state for downward flexibility, assuming sufficiently long time horizons to reach these limits. By employing a production time series, the operator's adversity to risk from forecast errors is included in the resources' availability to ramp. Each resource's maximum and minimum rated output, start up time, ramp up and down rate, forced outage probability and production levels are required.

The time horizons studied may be chosen based on criteria such as the magnitude of ramping events or the frequency of occurrence of monotonic ramps in each time horizon. Chosen time horizons may also coincide with the start up times of

a common generation technology (e.g. combined cycle gas turbine) in a system, or an important operational time frame, such as a forecast horizon. The net load ramping time series is then calculated for each time horizon, and separated into two time series of increasing and decreasing net load ramps (steps 2 - 4, Figure 2). The net load ramp time series $NLR_{i,+/-}$, for time interval $i$, at observation $t$, can be calculated as follows:

$$NLR_{t,i} = NL_t - NL_{t-i} \quad (1)$$

$$1 \leq t \leq |NL| - i \quad (2)$$

$$NLR_{t,i,+} = NLR_{t,i} \quad \forall NLR_{t,i} > 0 \quad (3)$$

$$NLR_{t,i,-} = NLR_{t,i} \quad \forall NLR_{t,i} < 0$$

where $|NL|$ is the number of observations in the net load time series. Only net load observations in the direction of the IRRE being calculated are required in each case.

The resource model employed in the evaluation of the IRRE in either direction is calculated using the production time series at times of net load ramping in either direction, as shown in step 5 of Figure 2. Therefore, the resources' dispatches are separated depending on the direction of net load ramping at each instance in time, which ensures that any correlation between the available flexibility in a system and net load ramps is accounted for.

### C. Resource Models

Formulation of a resource model for system flexibility begins with a model for each resource. For an LOLE calculation, and depending on the level of detail required, a generator can be modeled as being in one of $N$ states, with the simplest model including two states: the outage and fully available states. Capacity adequacy techniques assume that the availability of a resource is an independent random variable.

Since the flexibility of a system is determined by both the physical attributes of a system's resources and the operation of those resources, the resources cannot be deemed to be independent and the temporal correlation between the flexibility of resources must be preserved. Therefore, a multi-state model of a resource's flexibility is unsuitable here, since such an approach assumes independence between the availability of resources. However, the addition of each resource's time series of available flexibility to form a system flexibility time series results in a resource model which appropriately accounts for the interdependence between resources.

The flexibility available from each resource can be obtained at each instance by examining historical or simulated production time series. Since the flexibility of a unit is heavily dependent on the operational state of each resource, long-term planning would now directly consider the bounds on the availability of flexibility arising from operational constraints. An operator's decision to provide regulation and contingency reserve for predicted changes in net load and the possibility of net load forecast errors, respectively, is reflected in the dispatches of each unit. Therefore, the ability to meet the flexibility required by unpredictability and variability in the net load is considered in a single stage. As a consequence, production time series are required to directly model the theoretical maximum amount of flexibility each resource may provide, prior to the application of technical constraints (e.g. ramp rate constraints).

*1) Resource Flexibility:* Starting with a resource's active power production time series observations during increasing, or separately decreasing, net load, the availability of that resource to provide flexibility in either direction can be calculated (step 6, Figure 2). Determining the flexibility of a resource is best explained by a notional 100 MW natural gas unit scheduled at 15 minute resolution, whose output over a 24 hour period is shown in Figure 3. The unit has an upward and downward maximum ramp rate of 4 MW/min. and a minimum generation level of 40 MW. Figure 3 shows the unit's production, with the shaded areas representing the upward and downward 15 minute flexibility available from the unit at each observation in time.

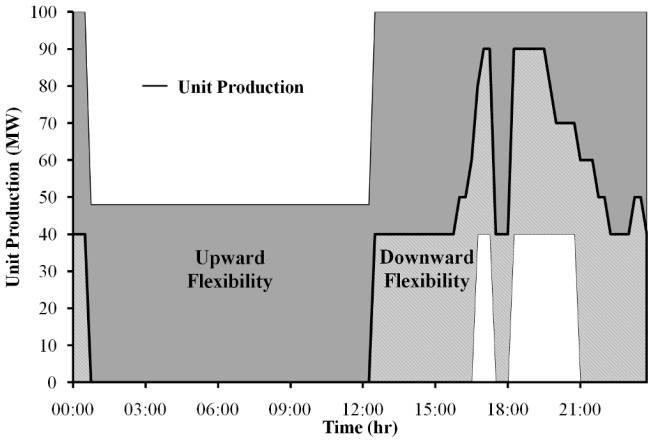


Fig. 3. Flexibility available from example unit in 15 minutes during a one day period

Calculation of the available upward $(+)$ flexibility ($Flex_{t,u,i,+}$), for a resource $u$, over horizon $i$, at observation $t$ in the net load ramp time series, at maximum production ($Prod_{MAX,t,u}$), or while on outage, is trivial, since the resource cannot offer any upward flexibility. When a resource is offline it cannot provide any flexibility, unless the start up time, $S_u$, for that resource is less than the considered time horizon, and it has sufficient time to reach minimum stable production. If the unit can meet this start up criterion, the upward flexibility is the upward ramp rate, $RR_{u,+}$, multiplied by the remaining time once the start up time is subtracted from the time horizon. This is shown in Figure 3, where the unit has a 3 minute startup time and so can reach an output of 48 MW in 15 minutes from an offline state. Upward flexibility is bounded by the maximum production capacity of the resource. For part load production, the upward ramp rate, the maximum and minimum stable production levels, $Gen_{MAX/MIN,u}$, may be binding constraints on the available flexibility. Equations 4 to 6 summarize the upward flexibility available from each unit at each observation in the production time series when the unit is available. $Online_{t,u}$ is the binary online variable for each resource.

$$Flex_{t,u,i,+} = RR_{u,+} * (i - (1 - Online_{t,u}) * S_u) \quad (4)$$

$$s.t.\ \ Prod_{t,u} + Flex_{t,u,i,+} \leq Gen_{MAX,u} \quad (5)$$
$$Prod_{t,u} + Flex_{t,u,i,+} \in \Re \backslash (0, Gen_{MIN,u}) \quad (6)$$

As with upward flexibility, calculation of the downward flexibility on outage is trivial, since the resource cannot decrease its output. At maximum or part load production, the available flexibility is constrained by the downward ramp rate and by the minimum stable production level. Figure 3 demonstrates that the minimum generation constraint on downward flexibility is active between 18:00 and 21:00. Upward and downward flexibility should be calculated for each unit and for all chosen time horizons. Equations 7 to 9 summarize the downward flexibility available from each unit at each observation in the time series.

$$Flex_{t,u,i,-} = RR_{u,-} * i * Online_{t,u} \quad (7)$$

$$s.t.\ \ 0 \leq Prod_{t,u} - Flex_{t,u,i,-} \quad (8)$$
$$Prod_{t,u} - Flex_{t,u,i,-} \in \Re \backslash (0, Gen_{MIN,u}) \quad (9)$$

The above logic can be extended to include resources which can consume as well as produce power, or which have ramp rates as a function of resource output. Once the flexibility available from each resource is calculated, a system wide resource model can be created.

*2) System Flexibility:* Addition of the individual resource time series results in a system flexibility time series ($Flex_{t,SYSTEM,i,+/-}$) which maintains the temporal dependency between generators, arising from unit commitment and economic dispatch decisions.

$$Flex_{t,SYSTEM,i,+/-} = \sum_{\forall u} Flex_{t,u,i,+/-} \quad (10)$$

The available flexibility distribution ($AFD_{i,+/-}(X)$) is the empirical discrete cumulative distribution function of the flexibility available, $X$, which is calculated from the system flexibility time series, from Equation 10, using the Kaplan-Meier estimator of cumulative density functions (step 8, Figure 2) [33]. This fulfils the same role as the capacity outage probability table, used in the calculation of LOLE. Figure 4 outlines the $AFD_{15min.,+}(X)$ and $AFD_{15min.,-}(X)$ for a system comprised of two units, identical in type and schedule to the example unit in Figure 3, for a one year time series. The $AFD_{i,+/-}(X)$ indicates the probability that $X$ MW, or less, of flexible resource will be available during the $i$ time horizon.

Since the resources in Figure 4 remain offline for a significant proportion of the time, but can start quickly, there is a low probability that there will be less than 96 MW upwards flexibility available in 15 minutes at any time, but a high probability that there will be insufficient downward flexibility. Having obtained the respective $AFD_{i,+/-}(X)$ they can then be compared to the net load ramps for each direction and time horizon before calculating the IRRE.

### D. IRRE calculation

The probability of insufficient flexibility being available to a system operator at each point in time is the cumulative probability that the system will not be able to provide the amount of ramping required by the net load change at that point in time. The $AFD_{i,+/-}(X)$ function, calculated in step 8 of Figure 2, provides the means by which the probability of insufficient ramping resources can be calculated at each observation in the time series. In order to exclude those cases when just enough flexibility is available in the $AFD_{i,+/-}(X)$, the net load ramps must be reduced to a value just below the net load ramp value. In this case the magnitude of each net load ramp is reduced by 1 MW. Therefore, the insufficient ramping resource probability ($IRRP$) at each observation, $t$, for each time horizon, $i$, is:

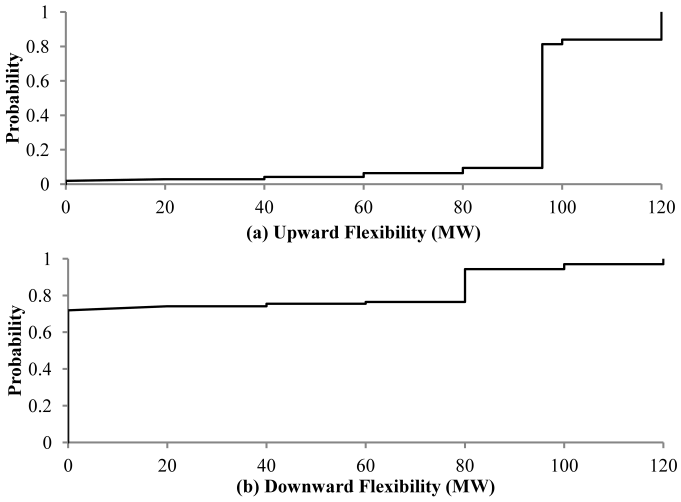


Fig. 4. $AFD_{15min.}(X)$ in (a) upward and (b) downward directions

$$IRRP_{t,i,+/-} = AFD_{i,+/-}(NLR_{t,i,+/-} - 1) \quad (11)$$

where $NLR_{t,i,+/-}$ is the net load ramp at observation $t$ in either direction (step 9, Figure 2). The sum of the $IRRP$ values over the entire time series, $T_{+/-}$, for each direction, results in the insufficient ramping resource expectation, as shown in Equation 12:

$$IRRE_{i,+/-} = \sum_{\forall t \in T_{+/-}} IRRP_{t,i,+/-} \quad (12)$$

Assuming notional 15 minute upward ramps during a 4 hour period of 45 MW/15 min., 60 MW/15 min., 115 MW/15 min. and 5 MW/15 min. the $IRRE_{15min.,+}$ can be calculated for the two resource example using the upward $AFD_{15min.,+}$ in Figure 4(a), as:

$$\begin{aligned} IRRE_{15\ Min.,+} &= AFD_{15,+}(45-1) + AFD_{15,+}(60-1) \\ &\quad + AFD_{15,+}(115-1) + AFD_{15,+}(5-1) \\ &= 0.0429 + 0.0429 + 0.8395 + 0.0294 \\ &= 0.9547 \text{ 15 minute periods/4 hr} \end{aligned}$$

Therefore, this hypothetical system consisting of two peaking gas resources cannot meet the upward changes in the net load with an $IRRE_{15\ Min.,+}$, of 0.9752 observations in these four hours. This would represent a very high probability that the system will face a shortage of upward flexibility. Additionally, should the net load ramps have occurred consecutively, the system load would have increased by 220 MW, exceeding the 200 MW installed capacity. This highlights the importance

of calculating the system flexibility over a number of time horizons, such as 1 and 4 hours in this case. The same exercise can be carried out for the downward ramping direction and the results added to give the $IRRE_{15min.}$, since the upward and downward values are independent of each other.

## IV. Test System

The flexibility of a six unit test system is assessed here using the IRRE method. The unit characteristics and costs are summarized in Table I. This system is designed so that there is sufficient generation capacity, but it is deliberately lacking flexibility. The test system has an LOLE of 3.04 hours per year and a capacity margin of 34.6%. When 50 MW of wind, with a 31% capacity factor, is included the LOLE decreases to 1.82 hours per year. The 50 MW of wind generation represents an energy penetration of 5.75%. With the addition of a further 50 MW of wind generation, 11.5% of the energy required by the system is met by wind generation.

TABLE I
Test system unit data

| Unit | 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|---|
| Max. Capacity (MW) | 150 | 150 | 100 | 75 | 75 | 50 |
| Min. Capacity (MW) | 60 | 50 | 50 | 40 | 30 | 10 |
| Ramp Rate$_+$ (MW/min.) | 2 | 2 | 4 | 4 | 6 | 10 |
| Ramp Rate$_-$ (MW/min.) | 2 | 2 | 4 | 4 | 6 | 10 |
| Start-up Time (hr) | 18 | 18 | 6 | 6 | 4 | 0.017 |
| Forced Outage Rate | 0.03 | 0.03 | 0.02 | 0.02 | 0.02 | 0.015 |
| Start Up Cost ('000 €) | 20 | 20 | 15 | 15 | 10 | 5 |
| No Load Cost (€) | 500 | 500 | 400 | 400 | 300 | 100 |
| Marginal Cost (€) | 20 | 20 | 30 | 30 | 40 | 50 |

System load and wind power time series are based on the 2009 Republic of Ireland system load and wind generation data at 15 minute time resolution. The system load data was scaled to give a peak demand of 392 MW. Mixed integer unit commitment and dispatch was solved using Plexos and the Xpress-MP solver, to obtain 15 minute resolution production time series for each unit. Wind and load were assumed to be perfectly forecasted, but this is not a necessary condition when measuring the IRRE.

So that the effect of 50 MW of variable generation, resource properties and operational practices on a system's flexibility can be demonstrated clearly three scenarios are considered. The flexibility of the system is evaluated when: (A) no outages occur, (B) outages may occur but no reserve is provided, and (C) when 60 MW of reserve is included in the unit commitment. In order to demonstrate the effect of increasing VG penetration, a scenario including 100 MW of wind capacity is also examined.

### A. Results: Upward flexibility

System flexibility is calculated for all time horizons from 15 minutes to 24 hours in 15 minute steps, Figure 5. The IRRE is given as a percentage of the number of upward ramps for that time horizon, during the study period. In general, the system has sufficient upward flexibility for time horizons greater than 6 hours as units 3 - 6 may provide flexibility from an offline position. As expected, the 60 MW of reserve provided for in scenario (C) tends to increase the number of online resources, and therefore, the flexibility available in this scenario. This results in the lowest $IRRE_+$ across all time horizons. Intuitively, the outage of resources with no reserve provision, in scenario (B), will result in the highest $IRRE_+$ values, given that the system will have fewer means by which it can provide flexibility when resources become unavailable.

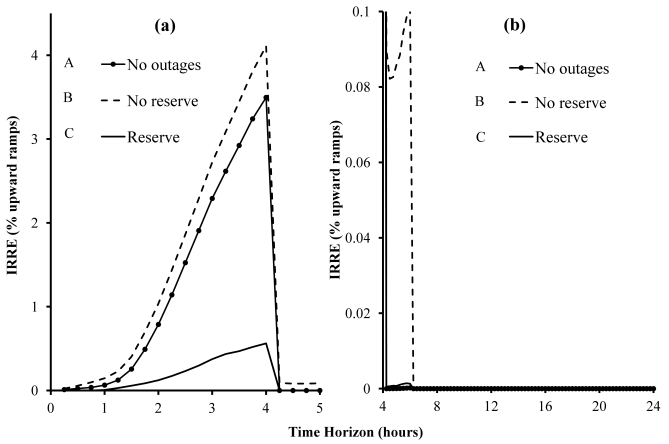


Fig. 5. Upward IRRE test system results with 50 MW of wind. The scale on the vertical axis changes between the (a) 0 and 5 and (b) 4 and 24 hour timescales

Figure 5 shows distinct peaks occurring at the 4 and 6 hour time horizons, since the system operator may only call upon one resource (unit 6) to provide flexibility from an offline state for time horizons less than 4 hours, and only two units for time horizons less than 6 hours (units 5 & 6). These peaks could pose a serious threat to the operation of the system, and planners could draw the conclusion that additional resources should be targeted at providing flexibility to reduce these peak $IRRE_+$ values. Between 6 and 24 hours, the $IRRE_+$ decreases from a peak of 0.1% for the 6 hour time horizon to 0% for all time horizons between 6.25 and 24 hours, when 60 MW of reserve is provided, scenario (C).

The contrast between scenario (A), when no outages occur, and scenario (B), when outages occur, provides insight into what might happen if imperfect forecasts of net load are used. Introducing unexpected changes in net load will increase IRRE values further, since the risk of having insufficient flexibility is increased. However, the consumption of flexibility by generation outages contributes to the high $IRRE_+$ values in scenario (B), which is alleviated by the possible commitment of units 3 or 4 in time horizons greater than 6 hours.

### B. Results: Additional wind generation

A further 50 MW of wind is added to the system to give a total of 100 MW of wind generation installed. The commonly anticipated outcome is that an increase in net load variability will result in higher $IRRE_{+/-}$ results, while the generation resources displaced by VG may provide additional flexibility. The standard deviation of net load in the original case is 42.01 MW, compared to a new standard deviation of 45.81 MW, while the average net load decreases from 256.40 MW in the original case to 240.76 MW when 100 MW wind capacity

is installed. Since the extra wind generation is displacing an additional 5.75% of energy, the decrease in average net load contributes to a lower LOLE of 1.29 hours per year, and may increase the flexibility available from individual units, given their lower average production. However, the flexibility may decrease over shorter time horizons if mid merit units, which historically operated on the margin, are forced offline and cannot provide flexibility from an offline state.

Figure 6 shows the $IRRE_{+}$ values for the 50 MW and 100 MW wind generation cases. It can be seen that for time horizons less than 3.75 hours, the $IRRE_{+}$ is slightly lower for the 100 MW wind generation case, given an increased availability of online flexibility. If the wind generation has a capacity factor of 31%, the additional 50 MW of wind will reduce the net load by 15 MW on average which will result in reduced output from generators, and consequently increased flexibility. Between 3.75 and 6 hours higher $IRRE_{+}$ values are observed for the 100 MW scenario, as the effect of greater variability, with increased wind capacity offsets the increased availability of flexibility. This result highlights the balance between the effects of increasing variability due to wind generation and the corresponding increased system flexibility. Beyond 6 hours, the system possesses sufficient flexibility to manage all ramping for either wind generation case, since the flexibility requirement of the demand dominates that of wind generation.

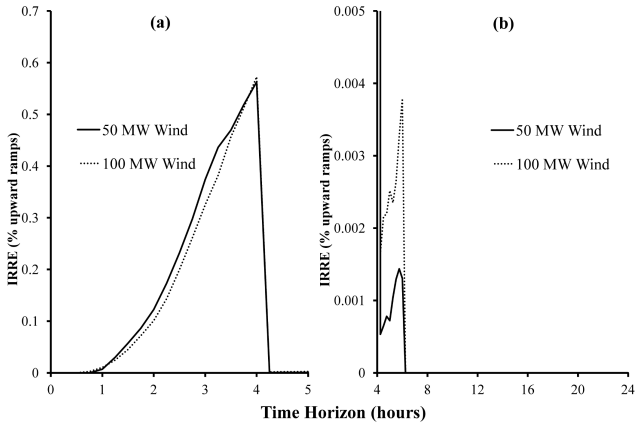


Fig. 6. Upward IRRE test system results for 50 MW and 100 MW of wind generation. The scale on the vertical axis changes between the (a) 0 and 5 and (b) 4 and 24 hour timescales

### C. Results: Downward flexibility

The downward flexibility is calculated for the system with both 50 MW and 100 MW of wind generation capacity and 60 MW of reserve. It is worth noting that the maximum time required for the least flexible resources (units 1 and 2) to ramp from maximum output to an offline state is 1 hour 15 minutes; therefore, all resources in the test system can provide maximum flexibility beyond this period. Consequently, the only remaining driver of $IRRE_{-}$ values is the downward net load ramping time series.

The system is sufficiently flexible to meet the ramping requirements of the system with 50 MW of wind generation (scenario (C)) over all time horizons, as shown in Figure 7. For the 100 MW wind generation case, the peaks in the $IRRE_{-}$ occur during the 11.75 hour and the 19.75 hour time horizons, representing the flexibility required by the additional 50 MW of wind generation. The unit commitment and dispatch will require less units online, and results in the cheapest units (units 1 & 2) remaining online. These units have relatively high minimum generation levels, resulting in the potential for inadequate availability of downward flexibility. The $IRRE_{-}$ is zero for time periods between 15 minutes and 5 hours since the magnitude of net load changes are small and there is always sufficient down flexibility to meet the largest downward changes in these horizons.

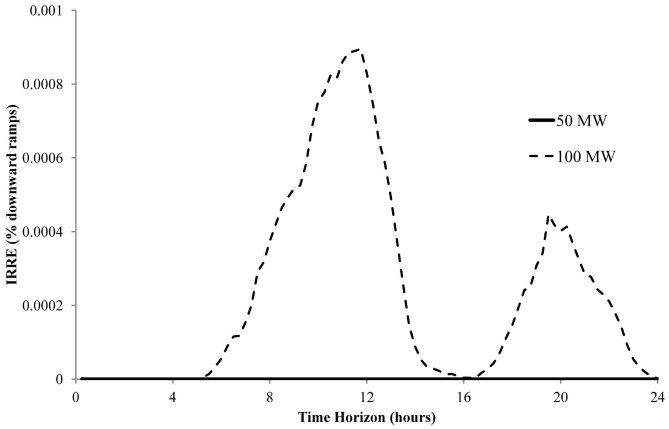


Fig. 7. Downward IRRE test system results with 50 MW and 100 MW of wind generation capacity

The 11.75 hour horizon represents the difference between the daily peak load in early morning and the midnight valley. Similarly, the 19.75 hour horizon represents the difference between the peak load on a Friday evening and the lower weekend load. The peak $IRRE_{-}$ of 0.0009% occurs at the 11.75 hour time horizon (Figure 7), indicating that the system is unlikely to face a significant threat from decreasing net load. In comparison, the $IRRE_{+}$ for the system at the 4 hour time horizon reaches 0.05% of upward ramps per year for scenario (C) (Figure 5), significantly greater than the maximum $IRRE_{-}$, and represents the most challenging time interval for system flexibility.

## V. Discussion

Expansion of an existing generation portfolio currently results from a system level optimization, drawing on the system load forecast, capital, fuel and operational costs and the existing generation capacity [32]. This optimization has, heretofore, guided investment decisions in delivering plant portfolios which contain the necessary capacity to meet system load and the flexibility to respond to changes in system load or outages of generating units. While such an optimization may take into account transmission constraints, the system loads chosen are non-sequential and only include selected periods when system load is challenging to meet for capacity adequacy reasons. The provision of flexibility may be implicit to many planning processes currently in use, however, the additional flexibility required by an increase of variable generation may require explicit treatment. The new planning process proposed

in this paper is an addition to the production cost and reliability modules included in [32], to explicitly consider a system's flexibility requirements.

While this paper presents the IRRE algorithm in its most essential form, a number of system or technology specific modeling issues may arise. The proposed metric is based on a probabilistic model of the available flexible resources, which assumes independence between the net load changes time series and the available flexibility time series. In a system whose resources are dominated by conventional generation, the temporal correlation between changes in net load and the net load itself tends to be both negative and small (e.g. average correlation coefficient of $-0.11$ for the Republic of Ireland system in 2009). Given the dominance of the system load profile in dictating the requirement for flexibility, it follows that at high net load, downward changes are more likely, leading to a negative correlation. While a weak dependency exists between the available flexibility and net load changes, the IRRE conservatively under estimates a system's flexibility, since at the highest net load levels, most generators would be at high output and available to offer the additional downward flexibility likely to be required by the system.

In practice, the number of periods per year when there is insufficient flexibility is very low and limited insight is gained by the analysis of the number of such events. The available flexibility distribution tends to overestimate the inflexibility of a system. The $AFD$ is created using data from the entire study period, separating the link between the change in the net load at an observation and the flexibility available at that observation. By calculating the probability of insufficient flexibility with the annual distribution of available flexibility, some cases where the magnitude of the net load ramp is close to the amount of flexibility available may result in a high probability of insufficient flexibility. Therefore, the value of this metric is to highlight those time horizons of most risk, rather than determine the absolute level of risk.

Furthermore, the IRRE methodology is an attempt to measure the flexibility of the overall power system, and not exclusively the flexibility of the generation resource. Since the flexibility is a function of how the system is operated, the resultant IRRE is a function of the preparedness of the system to meet net load variability, predicted and unpredicted. Consequently, the ability of a system to forecast changes in net load fundamentally affects the realized flexibility of a system. The IRRE method makes no explicit distinction between predicted and unpredicted net load changes, since the system makes provision for unpredicted changes in the net load by assessing and providing for the amount of reserve required. Unless the electricity market or system operator's policy is to ignore the possibility of a net load forecast error in the unit commitment, the effect of the system's provision for forecast errors is captured.

Additionally, it is assumed that a system operator could employ all resources available in pro-actively managing a ramping event from the outset of the time horizon. This may not materialize in reality if there is insufficient knowledge of the duration of the ramp event. Therefore, while it is assumed that all resources already online and those with a start up time shorter than the time horizon are available, in reality a forecast error may reduce the time available to commit offline resources. Therefore, in systems where significant net load forecast uncertainty is present, it may be advisable to carry out a sensitivity analysis by measuring the flexibility of the system when net load changes are met by resources available in time horizons less than the study time horizon, e.g. the IRRE of a system when resources available in 3 hours or less are used to meet 4 hour net load changes.

Further research is required to assess the validity of IRRE values calculated with limited availability of data. Similar to the calculation of indices such as the capacity value of wind, many years of data may be required so that IRRE values converge to a stable result. Results in [17] and [34] suggest that high resolution and multi-year data is required to correctly model the inter-annual changes in wind energy output. This effect and the effect of generation outages may carry through to the calculation of the IRRE, although further work is required on this matter. However, calculation of the IRRE for short time horizons depends greatly on the availability of high resolution data. This may greatly increase the computational burden, and result in simplification of the production cost modeling, affecting the accuracy of IRRE values for those time horizons.

The IRRE has the potential to assist in a variety of planning decisions. If a system operator is seeking to increase a system's flexibility, new metrics can be developed further to decouple the effect of a single system resource on the IRRE, which could then be employed to evaluate the relative merit of different proposals. For example, wind curtailment could also be considered as a solution for a system operator faced with decreasing net load. A complementary metric could be developed to measure the expected amount of curtailed wind energy, given target IRRE values for a power system.

Future development of the IRRE may lead to a valuable assessment tool to aid planners and market participants in choosing the most beneficial type of resource addition to a system. Depending on the system's targeted penetration of VG, the variability characteristics of that VG type and the underlying system, a less costly change in operational policy may provide more flexibility to the system compared to the addition of a flexible generation unit. The importance of including operational issues, when little experience with VG exists, at the long-term planning stage gives increased confidence in system robustness as VG is further integrated. The IRRE metric can be used as the system flexibility assessment in a new type of long-term generation planning, proposed in Figure 1.

## VI. Conclusion

The challenge currently being faced by many power systems is to plan for secure and reliable operation with the integration of a high penetration of VG. In response to a need to quantify a system's ability to meet changes in system load and variable generation, the IRRE metric provides a means of measuring a system's flexibility over different time horizons and directions. The IRRE potentially offers those involved in planning with a means to measure a system's flexibility, to highlight the time horizons of net load ramping in which the system is most vulnerable, and a tool to improve portfolio development.

The IRRE was demonstrated on a test system, with the addition of variable generation, to highlight the time horizons of concern to the successful operation of the system, and the impact of increasing VG on system flexibility. It is shown that the addition of VG may decrease the IRRE of a system over certain time horizons, while requiring increased flexibility in others. Peak $IRRE_+$ values for the test system are seen to coincide with the start up times of blocks of flexible resources, in comparison to the $IRRE_-$, which is seen to be driven by the magnitude of net load changes.

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