Bonneville Power Administration, EPRI and Northwest Power and Conservation Council

Flexibility Assessment Methods DRAFT

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2.1. Introduction

With increasing penetration of variable renewable generation such as wind and solar PV, there has been an increase in the importance of system flexibility, which is the ability to manage deviations in load, net of variable generation. With increased system ramping caused by wind and solar, flexibility is needed to ensure systems can manage the increased variability and uncertainty.

System flexibility, like many other aspects of the bulk electric system, can be examined as a supply and demand problem. A holistic assessment of flexibility will examine the resources available to supply flexibility and the factors driving the demand or requirements for flexibility. These can either be assessed separately or at the same time within a simulated power system dispatch model.

Assessing the demand or requirements for flexibility generally involves using historical or synthesized data to estimate how much additional variability and uncertainty will be expected on a future power system. This is normally expressed as increased operating reserve requirements, though flexibility requirements may also be included in unit commitment and/or dispatch. **There are two essential approaches to assessing the need for flexibility in the literature. The first is to use historical data and/or simulated data along with a risk preference. The second involves altering the unit commitment logic to have constraints requiring flexibility in the dispatch of the system and to use metrics that track constraint violations.**

There have been a variety of approaches to assessing the supply of flexibility ranging from examining the characteristics of the physical resources on the system without considering how they may be operated, through to detailed simulation of the system operation. System simulation requires significant modeling effort, and also requires detailed information to estimate how the system may be operated. This includes issues such as how transmission to neighboring regions is managed, how commitment and dispatch is performed, how energy forecasting is used and how markets will be operated. If these issues are not well known in advance, then simulations of this type are extremely difficult to carry out with any degree of certainty. **Estimating the adequacy of flexibility in these simulations involves tracking instances in the simulation where predefined conditions are violated and estimating the likelihood of those violations, usually with a Monte Carlo approach.**

Approaches to assessing flexibility that only examine physical characteristics will likely overestimate the availability of resources to provide flexibility. Thus the results from such studies can only be seen as a “screening” type analysis. **The “screening” analyses include taking specific system conditions such as peak and minimum load and estimating flexibility from these starting points or selecting a particular system state in which flexibility is expected to be constrained.**

There are four methods that fall between a full system simulation and “screening”. **They involve: 1) assessing the maximum system ramping capability using an approach such as Cumulative Ramp**

Duration Curves (CRDC), 2) examining a system committed strictly for economic dispatch and measuring the periods where the system is short of flexibility, 3) adding states estimates, e.g. online or forced out, to generating units that supply flexibility to the system, and 4) adding generation characteristics such as must-run and committing or de-committing all units and estimating the ramping characteristics. Note some combination of these could also be used and there may be additional methods possible which fall in between these four main categories.

2.2. Flexibility Requirements

There is a large range of literature assessing flexibility requirements. These generally take the form of assessing the incremental reserve requirements to manage wind and/or solar PV. The most significant methods are reviewed here at a high level. More detailed reviews of these requirements for operating reserve imposed by variable generation are given in other papers, e.g. [NREL11a].

2.2.1. Operating Reserve Requirements

In the academic literature, there are a number of notable papers on reserve requirements. With increased penetrations of variable generation, the variability and uncertainty on different time scales need to be adequately covered. A relatively basic method to do this is to assess historical data and determine the standard deviation of the time series. Expressing this as a confidence interval that covers a certain number of standard deviations allows for reserves to be carried according to risk preference (e.g. 99.7% of variation in a Gaussian distribution for three standard deviations). Doherty and O'Malley propose a method which calculates reserve requirements by combining the requirements due to wind and load forecast error and holding a constant probability of a load shedding event for each hour as reliability criteria [Doherty05].

Da Silva et al examine the amounts of static and operating (spin and non-spin) reserves required to maintain reliability with increased penetrations of variable generation [daSilva10]. Here, long-term planning metrics are augmented with a new set of metrics relating to operating reserves. Monte-Carlo simulation is used to determine these performance indices with variable generation represented by sampling from historical wind power data based on wind speed and power conversion characteristics. This probabilistic approach ensures sufficient reserves of the right type are carried, and planning margins are sufficient.

Bouffard explores adapting the classical unit commitment problem to account for operational flexibility requirements [Bouffard11]. This is included in an additional inequality added to classical UC problem, where it is compared to the flexible capacity available. The former is calculated based on current commitment and expected dispatch (accounting for offline resources which can come online). This method allows for different flexible response times to be examined, and could potentially be used with more simplistic data outside the UC problem.

As well as the above academic papers, there are a number of studies which talk about the increased reserve requirements. These generally analyze historical data, or data synthesized to determine what wind and/or solar output may look like for a given location in the future based on weather patterns from a past year or years. The most relevant of these are efforts from the National Renewable Energy Laboratory (NREL), which have evolved over the past few years. A good summary from 2010 is provided in [NREL11b]; the methods have been updated since but use much the same concepts. As part of both the Eastern and Western Wind and Solar Integration Studies, NREL and its contractors have prepared series of reserve requirements which will be required to manage the variability of demand and net load in the regulation and intra hour time frame. These reserve requirements are the basis for the system flexibility requirement. The regulation and flexibility reserves are based on the standard deviation of demand, wind and solar variability over time scales of 10 and 60 minutes respectively. The variability of wind and load is measured as the absolute change in load or wind generation over a given time period of interest. For solar generation, the variability is measured with respect to the clear sky output of the solar generators at any given time [Ibanez 2013]. The reserve requirements are set to meet a user determined range of variability. Using the reserve requirement in each net load interval, the amount of reserve at any net load level can then be deduced. The most recent example showing the latest iteration of this NREL method was for phase 2 of the Western Wind and Solar Integration Study [NREL 2013].

Other methods have also been proposed in the various wind and solar integration studies. Another notable example was proposed in [PNNL2012]. The joint effort between Pacific Northwest National Laboratory (PNNL), the California Independent System Operator (CAISO) and Areva lead to the development of a ramping requirement indicator for use with the Energy Management System in California. The proposed method is a determination of regulation, load following and ramping requirements based on historical and forecast data. Using the "swinging door" methodology, time series are broken down into specific ramps with individual ramping, capacity and regulation measurements. The joint probability of meeting these three measurements is then used to estimate reserve requirements.

The North American Electric Reliability Corporation (NERC) Integration of Variable Generation Task Force established a number of task forces to address some concerns arising from the initial analysis completed by the NERC group. Task force 1.4 was established to examine the requirements for flexibility and flexibility metrics [NERC10]. Based on experiences from areas with high penetrations of variable renewables, the group concluded that the main characteristics to include when measuring flexibility include ramp magnitudes, response rates, ramp frequency and ramp intensity. The group proposed a method to characterize the flexibility of a system based on these four characteristics. This was one of the first documents to address the issue of power system flexibility explicitly. The flexibility assessment methods proposed were not demonstrated, but a framework to structure a possible assessment was outlined. The main outcome was a measurement of flexibility requirements as defined by the ramp intensity metric. The ramp intensity was defined as the product of the magnitude and ramp rate of a given ramp. The ramps were categorized based on the time scale and frequency of occurrence.

2.3. Assessing available flexibility and flexibility adequacy

There are a number of methods to assess available flexibility on the system. As described above, these fit on a spectrum from analyzing purely the physical characteristics of all resources on the system, to estimating how much flexibility is available based on detailed simulation of future years, or examining historical data. Here, this is split into three main areas – a screening level, an intermediate level and a detailed simulation level. Note that in some of these methods, there is also an assessment of the variability required. In putting a method into practice, there may be an opportunity to use the flexibility availability assessment described here with a different method described in the previous section to determine flexibility requirements.

2.3.1. Screening Available Flexibility

Screening the available flexibility in a system means assessing the resources based purely on their physical characteristics, without assessing how they may operate. The purpose here is to determine what the capability to ramp is for a set of resources. The International Energy Agency, in the Flexibility Assessment Tool (FAST) version 1 provides a good example of this [IEA11]. This is a Microsoft Excel based spreadsheet examining flexibility resources available. The dispatch at peak and minimum load is estimated based on generator characteristics and user knowledge. The available flexibility from resources is then quantified on different time horizons of interest (15 minutes, 1 hour, 4 hours and 12 hours) for up and down ramping. This is then extrapolated to determine the maximum variability which could be met by the resources on the system. Assumptions are made for flexibility from interconnection to neighboring regions, demand response and storage which are optimistic in nature. The variability of load, wind and PV is assumed uncorrelated and worst case variability which can occur is therefore assessed. This may mean being overly conservative in the real amount of variability which can be met, while the assumptions leading to a final "penetration level possible" may be too optimistic in disregarding the reality of the likely dispatches which could be seen. Some components of the tool could be used to provide qualitative assessment on the resources available and the positive and negative factors affecting a particular system's flexibility, but the overall results are likely to be very high level and may not be very accurate given the range of assumptions.

Another screening type approach is used in Portland General Electric’s (PGE’s) 2012 Integrated Resource Plan. Adopted from Northwest Power and Conservation Council (NWPCC) paper discussed in the next subsection, this takes what appears to be a simpler approach than that paper. For each of the relevant time scales up to one hour, it quantifies the required flexibility and then the available flexible resource. The available resource is quantified by 'turning on' all resources and moving them up to maximum capacity as soon as possible (for down ramp, only hydro resources are examined). The study compares the amount of available capacity estimated in this way with the variability required and determines whether there is sufficient flexibility. The amount required is examined for different percentiles. Forced outages and regulation requirements are not accounted for. Different quarters are examined as Q2 is not expected to have as much flexibility available. The study shows PGE meeting up ramp requirements in 2015 but not 2020 and not meeting down requirements in either 2015 or 2020, though these can be managed through curtailment and are economical in nature.

A final screening type approach is found in a paper from Ma and Kirschen [Ma, 2013]. The flexibility of conventional generation resources is dependent on their ramp rate, operating range and start up time. In this paper the authors present a flexibility index for a system's generation resources both individually and aggregated on a system-wide basis. The method does not consider the requirements for flexibility due to ramping or contingency events, rather it is a means to measure the flexibility of the resources. A further limitation of this methodology is that it does not consider the limitations on the availability of flexibility of hydro and other energy limited resources.

2.3.2. Intermediate Assessment

Intermediate assessment methods are defined here as methods which take a more detailed approach than those in the previous subsection, but still do not examine a full commitment and dispatch study, with all of the associated modeling implications and challenges. The first example is from Schilmoeller [NWPCC12]. This paper quantifies the requirement for and provision of imbalance reserves. The supply of imbalance resources is quantified using an approach that allows for ordering of the resources available over different time scales such that varying speeds of response can be combined to give overall system ramping available. This shows the total ramping that can be provided over a certain amount of time. The method then computes imbalance reserve requirements, describing first a cumulative ramp duration curve, which doesn't account for recovery of capacity. The ability of capacity to recover over the course of a net deployment is then described considering the initial conditions, referred to as a path. The total requirements are then computed as the minimum resource required meeting all of the paths. Comparing the requirements to the capacity available shows whether and how the system does not have sufficient flexibility. This was simplified for the approach used by PGE described above.

The International Energy Agency improved upon the FAST tool in a subsequent study to that described above [IEA13]. Using basic assumptions about a dispatch stack of the resources in a given area, the FAST v2 method determines the limits on the availability of flexibility based on optimistic (flexible) and pessimistic (inflexible) assumptions about how a power system is operated. The system is dispatched using the two different perspectives on dispatch over the course of a time series (e.g. 1 year). The optimistic dispatch commits excessive capacity to meet net demand, resulting in generation being operated close to minimum generation levels in order to maximize upward maneuverability to meet upward ramps. The pessimistic dispatch operates the system in a way which does not take into account the ramping, start-up and minimum up or down times of units, but based on plant economic characteristics only. The result of the pessimistic approach is a dispatch which is inherently short on upwards flexibility. In order to assess downward flexibility, the roles of each dispatch perspectives are reversed. Based on the dispatches, the availability of flexibility from the system's resources can be determined, and the number of periods when a system is potentially short of flexibility can be calculated for a variety of time horizons. This is an intermediate level approach which, while requiring extensive data, is not computationally intensive. These types of methods are useful in assessing flexibility at the outset of long-term planning studies to understand the approximate limits and requirements for system operation.

An alternative, but similar, method which is comparable to the IEA FAST v2 methodology is to determine the flexibility of the system using a dispatch stack methodology to determine the state of a system's generation resources over the course of a year, as described in Lannoye *et al* [Lannoye12a]. Using these states (offline, online, dispatch level), the flexibility from generation units can be determined over a course of a year over a variety of time horizons (e.g. 5 minutes, 1 hour, 3 hours). This approach allows significant numbers of scenarios to be assessed quickly while capturing some, but not all, of the likely operational limits of a system. The amount of available flexibility is then compared to the net load ramping requirements at each coincident interval in time as well as the requirement for contingency reserve. Using that comparison, a variety of metrics can be calculated to measure the frequency and magnitude of potential flexibility deficiencies.

A final intermediate approach is given by the Electric Power Research Institute (EPRI), [EPRI13]. The methods in this report describe levels 1 and 2 of the EPRI flexibility assessment tool, Inflexion[1]. This assesses variability of the system net load based on time series data (one year at 5 minute intervals preferred). A number of analyses are performed over a range of time scales, allowing various metrics to be quantified and graphs produced for flexibility requirements. The flexibility requirements can be adjusted in many ways to reflect many of the requirements methods. In level 2, the flexibility available is quantified using characteristics such as ramp rate, start time and minimum generation, together with whether a generator is must run or not. The available flexibility is quantified in terms of system ramp rate assuming all units are either online or all are offline, which gives upper and lower bounds in terms of how much flexibility is available from a standing start versus how much is available if all are online. The minimum generation level is determined based on providing information about which generators are likely to be kept online if possible. This is then used to estimate potential curtailment due to lack of down ramping capability. The up ramping capability is compared in a similar fashion to the PGE method. To obtain accurate results on flexibility available, significant details about likely commitment status are needed. These levels do not calculate a dispatch and this can only be used to estimate flexibility provision, but metrics and graphs produced do allow for comparison of how different resources provide flexibility. Time of day and month of year are also examined to determine when flexibility requirements are highest.

2.3.3. Detailed Assessment Methods

The final set of approaches requires more detail on system operations, generally meaning a full unit commitment and economic dispatch is required. New metrics and techniques have evolved to use existing or adopted production simulation tools to assess flexibility. The insufficient ramping resource expectation (IRRE) metric is a probabilistic method of assessing the frequency of flexibility deficits [Lannoye12b]. This metric is dependent on the outcome of production cost modeling which determines the dispatch level of each resource over the course of a study period. Based on the dispatch level, resource parameters and availability, a distribution of flexibility available in the system can be determined. This can be then used to determine the probability of meeting net load ramping events throughout the course of the year. When those probabilities are aggregated into an expected value, the result is a metric for the overall flexibility of the system. This metric can be applied to ramping in the

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[1] EPRI's Inflexion tool is currently only available to funders of the EPRI project "Strategic and Flexible Planning". However, BPA is a member and the relevant parts of that tool could be made available if of interest to this group.

upward and downwards directions and for a range of time horizons, so that distinct flexibility issues can be identified.

EPRI extended the IRRE approach [EPR13], and four metrics are calculated using results from either a production simulation model or historical dispatches. Using generator characteristics as in the EPRI Screening methods, and the time series of flexibility requirements, these metrics assess flexibility adequacy. Insufficient Ramp Resource Expectation is as described in Lannoye (2012) above. Probability of Flexibility Deficit and Expected Unserved Ramping are, respectively, measures of the likelihood and total magnitude over one year of flexibility deficiencies. These are calculated by comparing a time series of available flexibility with requirements based on the load, wind and PV for each particular hour (i.e. if a given hour has low load and high wind, the more extreme ramps are likely to be increases in net load and vice versa). Percentiles can also be used to calculate the requirements, which are assessed over different times scales and for up and down ramping. The fourth metric is a well-being analysis based on the combination of magnitude and frequency; users determine comfort levels (e.g. allow for x MWh and y% likelihood but warn at higher levels), and the results are graphically displayed. These metrics have been tested using case studies but, other than IRRE, not on a real system.

The REFLEX tool developed and implemented by E3 consulting, can be characterized as a detailed Monte-Carlo simulation of a system under a wide range of system operating conditions [E313]. Using a similar concept to the SERVM tool to draw Monte-Carlo scenarios of demand and variable generation, the availability and generation levels of flexible resources are determined using conventional scheduling tools, such as Energy Exemplar's Plexos tool. A significant number of short, three day scenarios are simulated and the resulting energy and reserve violations are aggregated and assessed. The impacts of these violations are characterized by a set of proposed metrics which measure the frequency and magnitude of flexibility shortages for both upward and downward flexibility. It is also possible to deduce from these results, the cause of the flexibility violation (e.g. ramp rate limits, operating range limits, minimum up time limits etc.). In order to calculate these detailed metrics, a considerable amount of data is required for the production cost simulation and to create the distributions of demand and variable generation. Additionally, since the generation dispatches are determined using standard production cost tools, the computational burden can be significant. However, the nature of the simulation means that the outcome of different scenarios can be computed in parallel, reducing the overall run time. This method has been implemented on the Californian system to examine the flexibility of the system under future high variable generation scenarios.

Menemenlis et al. [Mene11] propose a method of assessing flexibility based on definitions from the domain of process control and design. The paper is focused on determining the effect which operational processes have on the deliverability of the flexibility available from generators as opposed to identifying the technical capability of a system's resources. The underlying flexibility metric is based on simulating a wide variety of probability weighted scenarios, and then determining the balancing reserve required to meet these scenarios based on certain defined variables such as ramp rate of the system and demand. Based on user defined reliability or economics limits for each of those variables, the size of the balancing reserves can be reduced to reflect the user risk preferences. The ratio of the volume of reduced requirements to the volume of the original requirement is an indication of the system flexibility. This methodology could be used in both an operational and planning context, but is computationally and data intensive. Therefore, this method is more suited to real-time, or near real-time operations, rather than planning applications.

A final detailed method to assess flexibility is proposed in [Studarus13]. This metric is designed specifically for hydro systems. Taking into account the range of constraints on a hydro system, it shows how much flexibility is operationally available as a time series. The focus is on short term hydro scheduling, and compares a deterministic representation of the flexibility available from the system based on confidence intervals with a deterministic representation of the inherently stochastic flexibility requirements. The main purposes are as a visualization tool for operators and for short term optimization. Comparing existing requirements (INC and DEC) with constraints on available resources, the lack of upwards or downwards flexibility can be quantified. This assumed that operations remain the same in the future, similar to many other methods, and aspects such as shorter dispatch interval do not occur. It can be used to visualize, for example, over the next 4 hours, 24 hours and 7 days, and compare to forecasts of what will be required, to determine whether there is sufficient flexibility. This could feasibly be used with planning data to assess adequacy. The main contribution of this method is to determine flexibility available from hydro generation, while providing a detailed look at whether this implies enough operational flexibility available.

While some of the methodologies proposed are for the exclusive assessment measurement of flexibility, other proposals adapt existing reliability assessment approaches to incorporate system flexibility limits. An example is given by EPRI’s use of the SERVM reliability assessment and production simulation tool [EPRI13]. Using production cost simulation tools, which relax certain constraints in return for reduced computational time, the loss of load probability can be calculated using Monte-Carlo type draws of demand and variable generation production data. By including ramping, and other temporal constraints in production cost simulation tools such as ASTRAPE's SERVM tool, when load shedding occurs, it can be caused by any combination of capacity inadequacy, ramping shortages or forecast uncertainty. As a result, the system LOLE measured over a wide range of scenarios using this method can account implicitly for the flexibility needs of a system.

A flexibility measure that has been proposed in California is designed to procure sufficient flexible capacity to meet ramping requirements [CAISO14]. This calculates a need for flexible capacity for each month based on historical data. This is equal to the largest 3 hour net load ramp combined with the maximum of the largest contingency or 3.5% of the expected peak load. The requirement is further split into a first need based on largest 3-hour ramp for each month, a second need based on the difference between 95% of the largest ramp and the largest secondary ramp (secondary being the second largest ramp in any given day), and a third need based on 5% of the maximum 3 hour net-load ramp in a month. These requirements are then allocated across different load serving entities according to how they are deemed to contribute to the need. Load serving entities can offer plant to meet these obligations based on certain characteristics such as dispatchability and period of time during which they are available. This metric uses a significant amount of data analysis to come up with flexibility requirements which are relatively straight forward, albeit very much based on the CAISO system.

2.3.4. Flexibility in Resource Planning

As well as flexibility assessment as described above, there may also be a need to assess flexibility in resource planning. Ma and Kirschen [Ma13] propose a method to consider flexibility in generation planning by formulating an expansion planning problem as a unit commitment model which includes the possibility to add new plants to the system. The method proposed in this paper models a system for a set of five representative weeks of each year for the study period. By including wind, solar and other variable generation, the model is designed to add specific generation types to the system based on the least cost approach to meeting the demand. This is a computationally intensive means to calculate the optimal generation portfolio, but is one which explicitly considers the need to take flexibility into account when carrying out generation expansion planning.

While explicit flexibility constraints or criteria could be included in generation expansion planning algorithms, current research and development favors the inclusion of flexibility implicitly. Shortt *et al.* [Shortt13] developed a generation expansion algorithm which determines the optimal development of a generation portfolio over a wide range of demand and ramping scenarios; this uses a simplified unit commitment and economic dispatch algorithm with certain constraints relaxed, and simplified representation of generator characteristics, to enable Monte Carlo type analysis of the system studied. This approach considers inter-temporal constraints as part of the scheduling algorithm. In order to avoid energy or reserve violation penalties, the generation expansion algorithm ensures that the system has sufficient flexibility and capacity to meet both criteria. The advantage of the simplified scheduling based approach to generation expansion over classical screening curve methods includes inter-temporal constraints while allowing for a large number of scenarios to be examined.

2.4. Conclusions

The above is an attempt to provide an initial overview of the most relevant work in assessing flexibility. It can be seen that there is a significant variation in the amount of data required, the level of modeling and the subsequent level of accuracy of results. It should be noted that any assessment carried out will have a wide range of assumptions, and therefore it is important that whatever methods are chosen are suitable for the purpose they are being used for. For example, a high level assessment may be useful in determining whether a given mix is likely to have sufficient flexibility, but may not be detailed enough to give exact usage of the resources from a revenue planning perspective. Similarly, assumptions about system operations in a unit commitment based study may mean that the results are only valid for a certain set of assumptions about how the system is operated and may not be as useful if the system were to be operated differently.

2.5. Data Requirements

From the above, it is clear that in these types of assessments, the more data that is available, the more information can be contained in an answer. However, there is also clearly diminishing returns, whereby additional data may not add significant information, but may require a large amount of simulation to be useful. Based on that, the following data has been identified as a first set of essential data for any study. Further data may also be required based on particular methods chosen:

Time synchronized time series for wind, load and other non-dispatchable generation. It is essential to have time series covering a range of time as long as possible, at as high a resolution as available (up to say 1 minute). Additionally, if different regions are to be examined (i.e. different Balancing Authorities, or transmission constrained regions within one BA), then the time series will have to be local to that region. If examining future systems, the load, wind, etc will have to be representative of future conditions. For load, this may mean relevant scaling, but for wind, it may require synthesis of data for location of new wind plants, if no data is already available, to ensure geographic diversity is captured.

Existing reserve requirements, or the method to calculate them, will be required in order to understand how variability and uncertainty of wind and other non-dispatchable resources can impact on requirements.

Physical characteristics of flexible resources: This includes installed capacity, minimum stable level, ramp rate, minimum up and down times and start up times. It will also require forced outage rate, maintenance timing and whether there are any additional constraints on system operations (must run, time of day limits, energy limited, etc). Demand response and energy storage resources can also be examined here, with additional information on energy limits, charge/discharge efficiency and call limits as appropriate.

Most studies can use the operating history of resources as a guide, either to setup the simulations, or determine whether to count a resource as flexible. At a minimum, this would require capacity factor, but aspects such as number of hours online, start/stop behavior, and minimum generation hours are useful.

Other data will also likely be needed based on particular methods chosen, but the above would likely be required for all studies. If not available, they would need to be synthesized based on user experience and/or generic data (e.g. based on NERC GADS).

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3. A Review of IRPs

3.1. IRPs with Significant Detail on Flexibility Assessment

3.1.1. Portland General Electric

In section 5 of their 2013 IRP, PGE looked at flexibility requirements using supply and demand curves for flexible capacity of the PGE system.

The demand curve was built using 1-minute data. The demand for a 1-minute ramp was then defined by looking at the distribution of all 1-minute changes in load net wind. This was then carried forward with all changes in load net wind up to 60 minutes. The statistics taken from this distribution were the maximum, 99th percentile, 95th percentile, 5th percentile, 1st percentile and minimum. The maximum and upper percentiles define a need for upward ramping whereas the minimum and the lower percentiles define a need for downward ramping. The demand curves were separated by quarters because of a supply dynamic in the second quarter with hydro.

The supply curve for upward ramps involves hydro assets as well as traditional and distributed thermal and demand response assets. The assumption is made that assets are in a starting state based on normal economic conditions, e.g. high heat rate thermals that would normally only dispatch to high market prices are assumed to be turned off. The downward ramp supply is assumed to be only hydro assets, though it is noted that wind output can be curtailed it is not included in the analysis because it is an expensive option.

The assessment was to compare the various supply curves developed to the appropriate distribution of demand curves. These comparisons were then qualitatively discussed.

3.1.2. Puget Sound Energy

In appendix G of their 2013 IRP, PSE looked at flexibility requirements by using an hourly dispatch from the AURORAxmp production cost model then simulating the intra-hour flexibility demand using load, wind, hourly scheduled interchange and forced outages.

PSE used a 95% confidence interval to assess the need for balancing reserves hour ahead. That is, the reserves procured leading into the hour needed to be sufficient to cover 95% of the deviations from load and wind. This was represented as three types of reserves. Spinning capacity, which are described as an "INC capacity for which resources already be online and synchronized to the system; INC capacity, which can be met by capacity from off-line, 10-minute-ready resources, or spinning capacity in excess of the minimum spin requirement; and DEC capacity, which is the ability to decrease hourly scheduled generation. For metrics, PSE looked at the number of hours in which the PSE system was unable to support the 95% CI set aside for reserves.

For intra-hour flexibility PSE modeled 10-minute level wind and load deviations along with the need to balance hourly shifts. They then calculated the times when the committed resources were unable to follow the load, i.e. there was either unserved energy or excess energy. For metrics they used the average megawatts of unserved and excess energy, a “proxy CPS2 score” which did not include frequency bias, as well as the percentage of increments with shortfall for spin requirements and average megawatts for that shortfall.

3.2. IRPs without Significant Detail on Flexibility Assessment

3.2.1. Avista

Avista states in their IRP that they plan for operating reserves, regulation, load following, wind integration and a planning margin. The IRP included a forecast of reserve needs. Methods for forecasting were unclear.

Bonneville Power Administration (Resource Program)

BPA in their 2013 Resource Program anticipate a shortage of balancing reserves. The Resource Program references the White Book Federal System Needs Assessment for this result. For the 2012 Needs Assessment, BPA modeled a FCRPS reserve limit of 900 MW incremental and 1,100 MW decremental and used the delta between those and the forecast requirement to calculate the need.

3.2.2. Clark County PUD

Clark County PUD in their 2012 IRP does not have a method for assessing the system capability to meet flexibility requirements.

3.2.3. Eugene Water and Electric Board

EWEB in their 2011 IERP speaks specifically to the ability of demand response to provide flexibility but does not have a method for assessing the system capability to meet flexibility requirements.

3.2.4. Idaho Power

Idaho Power states in their 2013 IRP that changes in intermittent generation will be the primary driver of future reserve requirements. They point to their Wind Integration Study Report for details. They do not propose in their IRP to add significant intermittent generation and thus they conclude that the current supply of flexible capacity is sufficient, presumably because the system is capable of meeting current ramping requirements.

3.2.5. Northwestern Energy

Northwestern in their 2013 IRP primarily depended on the PowerSimm software which is an hourly dispatch production cost model. Reserves were likely forecast and treated as an input into the model.

3.2.6. PacifiCorp

In appendix F of their 2013 IRP PacifiCorp forecasted the need for spinning and non-spinning reserves and forecasted the supply of flexible resources. The supply forecast included all resources capable of providing spinning reserves. Primarily these are hydro and thermal resources. They specifically state the reserve capability of natural gas-fired resources can be close to the difference between the nameplate capacity and the minimum generation. There was no forecast of downward reserves or evaluation of the supply in the IRP. However, downward reserves were covered in the wind integration section of the IRP.

3.2.7. Seattle City Light

Seattle in their 2012 IRP used the AURORAxmp software which is an hourly dispatch production cost model. Reserves were likely forecast and treated as an input into the model.

3.2.8. Snohomish County PUD

Snohomish County PUD in their 2013 IRP assigned a letter grade to potential resources for dispatchability and flexibility. They did not pursue a quantitative method to evaluate supply and demand for flexibility. They state current within hour balancing is performed by BPA, but anticipate that future variable generation resources will need to be paired with flexible resources.

3.2.9. Tacoma Power

Tacoma Power in their 2013 IRP use a consultant Wood Mackenzie that runs the AURORAxmp production cost model. Reserves were likely forecast and treated as an input into the model.

4. Data and Model Description

5. Flexibility Assessment Methods Evaluation

The evaluation of flexibility can be thought of on a spectrum of detail as given in Figure 1.

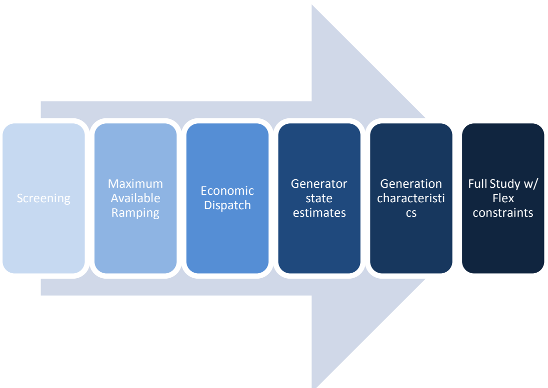

Figure 1: Detail of Flexibility Assessment

5.1. High Level Assessment Methods

5.1.1. IRRL

5.1.2. CRDC

5.2. Detailed Assessment Methods

Here, two parts are examined – first intra hour requirements are described that are used in a hydro model. Then results from that model are used to examine inter-hour flexibility assessment, which can be used to determine how close to flexibility constraints the system is.

5.3. Intra hour Requirements

Here, the main goal was to determine requirements based on analysis of 1 minute data. This was used to determine the ramping required with an hour, based on net load (load minus wind) changes within an hour. The following table and figure shows the ramping requirements by month for different percentiles, in MW. These were then used in hydro simulations that ensured these requirements could be met. The 2.5th and 97.5th percentiles were chosen to cover most of the expected ramping required.

Table 1: Ramping requirements by month based on covering 2.5th and 97.5th percentile

Hourly	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Max INC	1758	1460	1915	1445	2108	1203	1139	1536	2250	1566	1626	1460
99.9th	1330	1221	1387	1193	1159	949	929	977	1021	1274	1268	1211
99th	956	1030	1005	953	855	693	698	701	696	874	905	940
97.5th	825	898	842	800	704	551	570	583	577	730	776	816
95th	682	717	676	644	565	455	480	496	469	599	645	689
5th	-520	-522	-529	-491	-499	-434	-496	-511	-477	-448	-482	-564
2.5th	-598	-616	-626	-588	-612	-550	-593	-611	-578	-548	-575	-679
1st	-683	-730	-740	-702	-763	-704	-713	-759	-726	-714	-714	-827
0.1st	-920	-1118	-1082	-1167	-1223	-1096	-1094	-1103	-1029	-1024	-1082	-1232
Max DEC	-2376	-1687	-1649	-1974	-2438	-1712	-1587	-1713	-2214	-1209	-1823	-1677

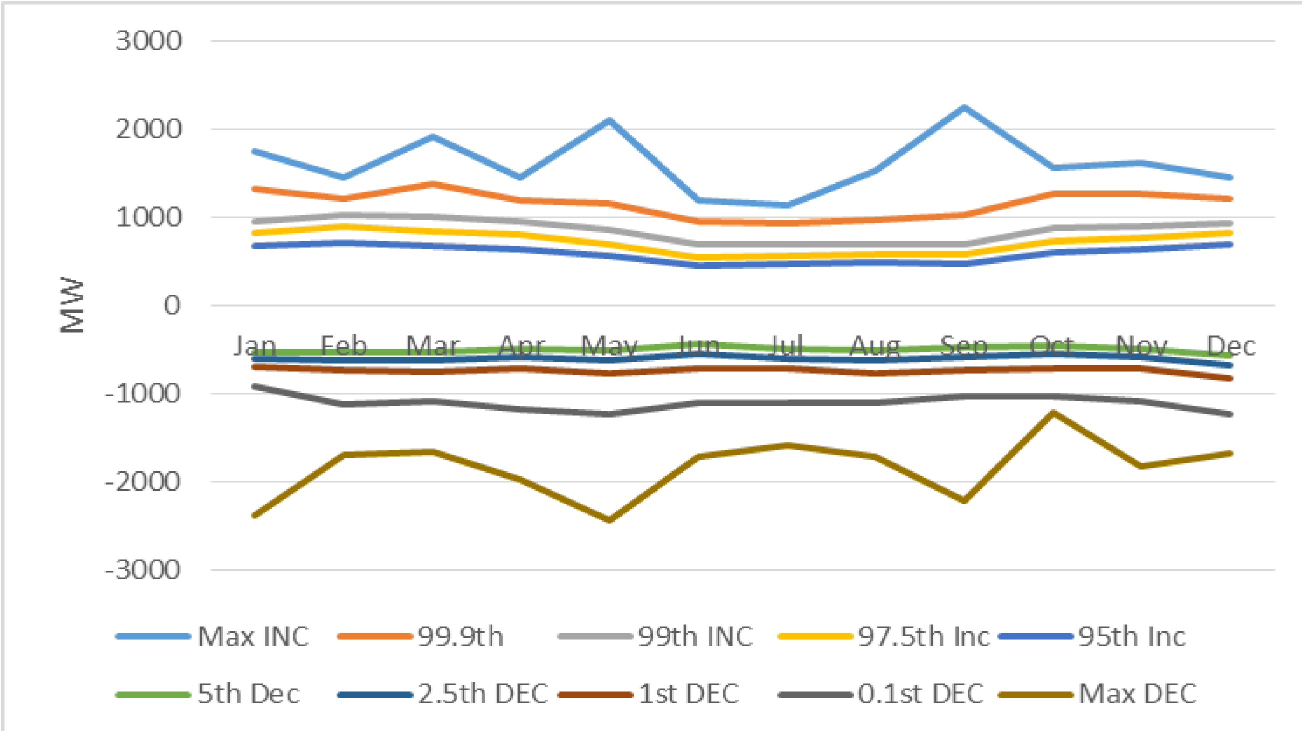

Figure 2: Intra-hour flexibility requirements by month for different percentiles

As can be seen, the requirements are relatively constant throughout the year. It can also be seen that the choice of percentiles such that 95% of ramps are covered does leave very large ramps uncovered. It would be expected these are covered using other methods, e.g. demand side or intertie. Looking at the absolute numbers, a total of approximately 1300MW of total INC and DEC is carried to cover 95% of ramps (adding 97.5th and 2.5th percentile).

5.4. Inter hour

The inter hour flexibility is then calculated based on the outcomes of commitment and dispatch and hydro scheduling modeling runs. Aurora was used to determine thermal generation and hydro dispatch across the region, while [Council tool] was used to determine hydro flexibility available based on maximum and minimum output in each month (April and August were both split in two). This was done for 80 years of data, to give 700,800 hours in the study. For each of those hours, the following process is followed to calculate flexibility available for horizons of 2, 3, 4, 6, 8, 10, 12 and 14 hour ahead:

- Determine thermal generation flexibility available assuming no change in commitment of generation, based on ramp rate, minimum generation and maximum output.
- Determine flexibility from offline generation (up ramp) or decommitting generation (down ramps). This is based on minimum up and down time, where up ramp is increased in those time horizons where a generator could come online. For those generators that are scheduled to

come online in the production cost model results accounted for by counting them as upwards flexibility when they come online.

- Determine flexibility from hydro generation, based on the difference between dispatch and maximum (for up ramping) and minimum (down ramping)

These three are added together to get a time series with flexibility available for each time horizon examined in each hour for the year. The next step is to compare this to what actually was used, to determine spare flexible capacity available. This is used as a way to calculate whether the system has sufficient flexibility available to meet ramping requirements. Calculations are shown for each month of the year and hour of the day, with average and min/max being shown for each.

The remainder of this section steps through each of the calculations made to assess flexibility. This uses an hourly production cost modeling run from Aurora for the Northwest region, with 80 years of hydro data, 1 year of wind and load data. Assumptions about generator characteristics were based on Aurora data at BPA. The hydro time series was provided from Aurora, with minimum and maximum outputs provided by the NWPCC modeling tool for each month of the 80 years.

Thermal Flexibility

First, flexibility from thermal generation is calculated. Online generation is assumed to be able to provide ramping equal to the minimum of the ramp rate over time horizon, or the difference between minimum and maximum output. As the time resolution is one hour, ramp rates are not binding (i.e. the generators can ramp between minimum and maximum in less than one hour). Therefore the amount of online ramping is the same for each look ahead. Ramping capability from online thermal generation is calculated as the difference between output and maximum stable generation (for upwards flexibility) and minimum stable generation (downwards flexibility). This is calculated for each hour of the simulation in multiple time horizons. That means, for the results given here, that upwards and downwards flexibility is calculated for each generator for each hour over each time horizon in the 80 years of simulations. This provides a matrix 700800 (number of hours) by 42 (number of generators) for each of 7 time horizons (2 hours to 14 hours in 2 hour steps).

An example is given below for flexibility from one of the generators. The blue line shows an installed capacity, red line shows the dispatch from the Aurora runs. Note that the unit comes off and back online in a shorter time frame than the min down time assumed here, such that calculation of offline flexibility may prove difficult for these analysis (the method is still valid, but more accurate data needed). The green line shows flexibility available online for all time horizons, which is the difference between dispatched power and installed capacity.

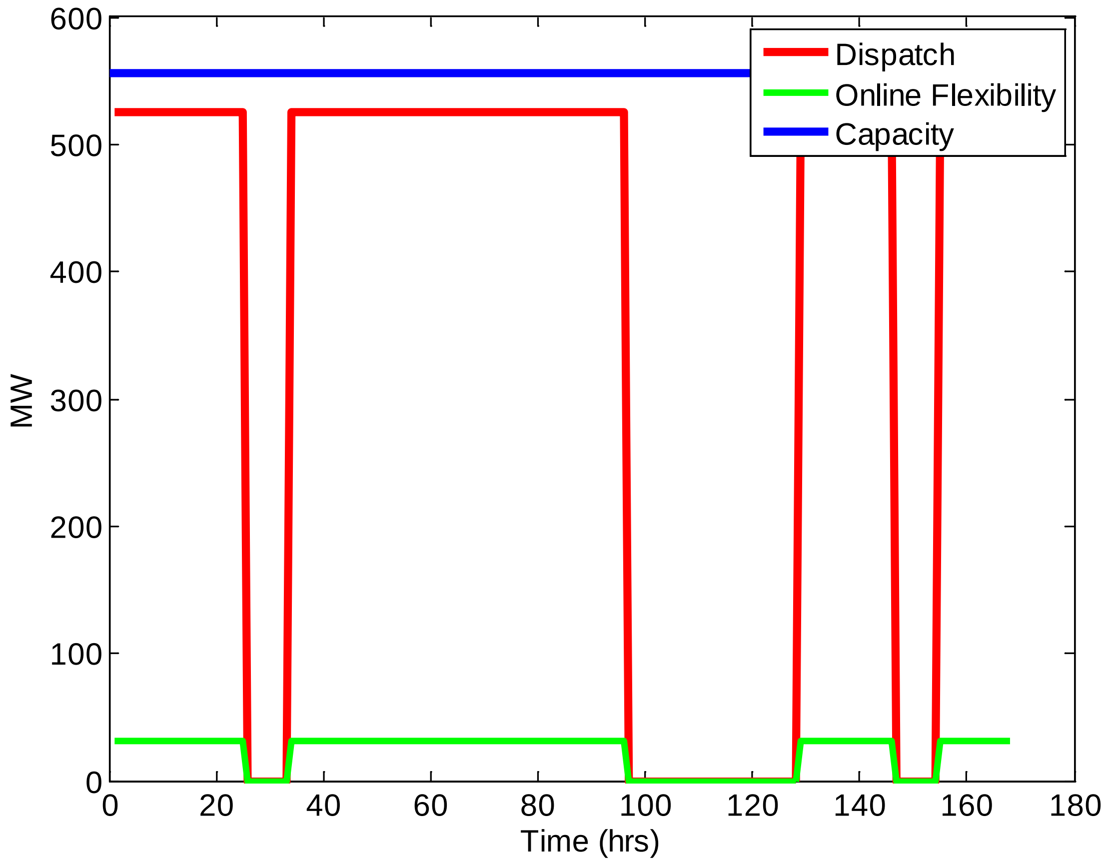

Figure 3: Generator Dispatch, Installed Capacity and Upwards Flexibility Available from online generation

Looking to offline capacity, the additional flexibility available when units are offline can be calculated for each time horizon and each hour for each generator, as shown in next figure – note this is shown with the dashed line which, when the generator is offline, is at the installed capacity level, showing that the generator, as it can come online quick enough, can provide its full installed capacity when looking out two hours or more ahead. This assumes that the generation can come online in its minimum down time, or based on when the production cost model turns it on, whichever comes sooner. For example, if the model was to turn a generator with 4 hour down time on at 15:00, then it would be able to provide 2 hour ramping from period 13:00. At noon, it could provide three hour ramping, but not 2 hour ramping, while before 11:00 it could only provide 4 hour and higher time horizon ramping. There would be no 2 hour ramping available at 1300 if the unit was not scheduled by the production cost model to turn on.

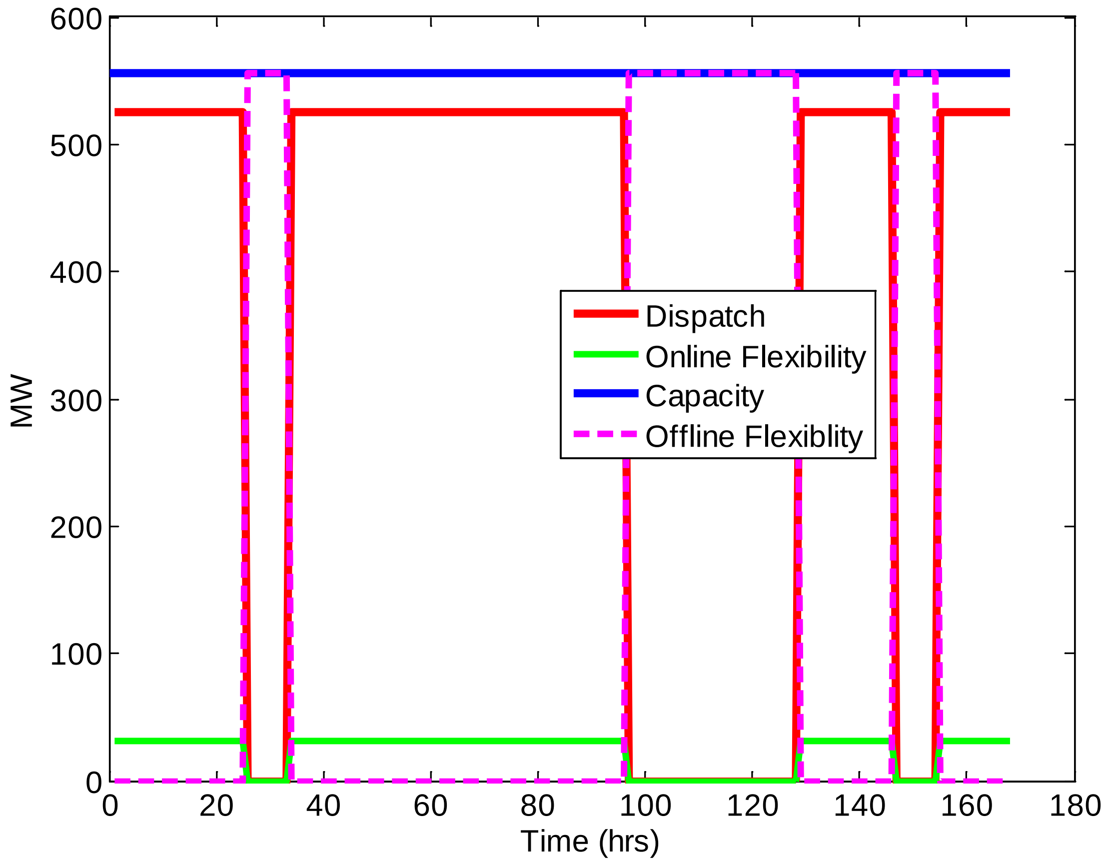

Figure 4: As previous figure, with upwards offline flexibility added

Similar calculations are performed for down ramping availability, as shown in the next figure. For online generation, the minimum generation is either the minimum stable level or zero, depending on assumed up time of generation, and whether the production cost model is about to turn off the generator; this is similar to the approach for upwards flexibility from offline generation.

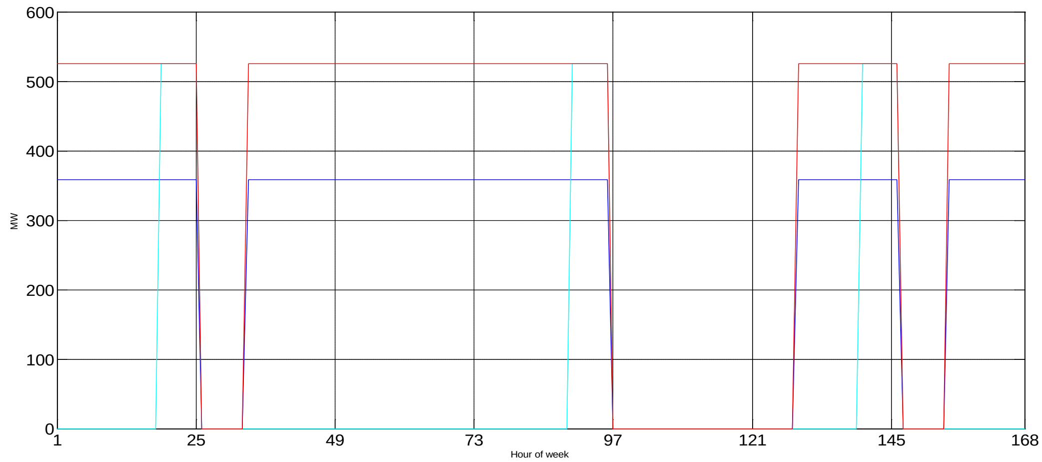

Figure 5: Downwards Flexibility Capability of example thermal plant

Here, the red line shows dispatch, the blue line shows how much ramping can be obtained by backing generator off to minimum output. The cyan line shows how much can be available due to the fact that the generator is about to turn off in the next hours. The cyan and blue line do not add (i.e. it is the maximum of the two that gets counted). Above figure shows 2 hour horizon.

The above calculations are performed for up and down ramping for all horizons. Below graphs summarize these calculations. The first shows the time series (80 years of 1 hour data) for available 2 hour up ramping from thermal generation. As shown there is always more than 0 MW, but often less than 500 MW.

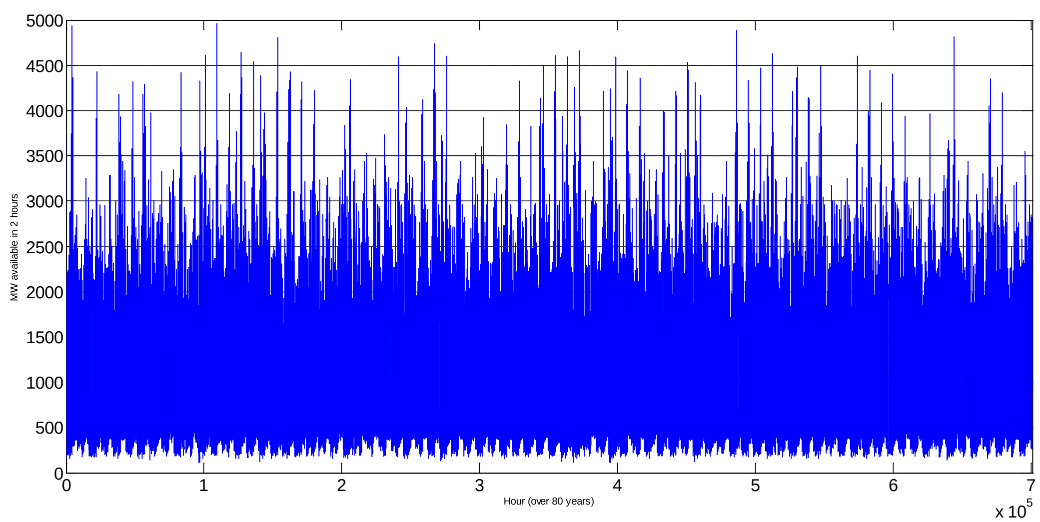

Figure 6: Upwards ramping available in 2 hours for thermal generation

The next graph shows a duration curve of the above and also the up ramping available from thermal generation over all other time horizons.

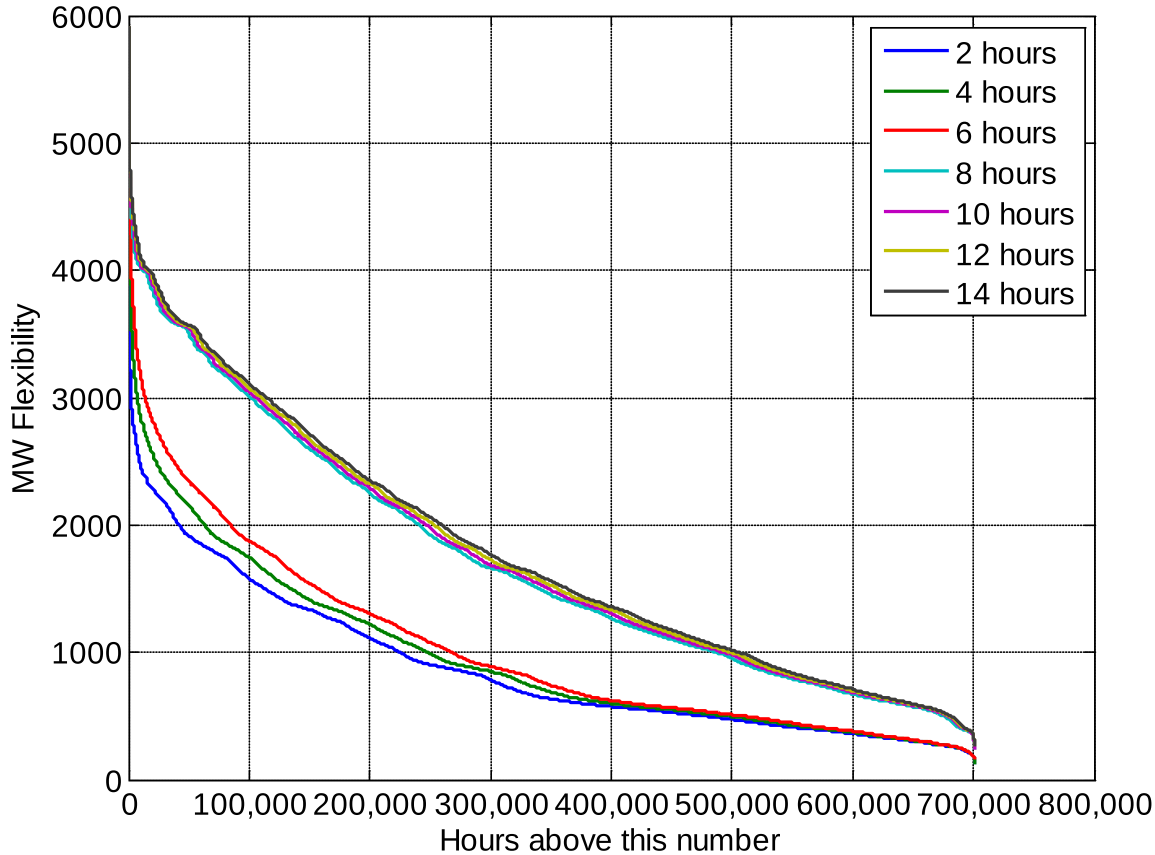

Figure 7: Duration curve of upwards flexibility from thermal generation based on 80 years of hourly data

As can be seen, there are essentially 2 shapes – the first (lowest) is for those under 8 hours start time; the second group is for 8 hours and over. This is due to assumptions about start time, where many generators can come online in more than 6 hours. The next graph shows the same for down ramping:

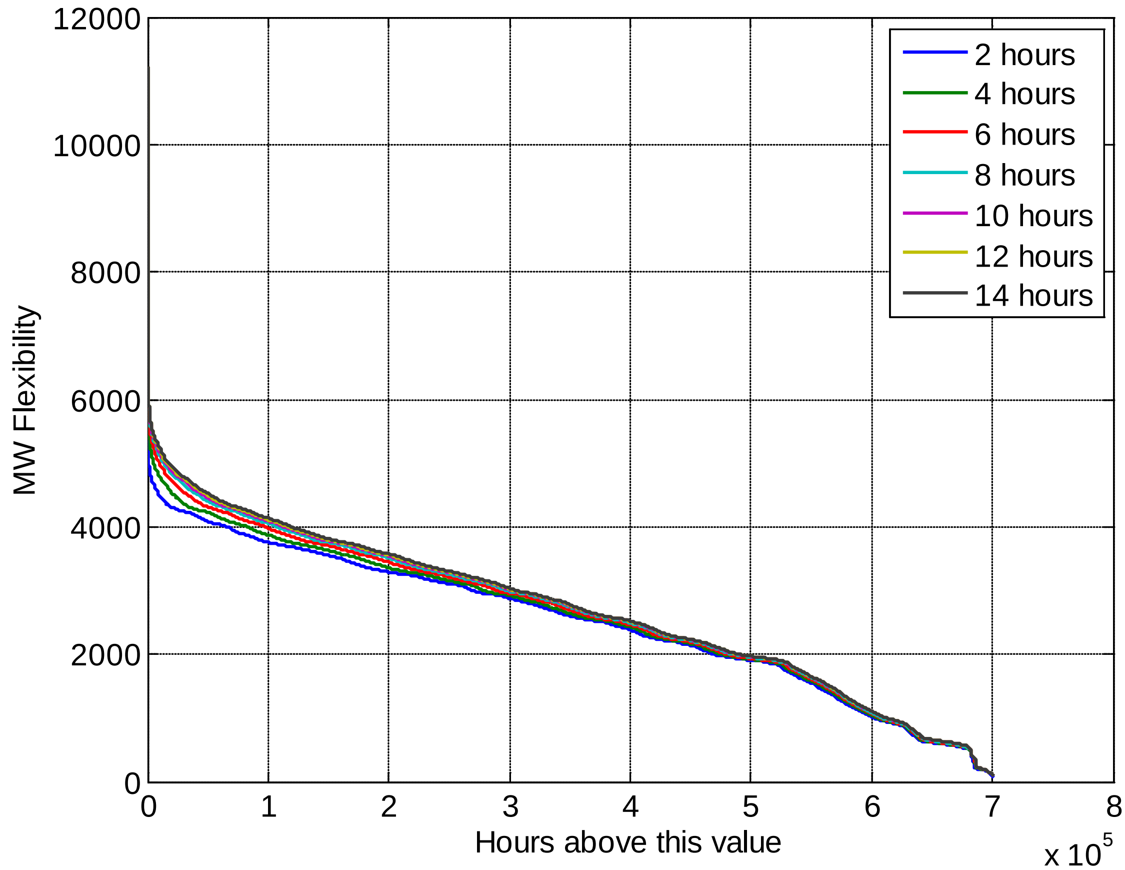

Figure 8: Duration Curve for downwards flexibility for thermal generation based on 80 years of hourly data

Here, it can be seen that there is very little difference between different time horizons for thermal capacity available. The slope is also steeper – there are more hours with high available ramping down, and fewer hours with little available. The total available ramping will be explored more in later figures once hydro has been added.

5.5. Hydro Flexibility

To add hydro flexibility, monthly values of maximum and minimum hydro capacity were calculated by NWPCC for each of the 80 years, with 2 values given for April and August. These gave different maximum and minimum available capacity for different look aheads – the idea being that if you only want to cover a two hour ramp, you can likely increase or decrease the hydro more than if you are looking at, say, a 10 hour ahead ramp. Taking the hydro output from the Aurora runs as the basis, the ramping capability of the hydro fleet for different time horizons was calculated. The up ramping capability is given as a duration curve in the following figure. Note that, compared to thermal generation where flexibility available increases with time horizon, here it decreases as the hydro generation availability decreases with time horizon due to its energy limited nature.

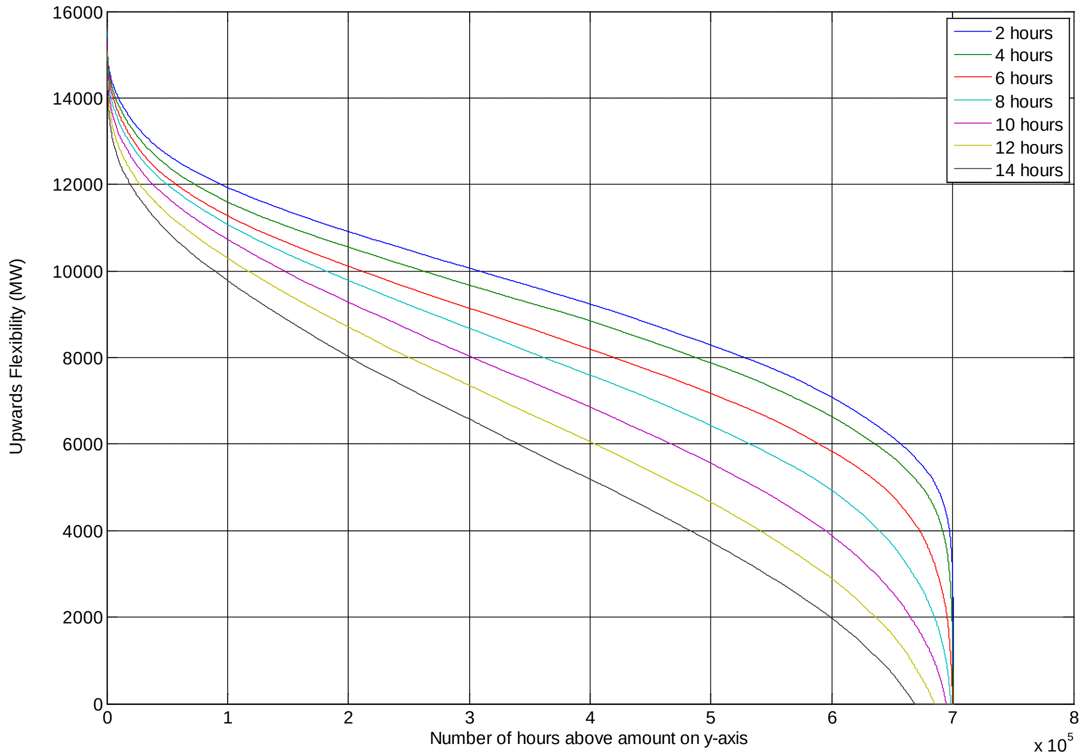

Figure 9: Available upwards flexibility form hydro for different time horizons based on 80 years of hourly data

As shown, there are certain hours when there is very little available from hydro, particularly over longer time horizons. This is due to hydro output being close to, or even slightly above, maximum output (due to inconsistencies between Aurora and hydro modeling). The lowest amount allowed in these calculations was zero MW (i.e. there was a floor of zero MW calculated), though there were a handful of hours with a ramping available being negative due to Aurora/hydro model inconsistencies, which are ignored here. A similar calculation was made for down ramping from hydro, showing less available:

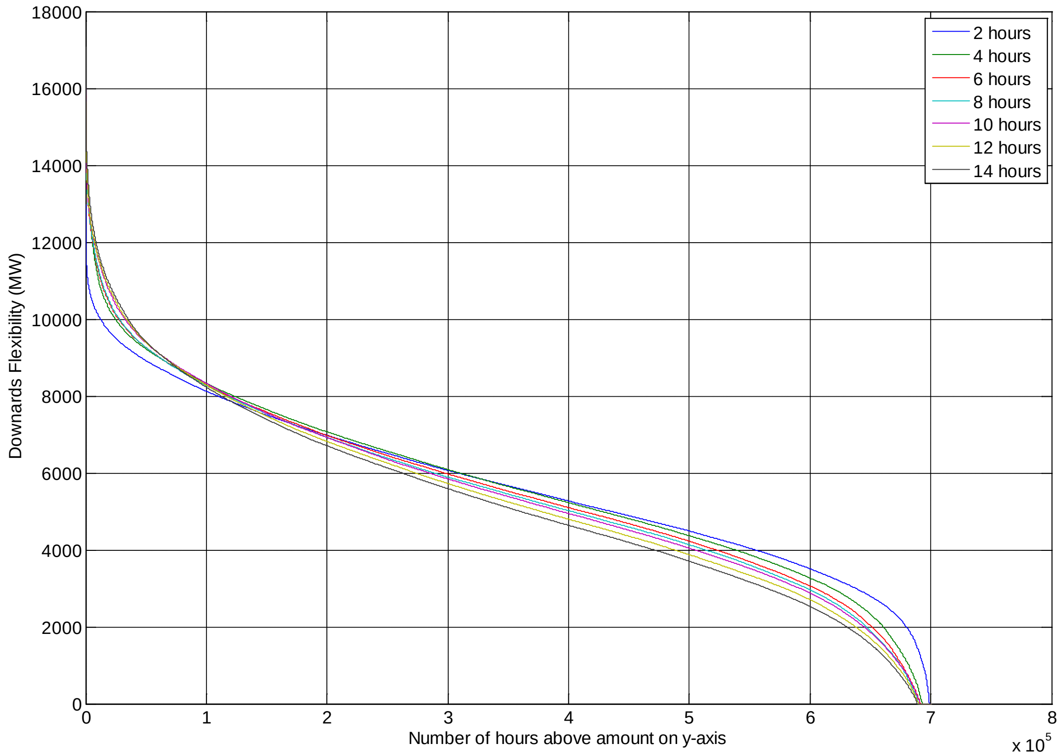

Figure 10: Downwards flexibility from hydro for different time horizons based on 80 years of hourly data

Here, the amount available did not change much across time horizons compared to the up ramping. This implies that downwards flexibility does not change as much depending on time horizon compared to upwards flexibility, and that examining different time horizons may be less relevant here.

5.6. Total Flexibility Available

Once the amount available from hydro and thermal was calculated, they could then be added. Below shows the amount available as a duration curve. The most available is over 16 GW; more interesting here is the least available. It can be seen in general that longer time horizons show lower available flexibility, due to the fact hydro dominates, and hydro flexibility decreases with horizon.

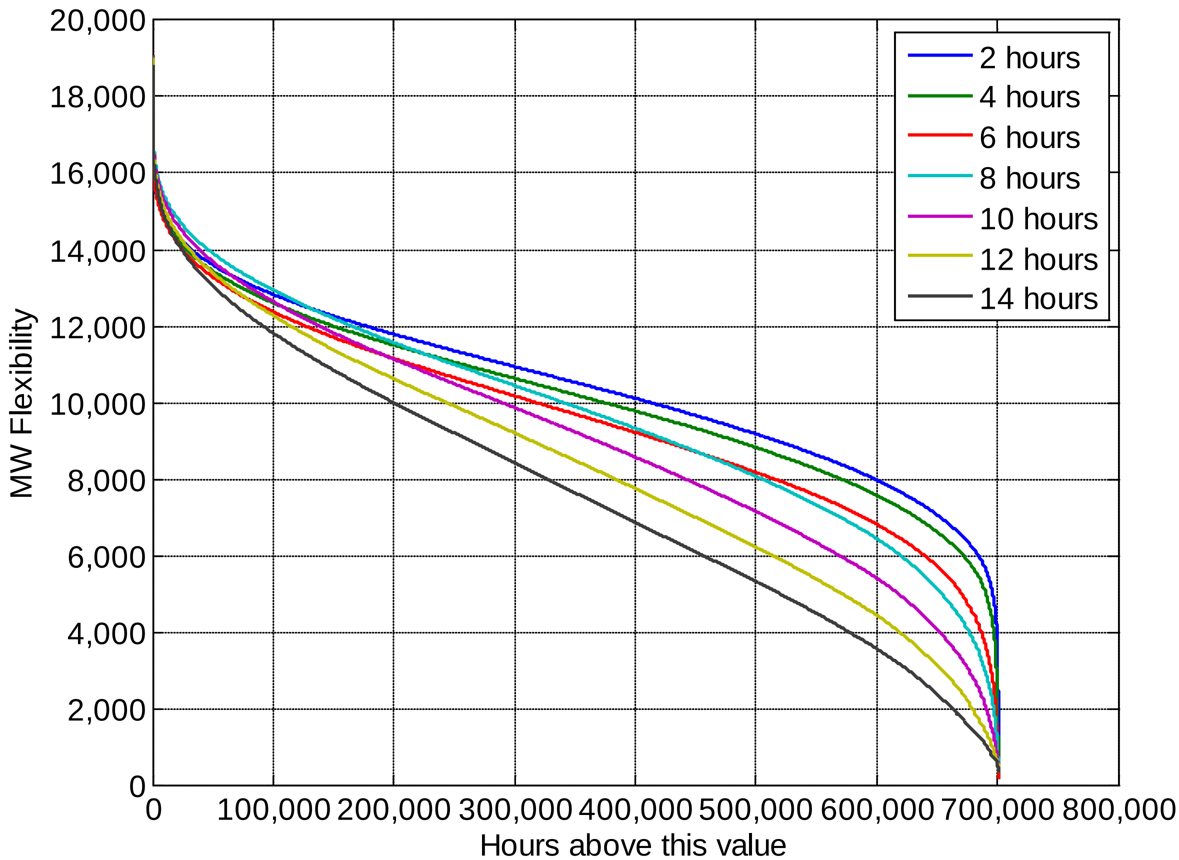

Figure 11: Total Upwards Flexibility available from thermal and hydro for different time horizons based on 80 years of data

Zooming into the area less than 2000 MW, the following can be seen:

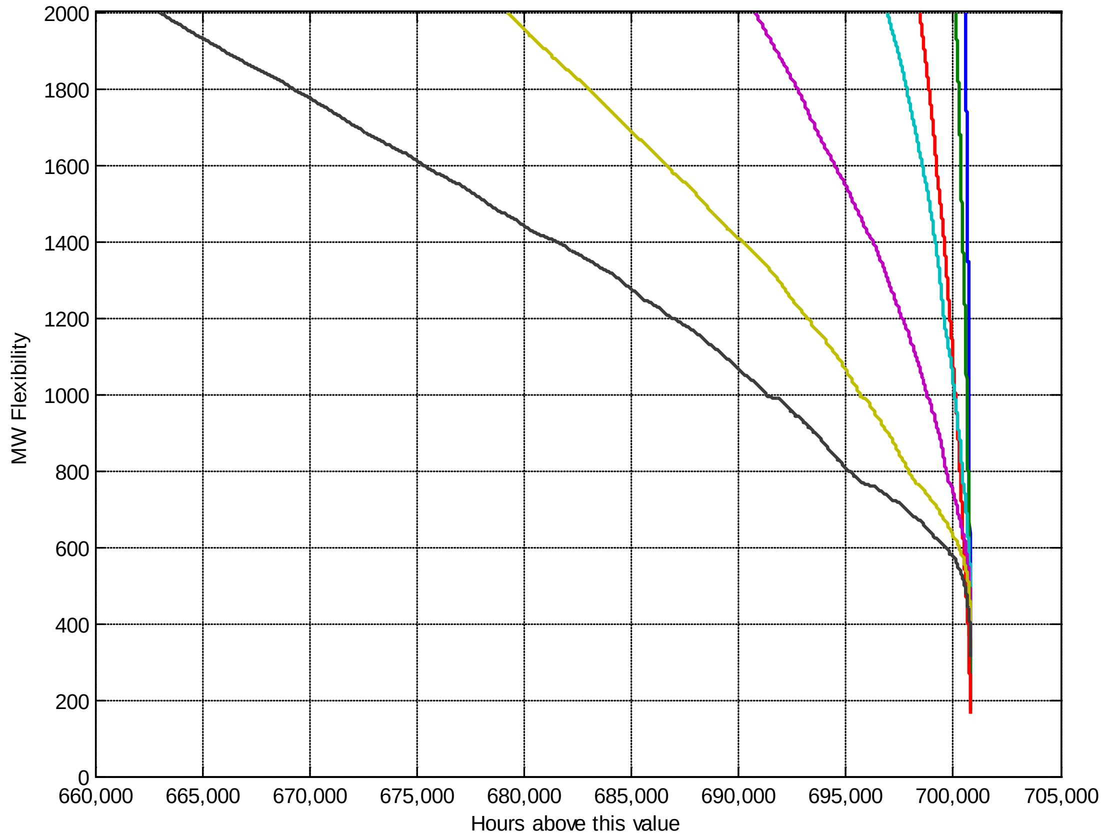

Figure 12: Total Upwards Flexibility for different time horizons, for periods with less than 2000 MW available

This shows that for approx. 8900 hours of the 80 year simulations (approx. 1.3%) there are less than 1000 MW of 14 hour up ramping capability in this fleet. There is less 1000 MW of capability for 4575 hours (0.6%) for 12 hours, and less again for 10 hours (1440 hours/0.2%) and 8 hours (159 hours/0.02%). For shorter time periods, there are less than 100 hours when less than 1000 MW of upwards flexibility is available.

The next figure shows the available ramping upwards capability in a 2 hour period by month with each hour represented by a box plot. This shows that the mean and media amount available varies by month, with the least available during April-August .Note the very lowest is not shown here, only the 9^{th}-91^{st} percentiles using the whisker plots; these show that except for less frequent events there is always more than 5 GW available

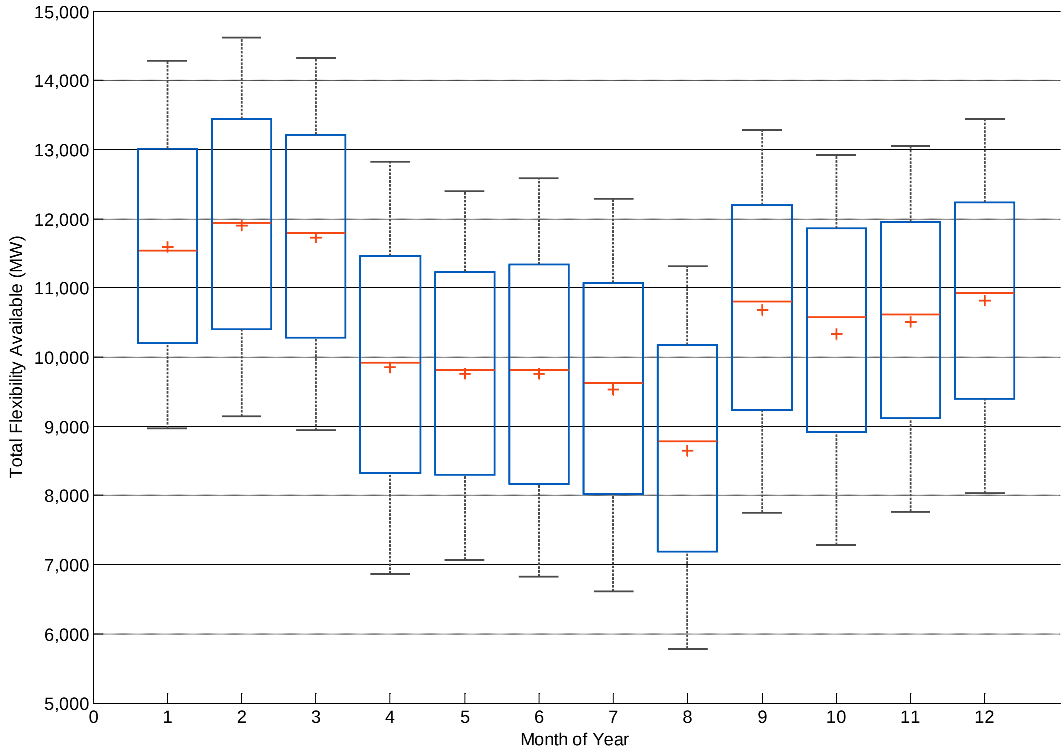

Figure 13: Box Plots for available upwards 2 hour flexibility by month. The box shows the 25th to 75th percentile of data, the whiskers show 9th to 91st percentiles, the line shows mean and the cross shows the median

The same figure for 12 hour ramping shows a very different result. Here, September and October show the least amount of 12 hour upwards ramping, while May shows the most. This is due to the nature of the hydro flexibility, with the decrease in amount available being more important in the fall months. It also shows that the amount available is closer to zero for longer time horizons for certain months.

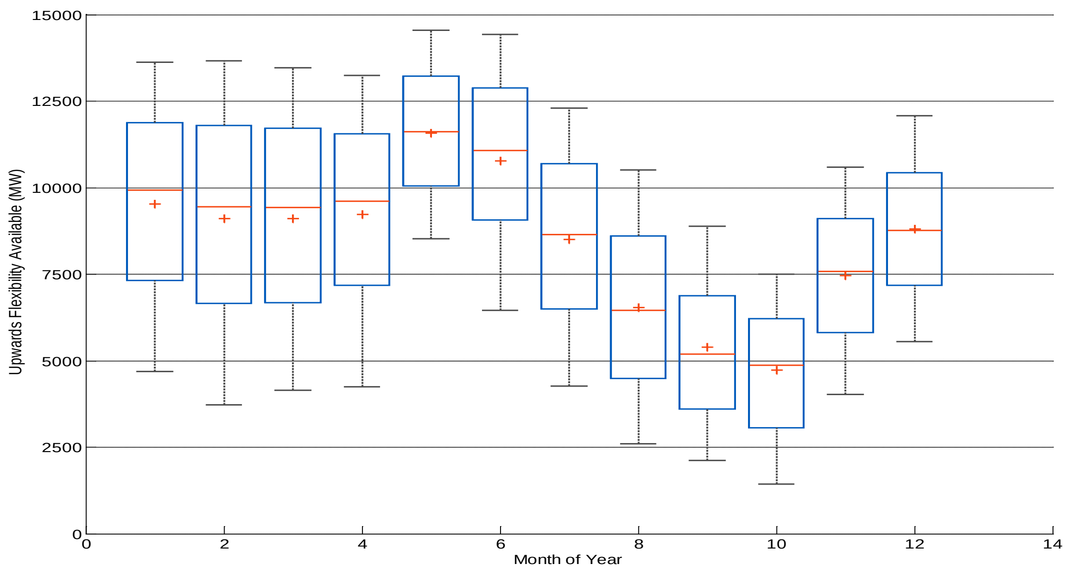

Figure 14: Box plots of available 10 hour upwards flexibility by month.

For hour of day, there is slightly more up ramping available during the night than during the day, as expected. Most of the hours there are very similar, mean median and extreme values available.

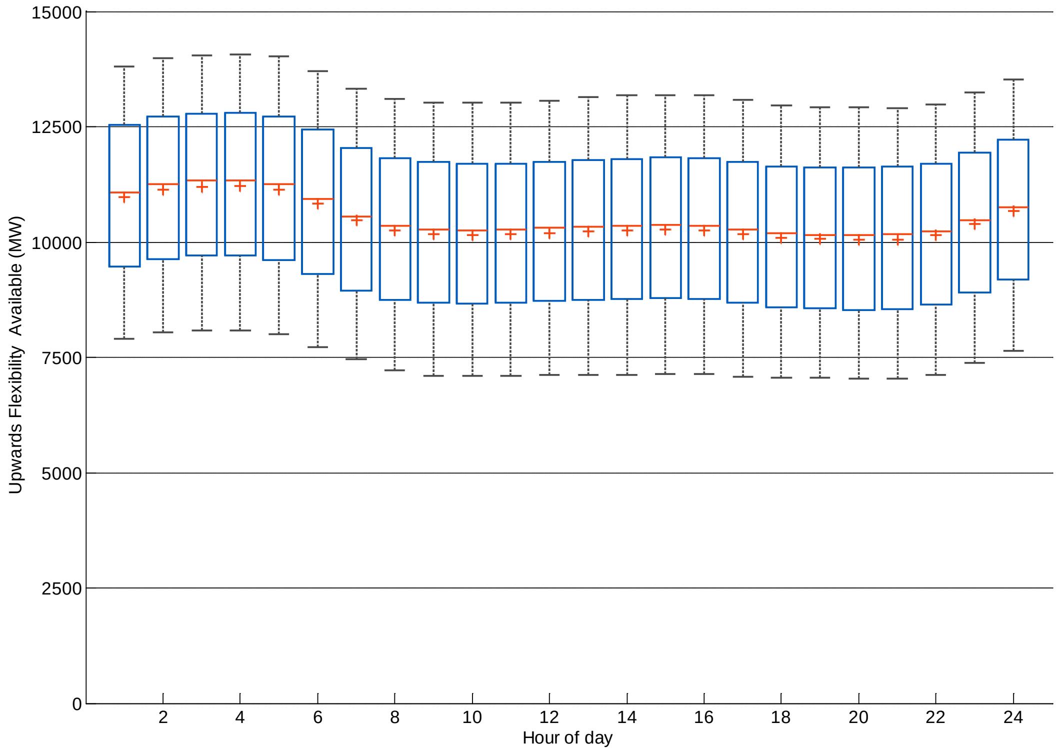

Figure 15: Box plots of 2 hour upwards available flexibility by time of day

The same treatment as above is given to downwards ramping in the next figures. The following shows that less downwards is often available than upwards, but there is less difference between time horizons.

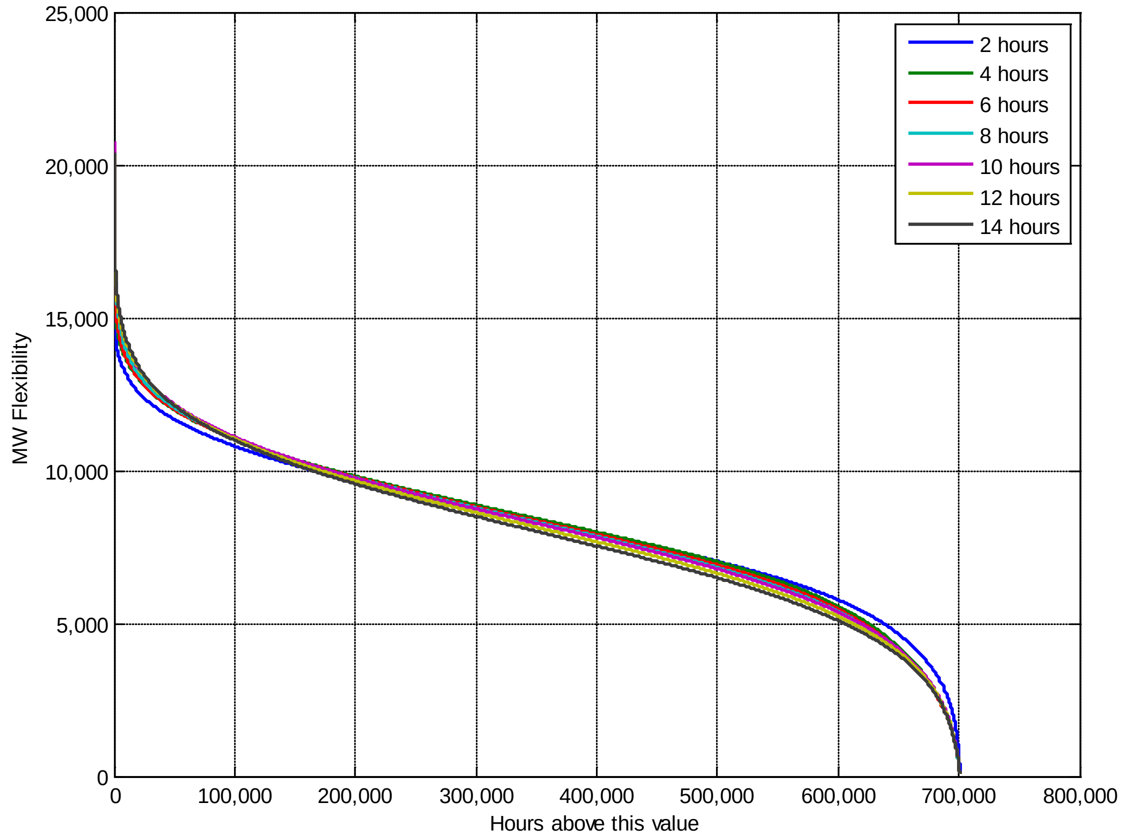

Figure 16: Downwards Ramping Availability duration curve

For this, there are no values less than 1000 MW, so it is not shown. Finally, the monthly look shows how things vary over time of year for 2 hour and 12 hour ramping. April-June shows the most binding periods where downwards flexibility is lower, but downwards ramping is not very constrained. 2 hour downwards flexibility can be seen to have more available in general compared to 12 hours.

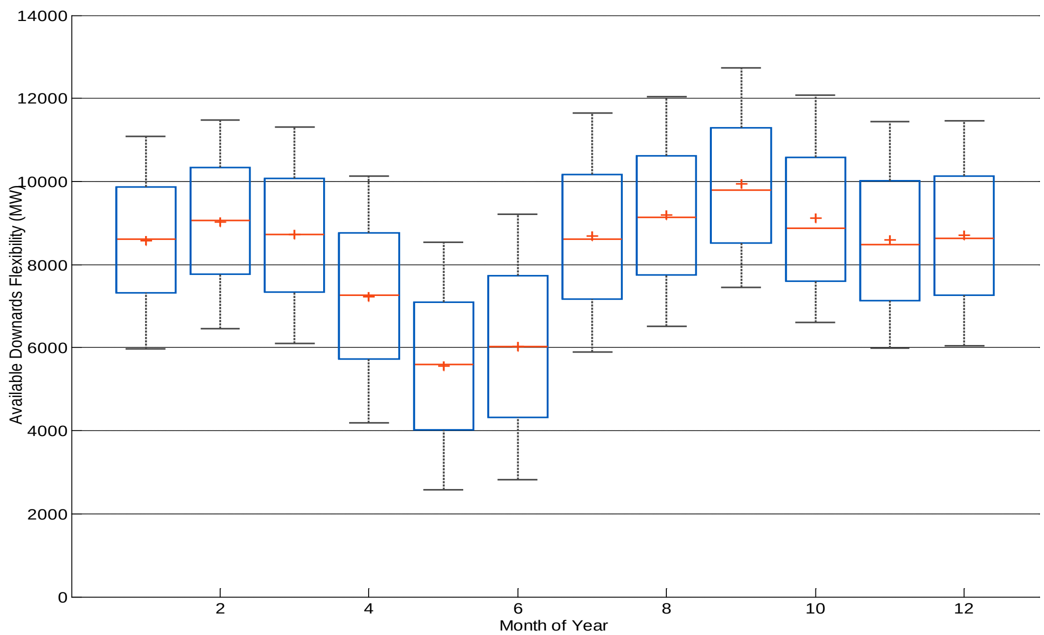

Figure 17: Box plots showing Monthly Available 2 hour downwards flexibility based on 80 years of data

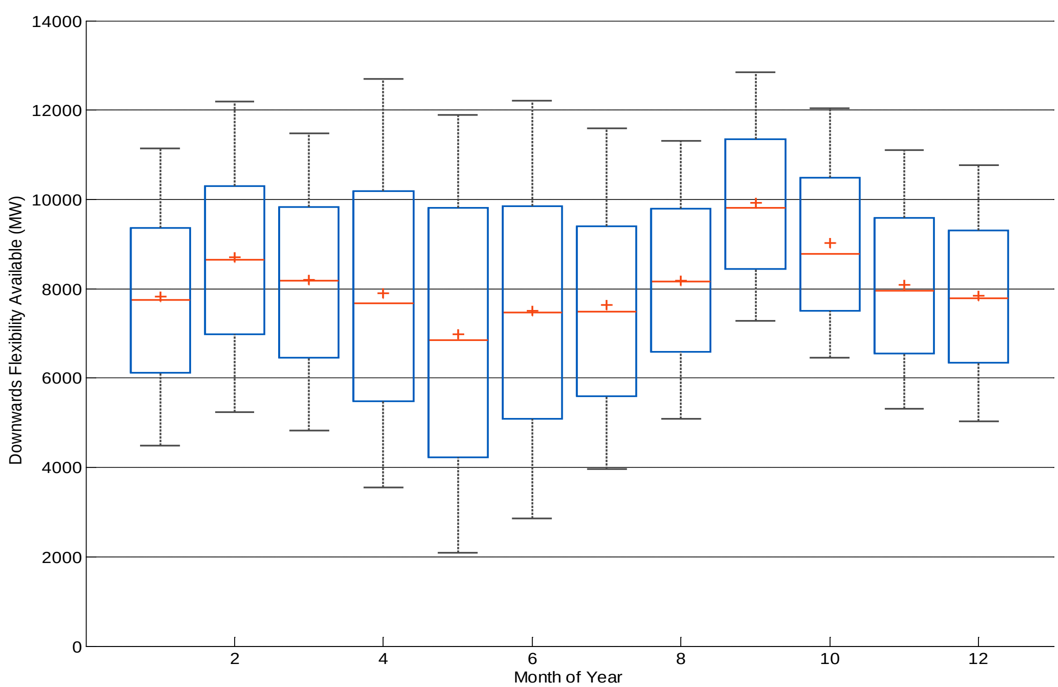

Figure 18: Monthly Available 12 hour downwards flexibility based on 80 years of data.

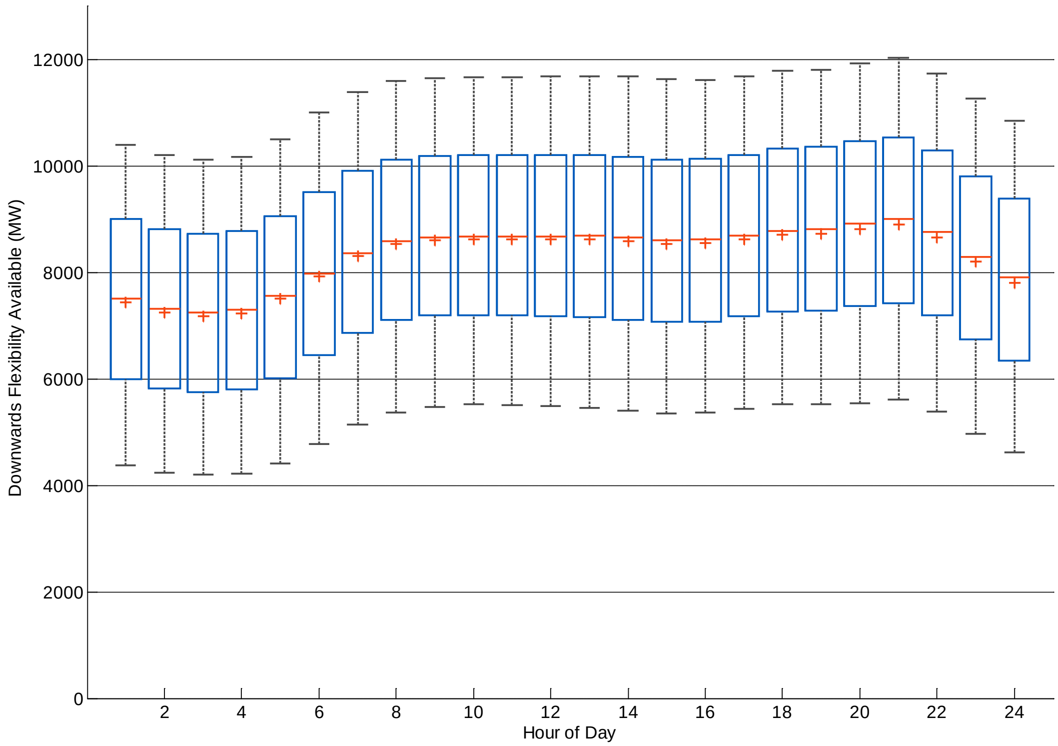

Figure 19: Hourly Available 2 hour Downwards Flexibility based on 80 years of data

The above figure shows hourly flexibility on a 2 hour horizon can be seen to be slightly higher during the day. Looking at the next two figures, it can be seen that there is significant variation in the amount of available flexibility for a given hydro year. The range of mean values varies between 9 GW to 12 GW upwards, and approx. 6.5 GW to 10 GW downwards. The outliers and interquartile range show even greater available flexibility range. As would be expected, note that there is some relationship between those years where downwards flexibility is lower than usual and upwards is high, and vice versa.

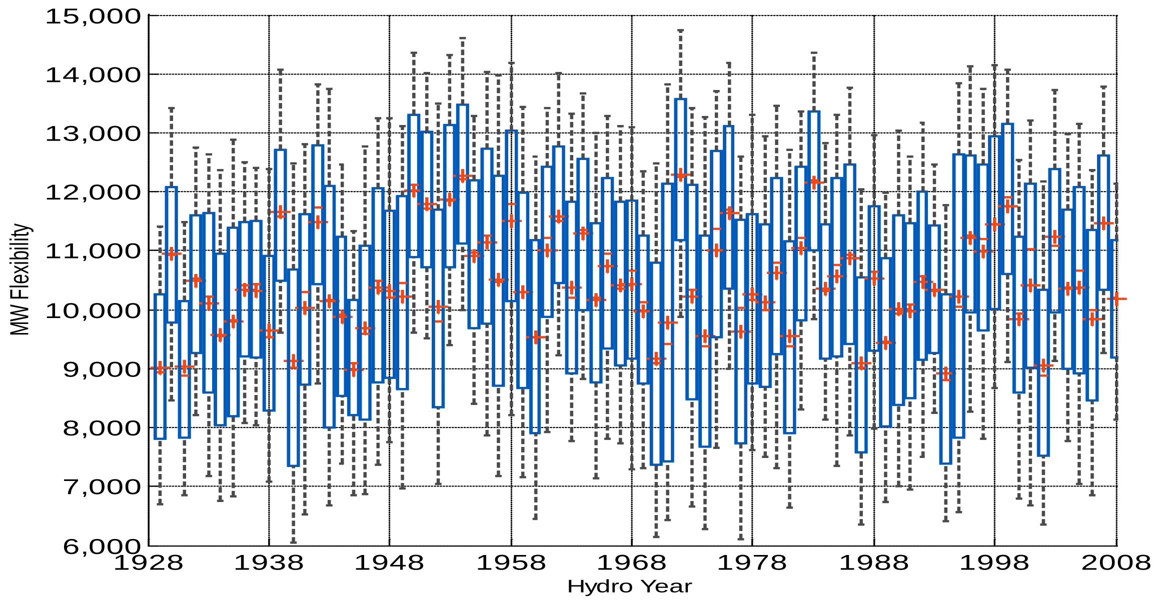

Figure 20: Two hour available upwards flexibility by year of analysis

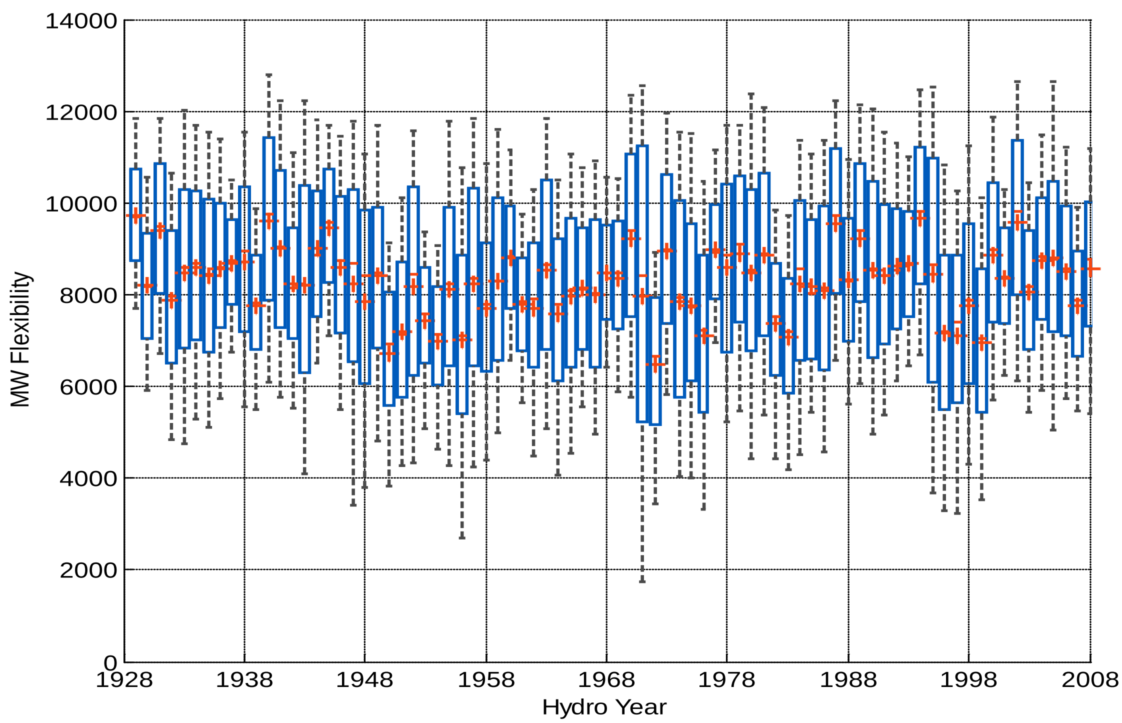

Figure 21: Two hour available downwards flexibility by year of analysis

5.7. Total Flexibility Utilized

Now that total capability has been calculated, the next step is to assess what was actually required. This was done separately for thermal and hydro generation, before being added together. The duration curves below show the actual ramps over different time horizons. The actual flexibility used for thermal generation is shown below. As can be seen the amount required is normally significantly lower than that available (though what is important is how the time series compare when synchronized, as calculated in the next section). As before, the actual numbers here are less important than the method used to examine the data, as data is likely to be updated with newer data for real studies. Up ramping is shown first, then down ramping.

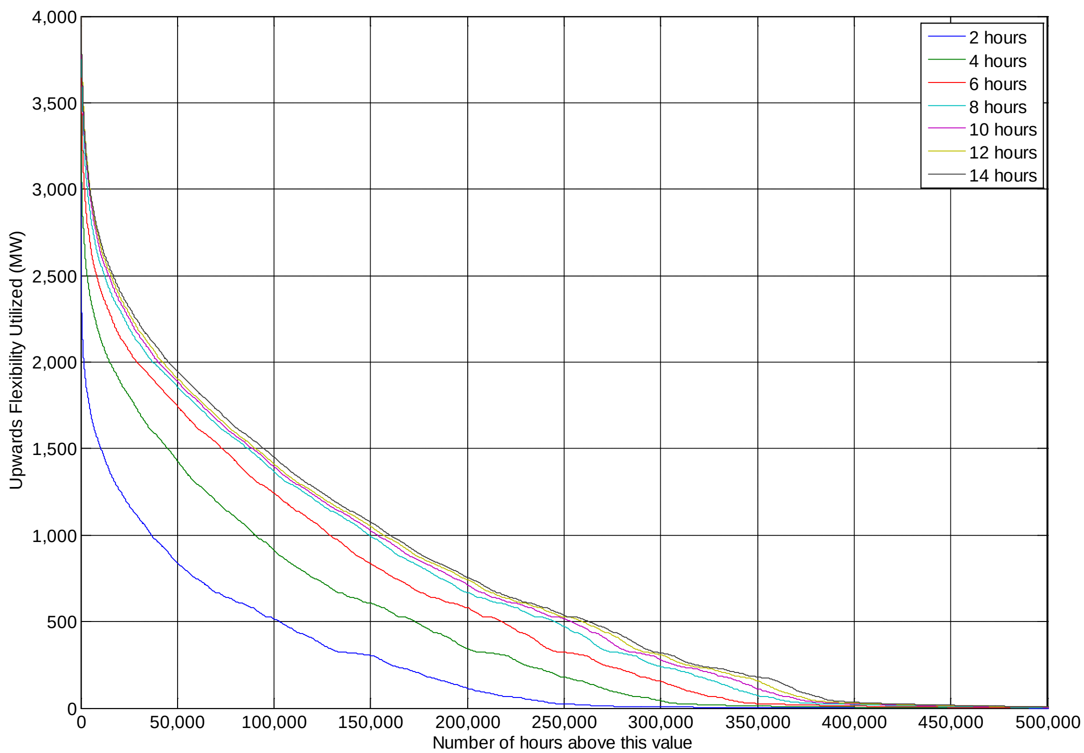

Figure 22: Duration Curves of Upwards Ramping Actually Deployed on Thermal Generation based on 80 years of hourly data

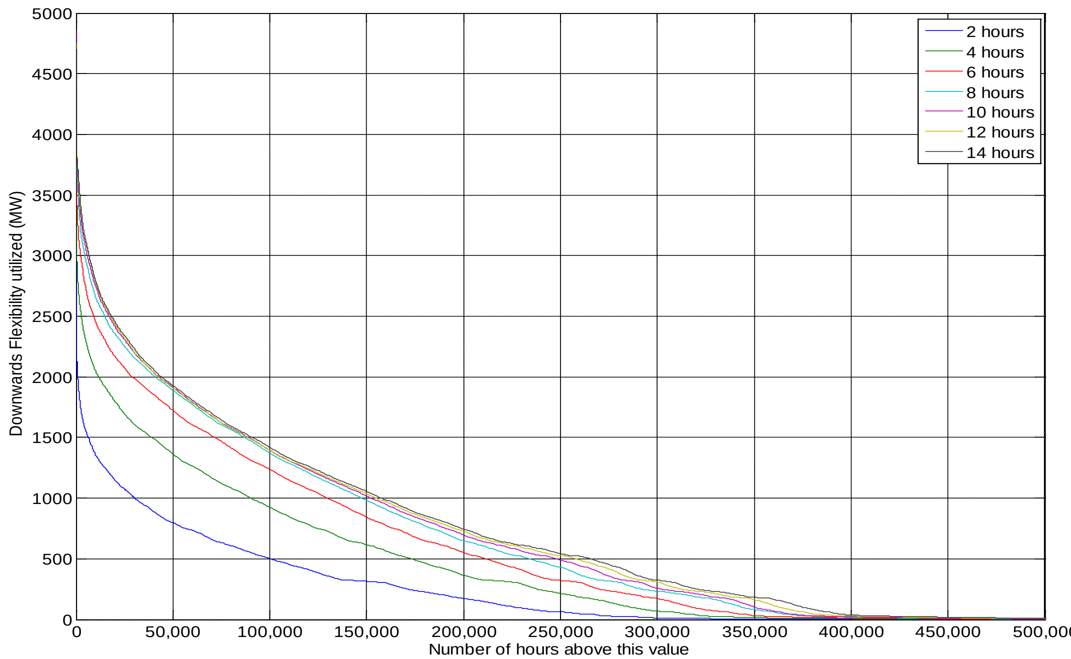

Figure 23: Duration Curves of Downwards Ramping Actually Deployed on Thermal Generation based on 80 years of hourly data

The same thing is calculated for hydro ramping required – duration curves for up and down ramps are as follows. Note the different scales compared to thermal, as far more flexibility is available from hydro.

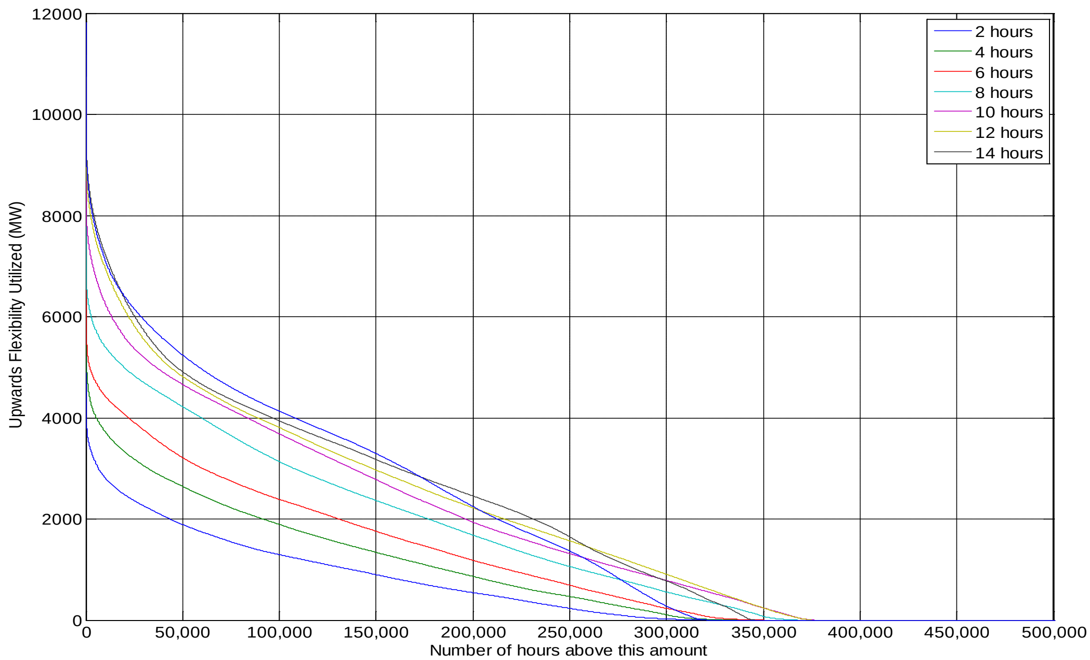

Figure 24: Duration Curves of Upwards Ramping Actually Deployed on Hydro Generation based on 80 years of hourly data

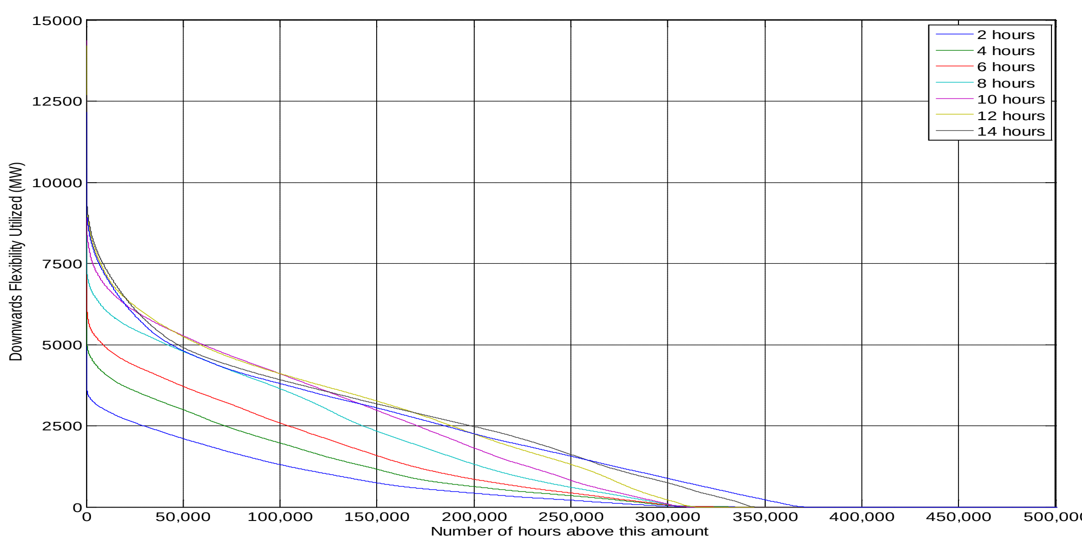

Figure 25: Duration Curves of Downwards Ramping Actually Deployed on Hydro Generation based on 80 years of hourly data

Up ramping shows the largest 2 hour ramp is a little less than 4,000 MW, with increasing ramp sizes versus time horizon. Down ramping required flexibility is very similar to up ramping for hydro.

Summing hydro and thermal, the following actual capability is required (up ramping duration first, then down).

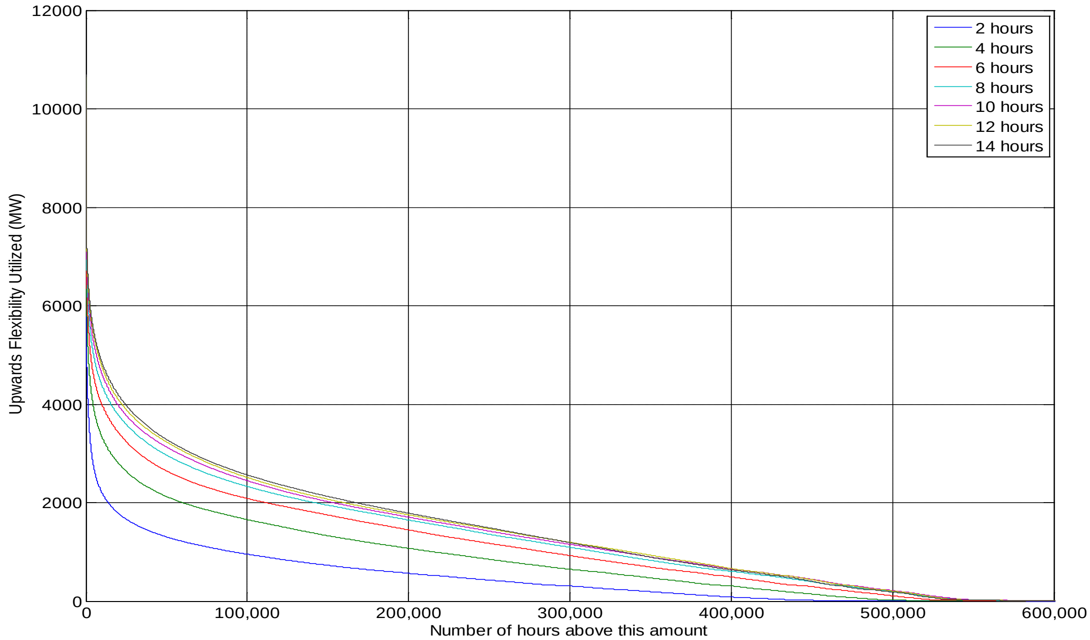

Figure 26: Duration Curves of Upwards Ramping Actually Deployed on Thermal and Hydro Generation based on 80 years of hourly data

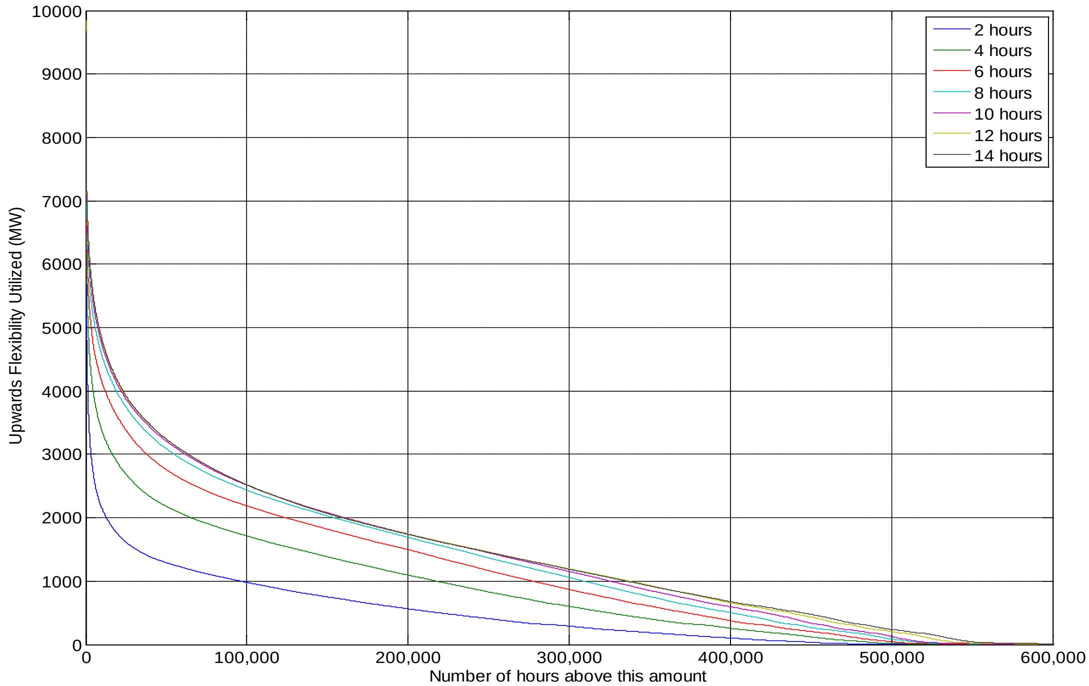

Figure 27: Duration Curves of Downwards Ramping Actually Deployed on Thermal and Hydro Generation based on 80 years of hourly data

As before, this shows total required is a lot less than available on average, however it is what happens in particular periods that is of most interest. Looking by month of year, and 2 hour up ramping, shows July and August with the highest amount of required ramping. As expected, there are many periods with no up ramping required, so the box plots go to zero. Similarly, July and August show the greatest need for 2 hour downwards ramping, as the load changes are largest then.

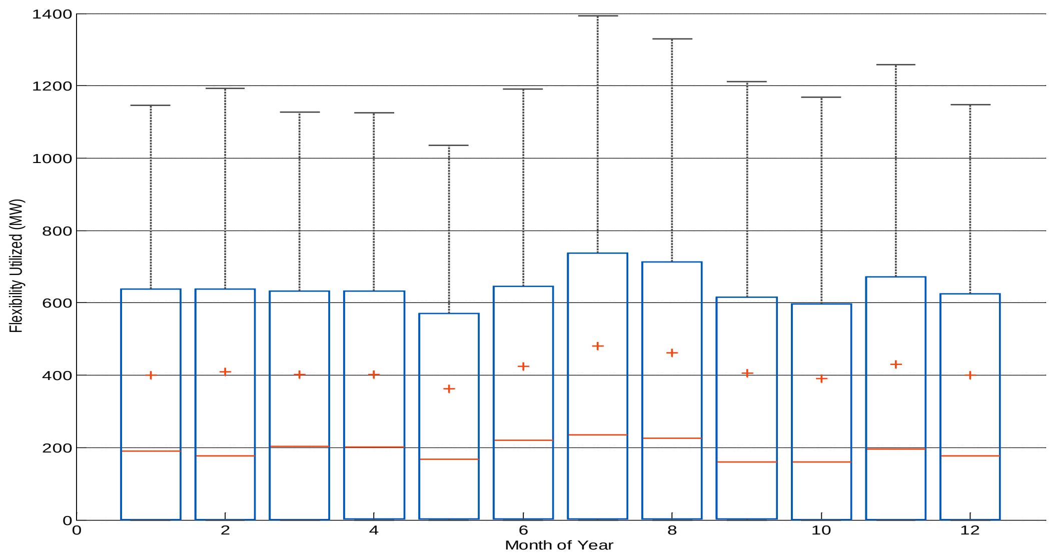

Figure 28: Box plots showing mean (line), median (cross), 25th/75th percentiles (box) and 9th/91st percentiles (whiskers) for 2 hour upwards ramping deployed by month

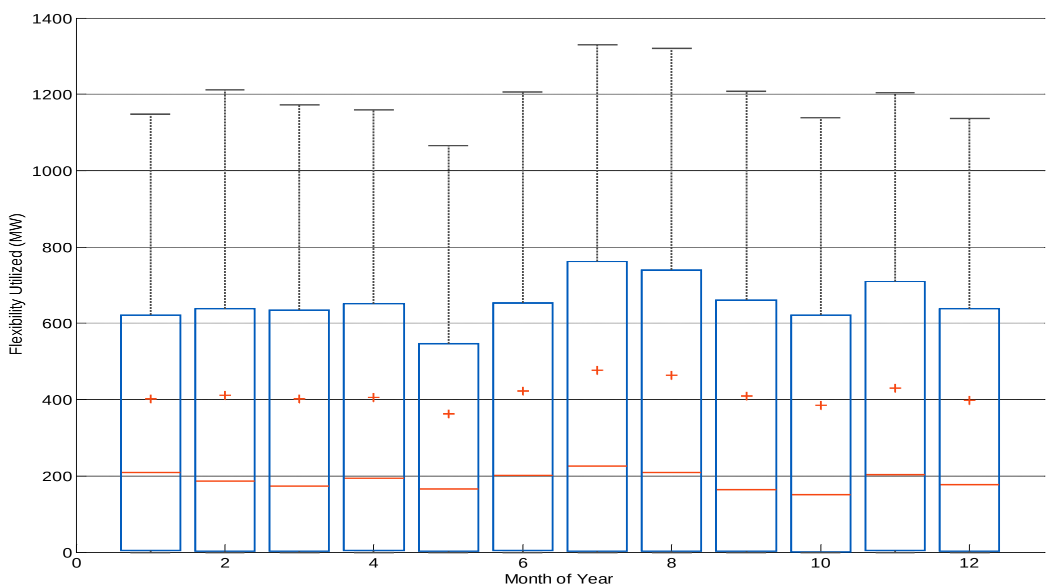

Figure 29: Box plots showing mean (line), median (cross), 25th/75th percentiles (box) and 9th/91st percentiles (whiskers) for 2 hour downwards ramping deployed by month

By hour of day, 2 hour up ramping is seen to be greatest at 5am, as expected (generators will need to ramp up until 0700 the following day); other than during the night, there are many periods with a zero flexibility requirement. 12 hour up ramping requirements are significantly different, with higher requirements during the night.

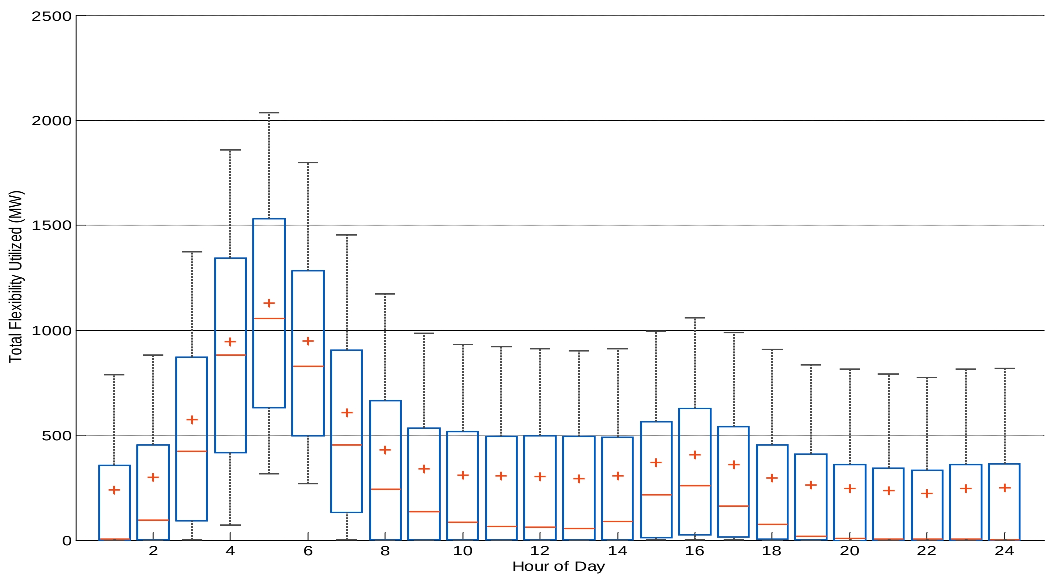

Figure 30: Box plots showing mean (line), median (cross), 25th/75th percentiles (box) and 9th/91st percentiles (whiskers) for 2 hour upwards ramping deployed by hour

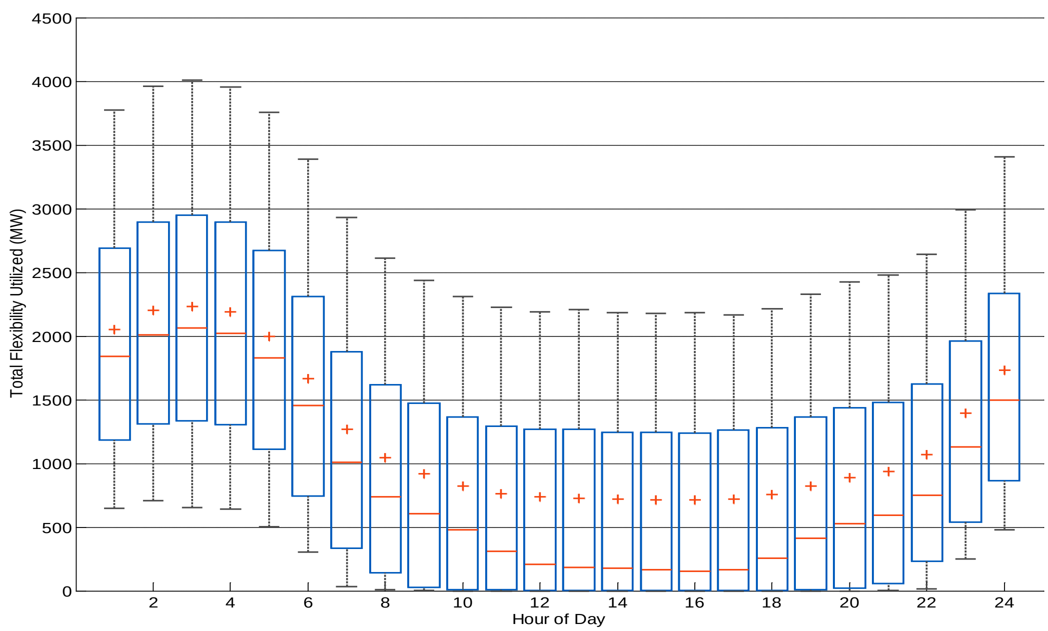

Figure 31: Box plots showing mean (line), median (cross), 25th/75th percentiles (box) and 9th/91st percentiles (whiskers) for 12 hour upwards ramping deployed by hour

2 hour down ramping is seen to be greatest around the evening, as expected. This is particularly high around 10pm. 12 hour downwards ramping is highest in the afternoon.

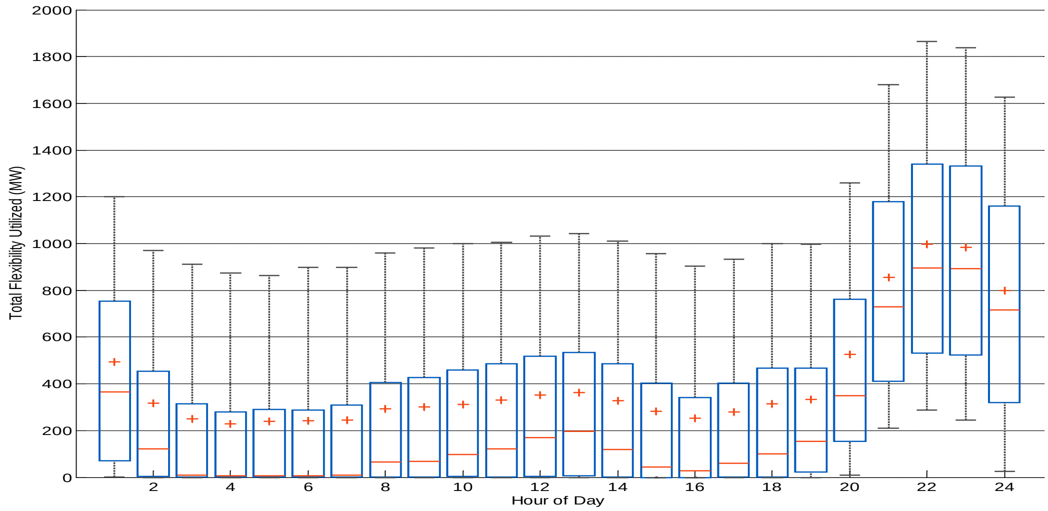

Figure 32: Box plots showing mean (line), median (cross), 25th/75th percentiles (box) and 9th/91st percentiles (whiskers) for 2 hour downwards ramping deployed by hour

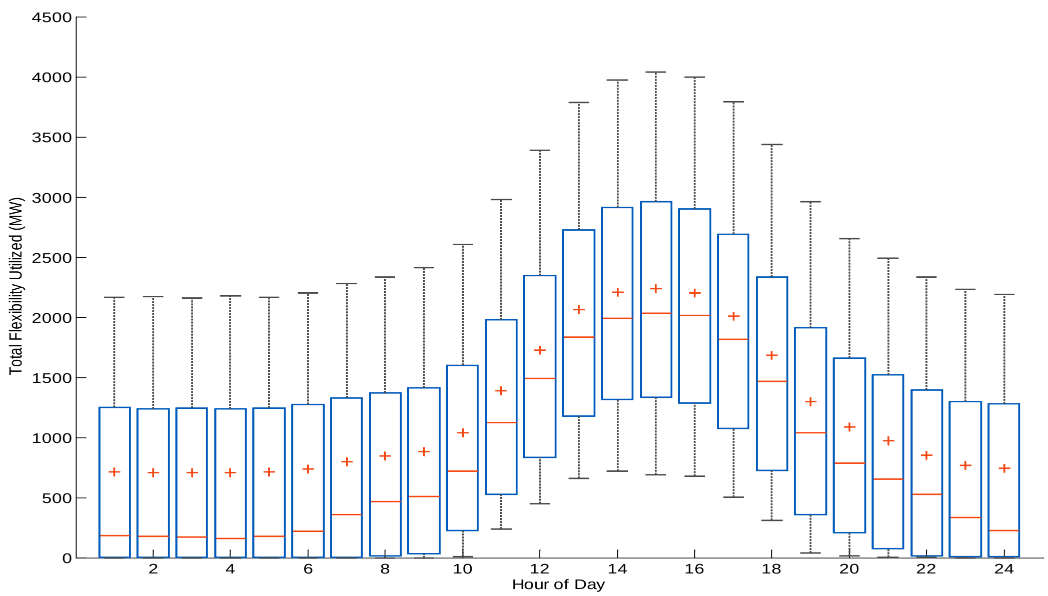

Figure 33: Box plots showing mean (line), median (cross), 25th/75th percentiles (box) and 9th/91st percentiles (whiskers) for 10 hour downwards ramping deployed by hour

Looking at this data by hydro year shows very little variation of mean, median, interquartile range or outliers. This section showed how required ramping should be calculated and understood. This can be important to understand how the flexibility on the system gets used.

5.8. Capability versus flexibility utilized – examining flexibility constraints

The final calculation is to determine the difference between what is available and what was actually required in each hour of the 80 years. This will indicate how close the system is to having insufficient flexibility. Obviously, assumptions about minimum up and down time of thermal generation, and consistency between the hydro modeling in the production cost model and the hydro modeling to determine maximum and minimum are important, such that these results are draft. However, they demonstrate how this method could be applied. So the numbers here are only useful as a means to understand the method. It should also be noted that due to the nature of the simulations, it would not be expected to actually run out of flexibility (though this will happen for a few hours when the hydro model and production cost model do not use exact same hydro outputs). So the main purpose of examining in this way is to determine whether the system will be closer to not having sufficient flexibility. With increasing variability, this number may increase, and should be tracked.

This is calculated for thermal only, hydro only and the combination, to determine where and how flexibility is being provided. The first thing to examine is the duration curves, as before. Below shows duration curves for spare thermal capability in upwards direction:

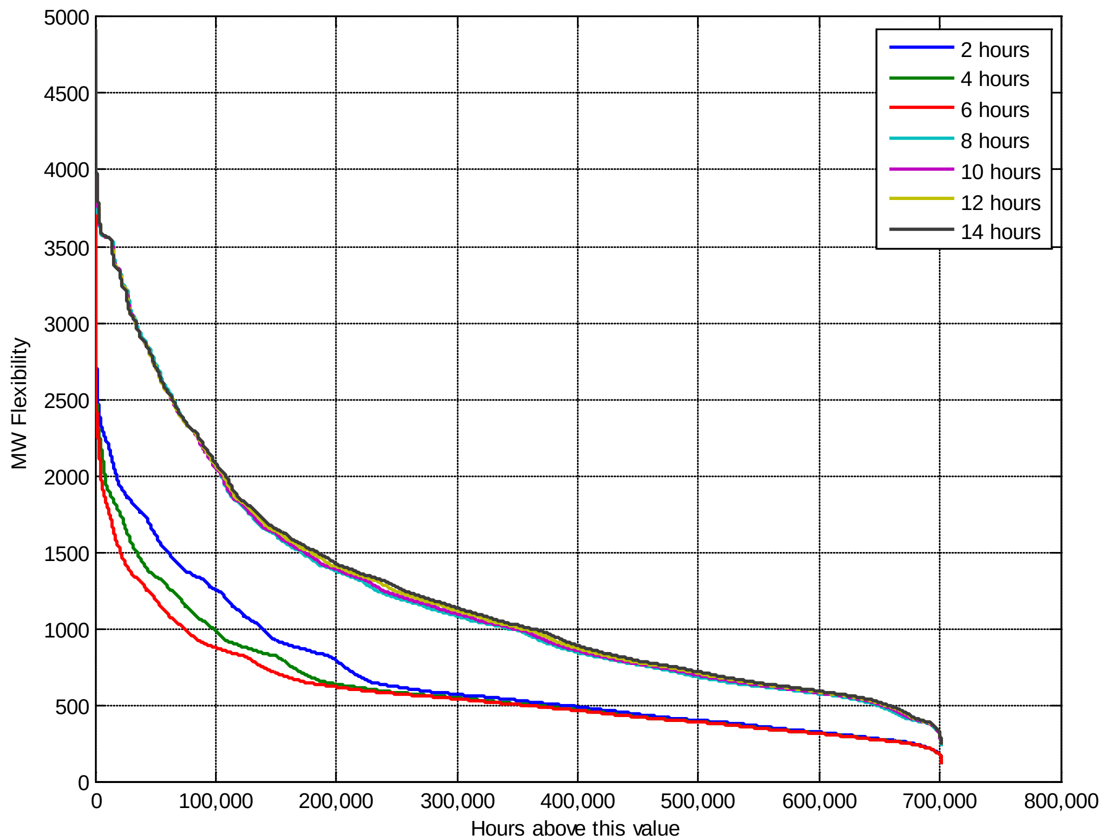

Figure 34: Duration Curves for Spare Upwards Flexibility on thermal generation when Utilized Flexibility is subtracted from Available, over 80 years of hourly data

As shown, there are a large number of hours when ramping on different time horizons is less than 500 MW. In particular, 6 hour shows the least amount of spare capacity, while 8 hours plus does not show as large a shortfall. This would be expected from earlier results, where 2-6 hours are the lowest amount available, with 6 hours having a higher requirement than 2 hours or 4 hours.

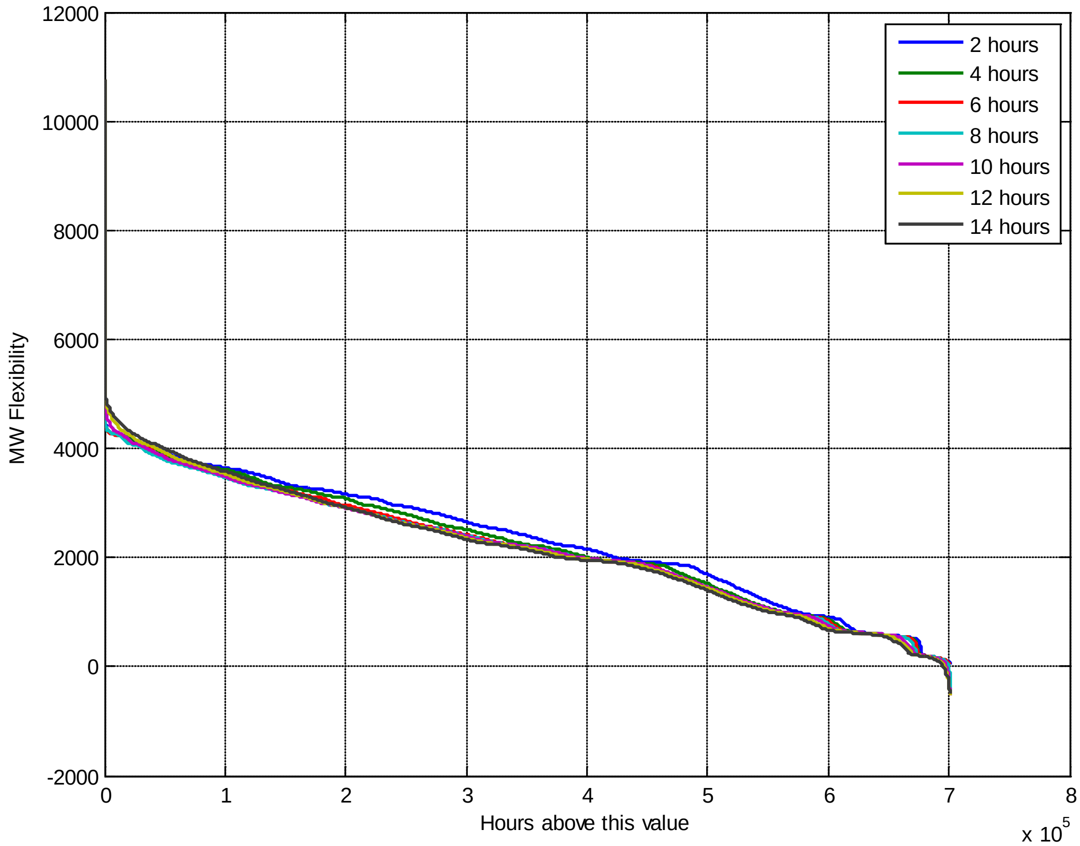

Figure 35: Duration Curves for Spare Downwards Flexibility on thermal generation when utilized flexibility is subtracted from available flexibility, for thermal generation over 80 years of hourly data

This shows most of the time horizons have similar amount of spare downwards flexibility from thermal generation; again this may be expected from earlier results. There are a number of hours when downwards thermal capability is a little lower than zero MW. Looking at hydro shows the following two figures for up and down spare capacity. As can be seen, the capacity available after requirements are met are further spread out for upwards than downwards, as would be expected from the available hydro capability. 14 hours shows the lowest amount of spare capacity, due to the energy limited nature of the resources. For downwards capacity, there is very little different, but again 14 hours shows the lowest amount of spare capability once actual ramps are subtracted from available flexibility.

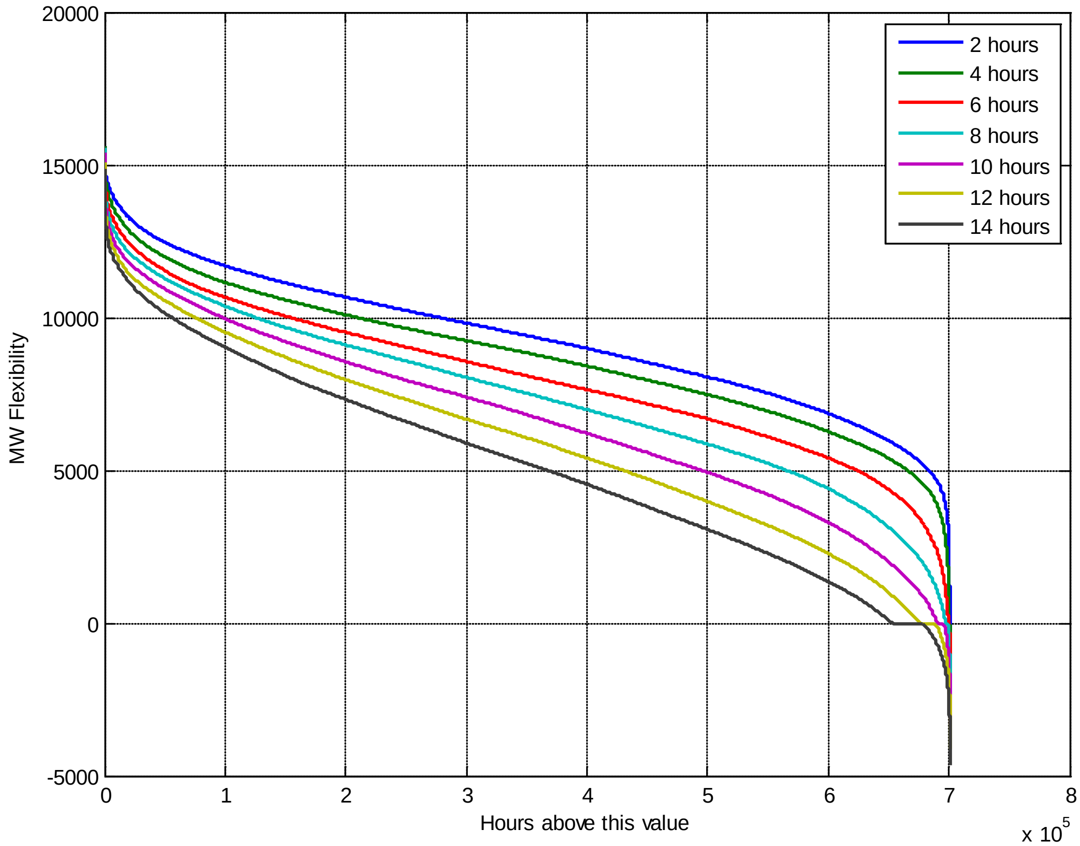

Figure 36: Duration Curves for Spare Upwards Flexibility when utilized hydro flexibility is subtracted from available hydro flexibility, for hydro generation over 80 years of hourly data

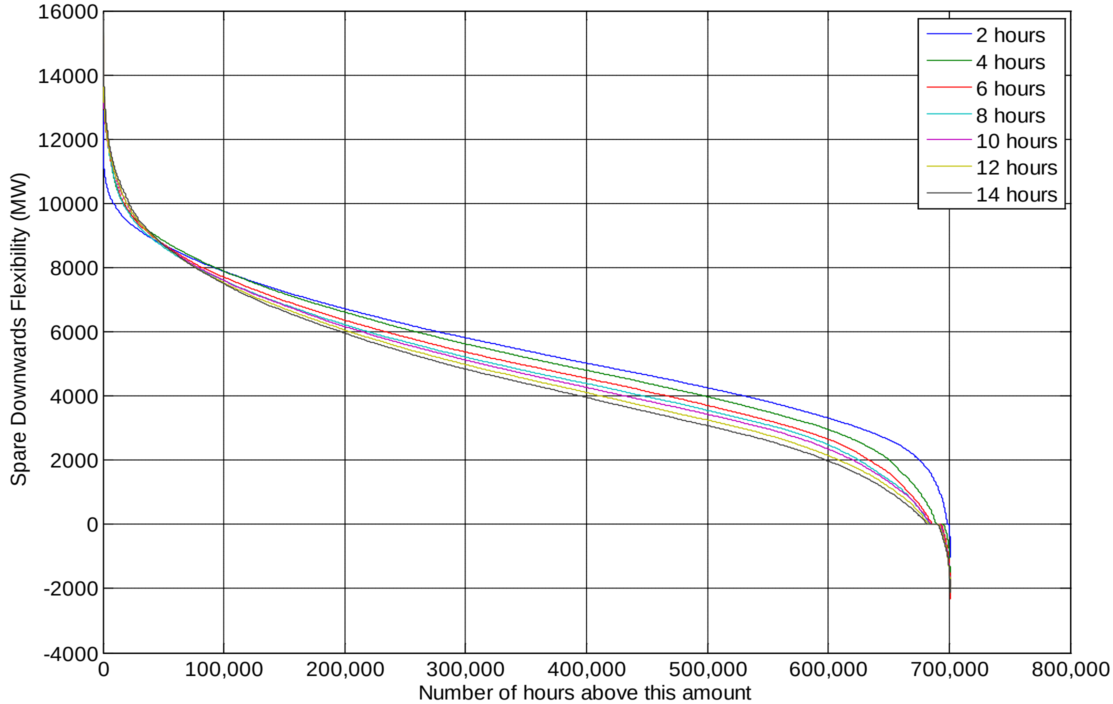

Figure 37: Duration Curves for Spare Downwards Flexibility when utilized hydro flexibility is subtracted from available hydro flexibility, for hydro generation over 80 years of hourly data

The remaining upwards flexibility from hydro can be seen to be less for 14 hour look ahead, as expected from earlier. Looking at values under 1000 MW, it can be seen that some of the look ahead horizons show values less than zero. The method would therefore show that, if intra-hour ramps are covered as they currently are using Aurora's assumptions, there may not be enough flexibility to manage intra and inter-hour ramps. It can be seen that there are approximately 83,376 hours when the available flexibility left for additional 14 hour up ramps after the system manages existing 14 hour ramps are less than 1000 MW (approx. 12% of the time). Approximately 47,000 hours (6.7%) there is zero or less remaining capability, while there are 22,500 hours (3.2%) when remaining flexibility is less than zero for 14 hour capability. These hours when little are available are examined in more detail later when spare hydro and thermal flexibility are combined.

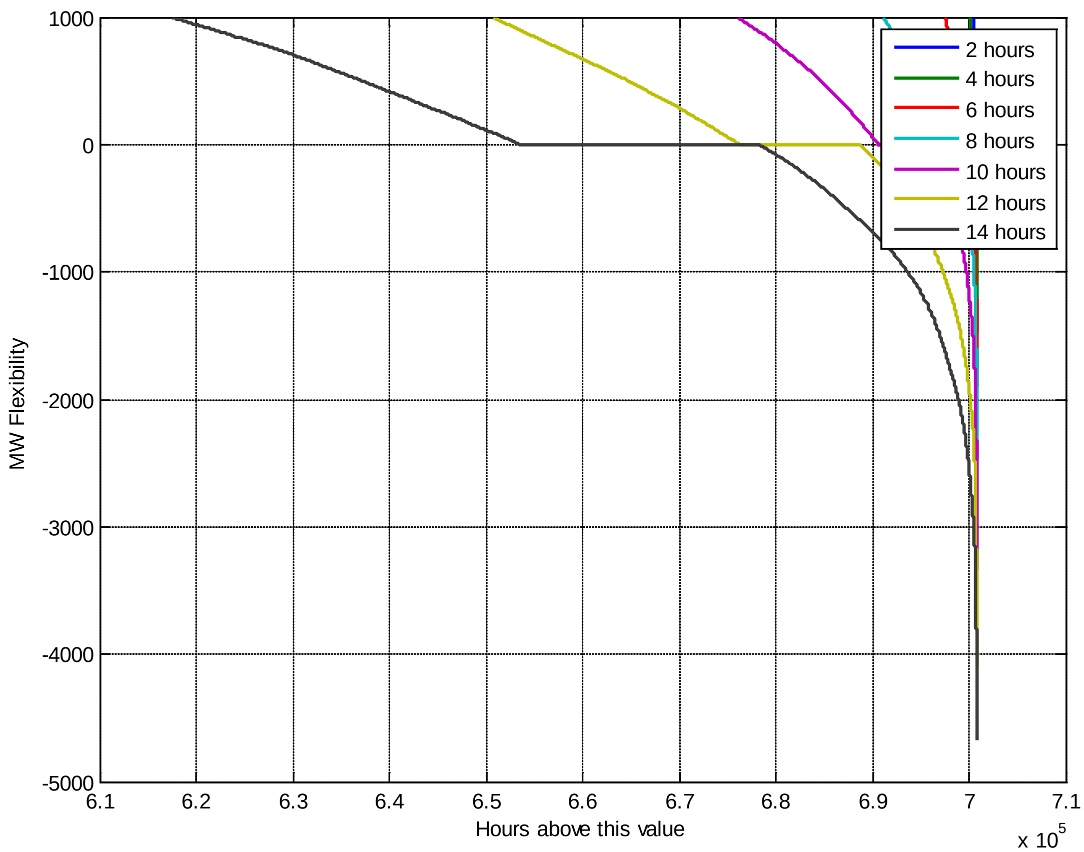

Figure 38: Spare hydro upwards flexibility capability for those periods less than 1000 MW available after accounting for flexibility used

Adding the thermal and hydro remaining flexibility together gives the following duration curves for upwards (first) and downwards ramping available after the requirements have been met. As with other figures, the system is more constrained when managing long ramps due to the nature of energy limited hydro and the fact it cannot be kept at a high level for as long a period of time. Looking at the bottom 1000 MW, it can be seen that there are still hours when there is very little flexibility available. However, there are less constrained periods when conventional and hydro are added together compared to hydro alone.

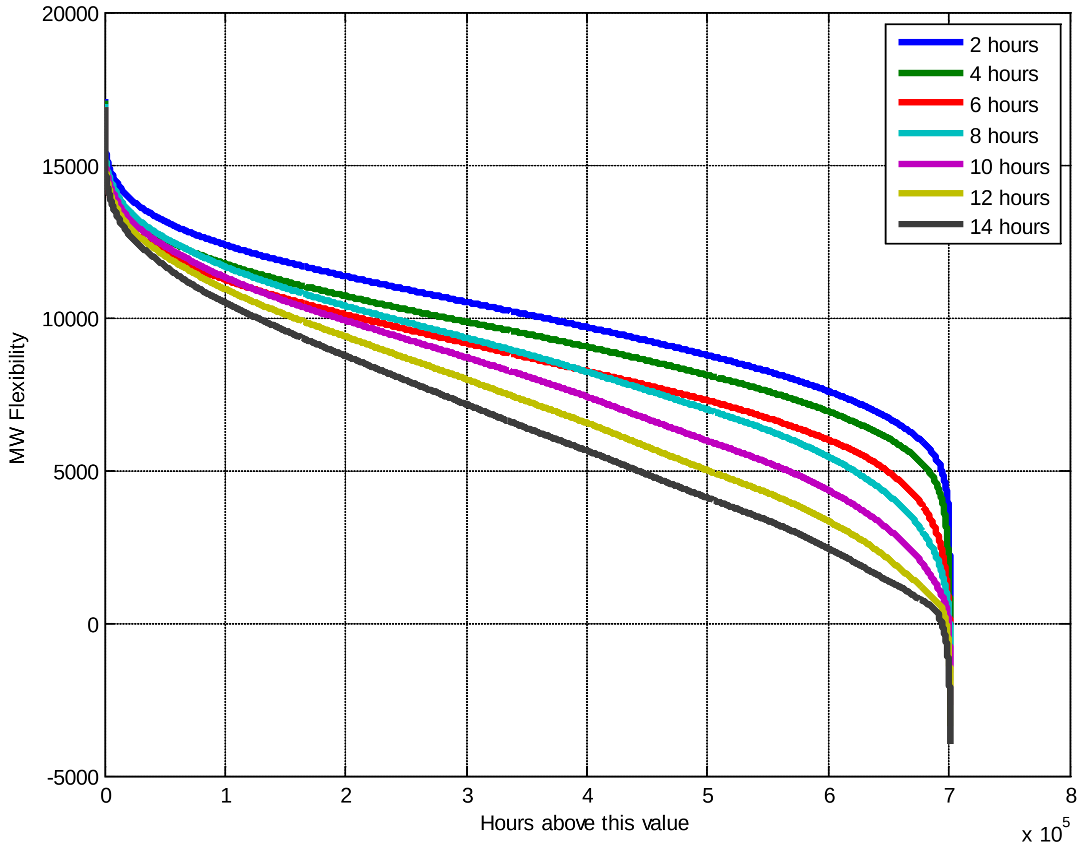

Figure 39: Duration Curves for Spare Upwards Flexibility when utilized hydro and thermal flexibility is subtracted from available hydro and thermal flexibility, based on 80 years of hourly data

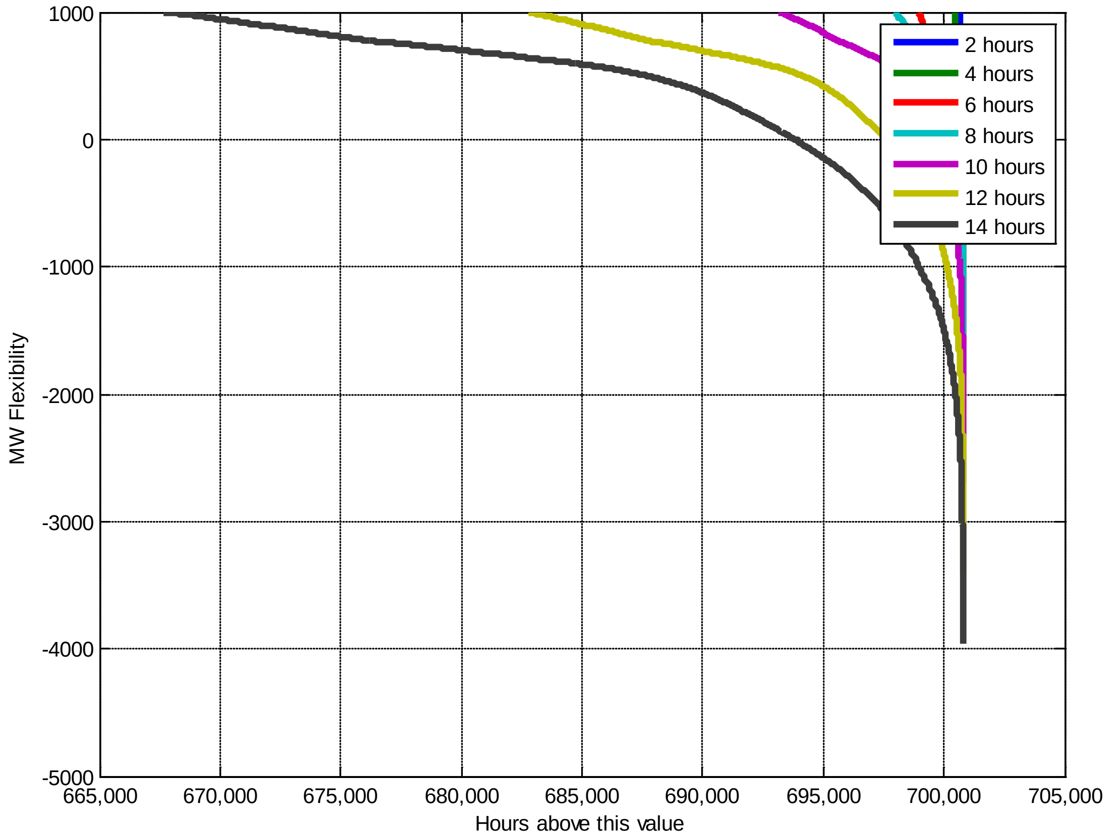

Figure 40: Unutilized upwards flexibility for different time horizons less than 1,000MW

There are approximately 33, 000 hours (4.7%) with less than 1000 MW spare flexibility in 14 hour periods. More details are given in the table below. The following table shows how frequently up ramping capabilities dip below certain amounts. As can be seen, for shorter horizons, there are virtually no periods when flexibility is constrained. However, longer term flexibility is more frequently constrained. The largest deficits are over 3 GW of flexible capacity short.

Table 2: Hours and percentage of time with low upwards flexibility available for different time horizons

	2 hour	4 hour	6 hour	8 hour	10 hour	12 hour	14 hour
<1000 MW	118	356	1,851	2,870	7,655	18,043	33,174
% of time	*.02%*	*0.05%*	*0.3%*	*0.4%*	*1.1%*	*2.6%*	*4.7%*
<500 MW	53	167	765	844	2,477	6,638	13,097
% of time	*~0%*	*0.03%*	*0.11%*	*0.12%*	*0.4%*	*1%*	*1.9%*
<0MW	1	49	190	292	1,081	3,202	6,957
% of time	*~0%*	*~0%*	*0.03%*	*0.04%*	*0.15%*	*0.5%*	*1%*

Looking at 2 hour ramping remaining flexibility by month using box plots, it can be seen that April-August are most constrained, with lower averages and 9th percentile values. Most of the time, there is over 5 GW of available spare flexibility, as the whiskers show the 9th percentile.

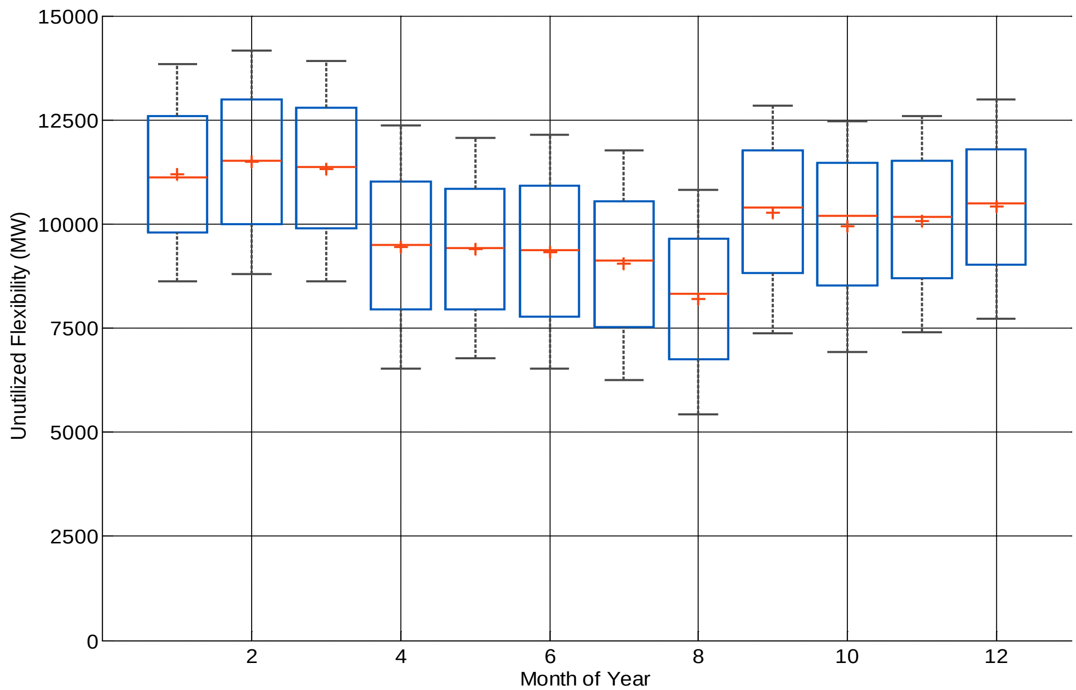

Figure 41: Box plots showing mean (line), median (cross), 25th/75th percentiles (box) and 9th/91st percentiles (whiskers) for unutilized 2 hour upwards ramping capability on a monthly basis

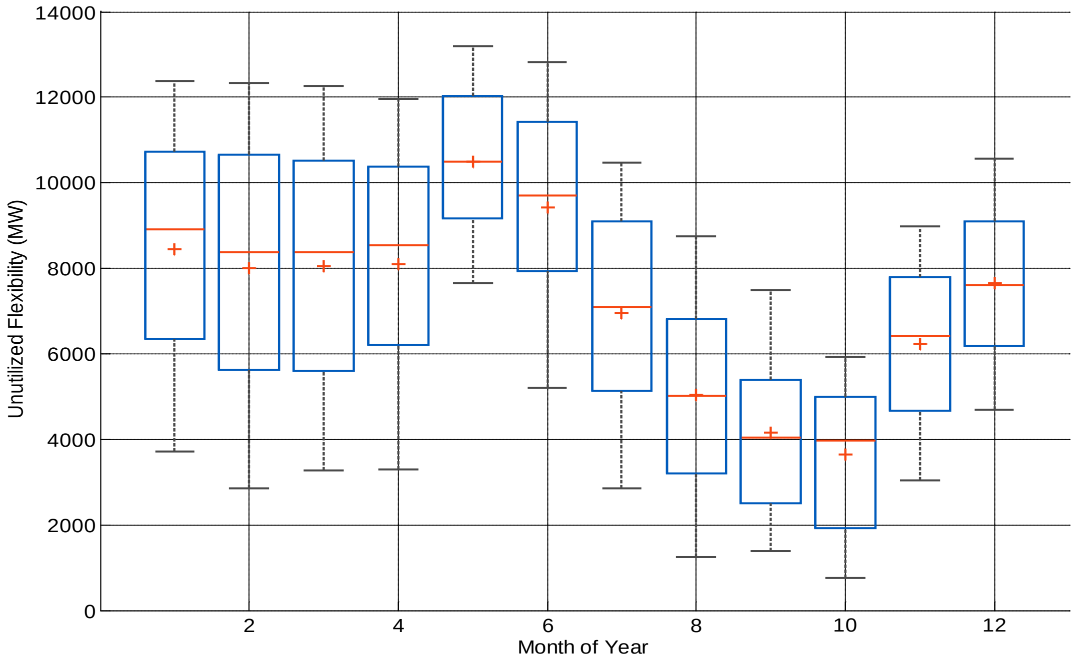

Figure 42: Box plots showing mean (line), median (cross), 25th/75th percentiles (box) and 9th/91st percentiles (whiskers) for unutilized 12 hour upwards ramping capability on a monthly basis

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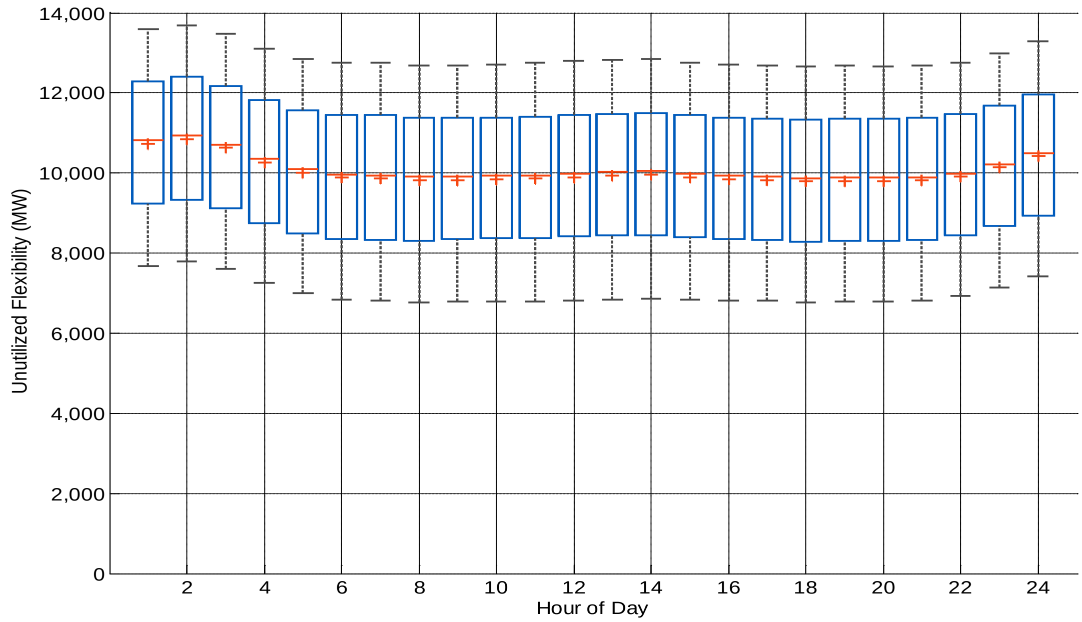

Figure 43: Box plots showing mean (line), median (cross), 25th/75th percentiles (box) and 9th/91st percentiles (whiskers) for unutilized 2 hour upwards ramping capability on an hourly basis

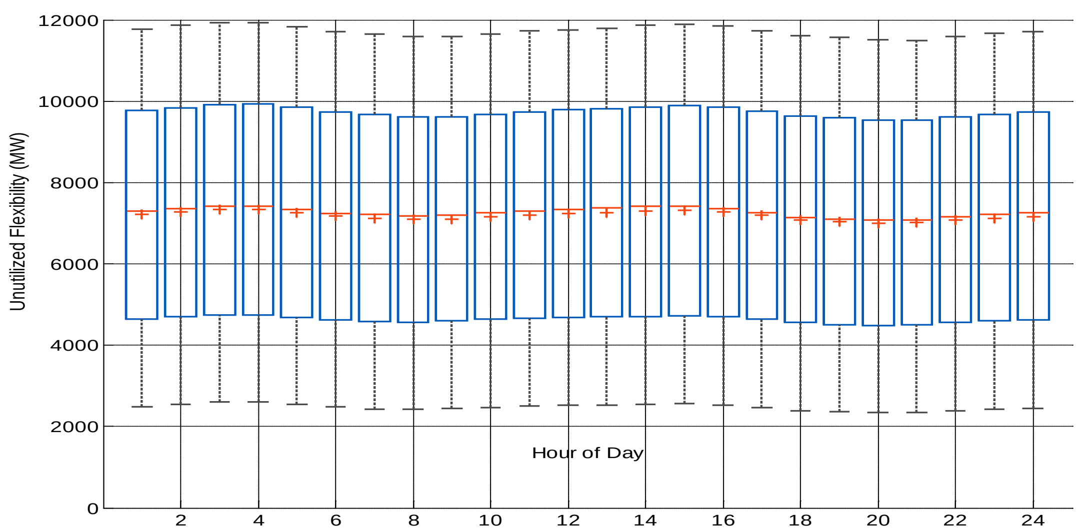

Figure 44: Box plots showing mean (line), median (cross), 25th/75th percentiles (box) and 9th/91st percentiles (whiskers) for unutilized 12 hour upwards ramping capability on an hourly basis

By hour of day, there is no obvious pattern for 2 hour flexibility being constrained, although they are slightly higher during the night, when 2 hour upwards flexibility would be less constrained. A similar lack of clear pattern can be seen for 12 hours. For down ramping, the following duration curve again shows the same amount of spare capacity across all time horizons in most cases. This is zoomed in to the periods when less than 1000 MW is spare in the following figure.

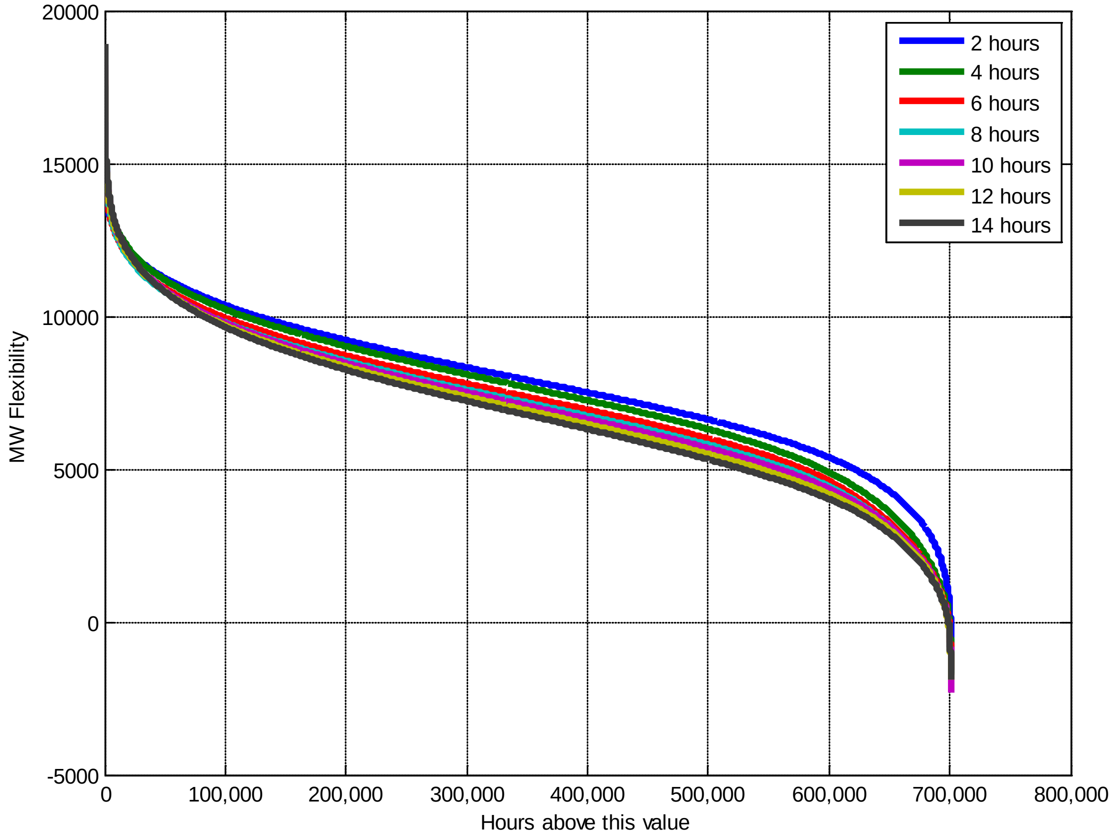

Figure 45: Duration Curves for Spare Downwards Flexibility when utilized hydro and thermal flexibility is subtracted from available hydro and thermal flexibility, based on 80 years of hourly data

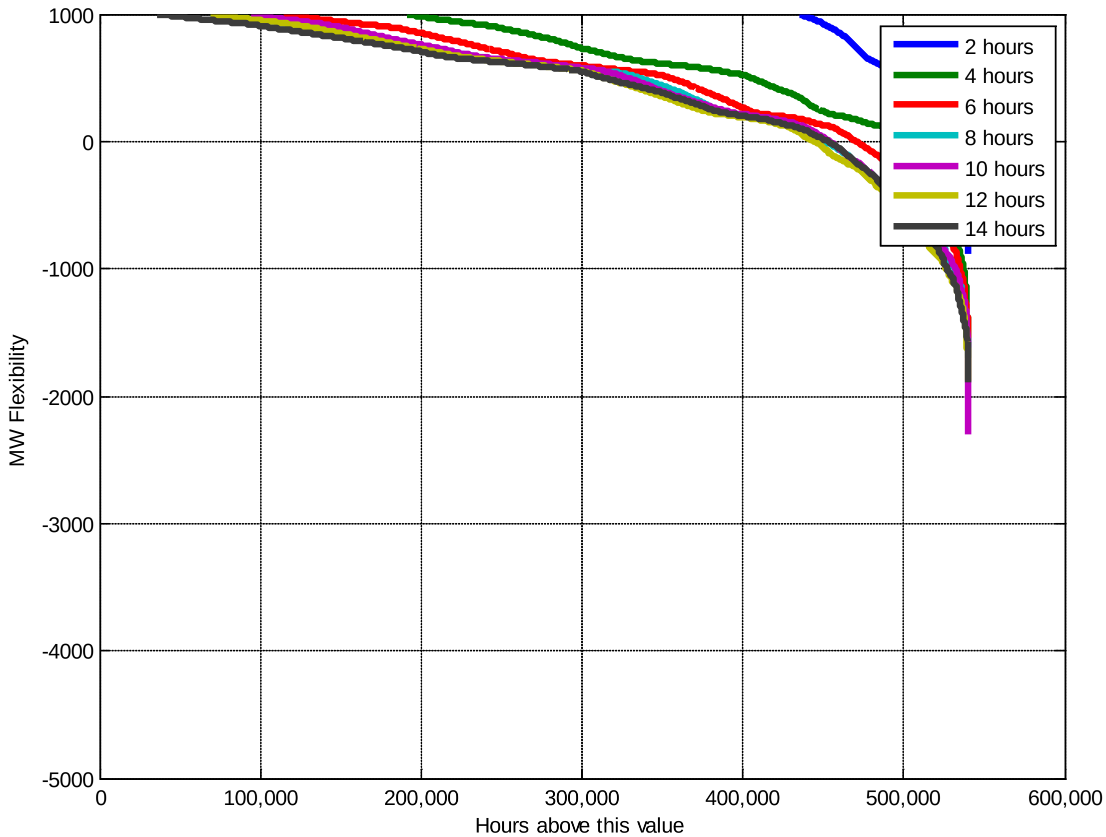

Figure 46: Figure 47: Unutilized upwards flexibility for different time horizons less than 1,000MW

Table 3: Number of hours and percentage of time with low downwards flexibility available for different time horizons

	2 hour	4 hour	6 hour	8 hour	10 hour	12 hour	14 hour
<1000 MW	2,098	6,978	8,505	9,416	8,922	9,424	10,077
% of time	*0.3%*	*1%*	*1.2%*	*1.3%*	*1.25%*	*1.3%*	*1.4%*
<500 MW	716	2,689	3,703	4,076	4,251	4,519	4,526
% of time	*0.1%*	*0.38%*	*0.53%*	*0.58%*	*0.61%*	*0.64%*	*0.65%*
<0MW	117	761	1,376	1,759	1,702	1,897	1,728
% of time	*~0%*	*0.11%*	*0.2%*	*0.25%*	*0.24%*	*0.27%*	*0.25%*

Comparing this table to upwards flexibility, a few items of note can be seen. First, the differences as the horizon decreases is not as pronounced, particularly for horizons from 4 hours and higher. While the longest horizons do not see negative or low values as frequently as the upwards direction, the shorter horizons are more likely to see low spare capacity or negative capacity.

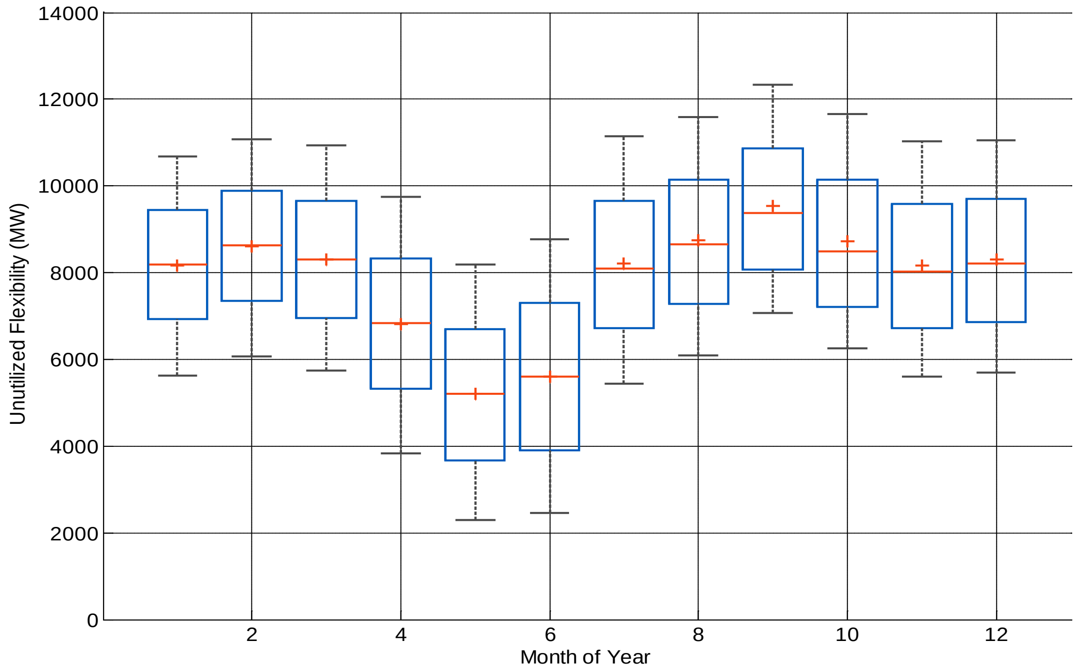

Figure 48: Box plots showing mean (line), median (cross), 25th/75th percentiles (box) and 9th/91st percentiles (whiskers) for unutilized 2 hour downwards ramping capability on a monthly basis

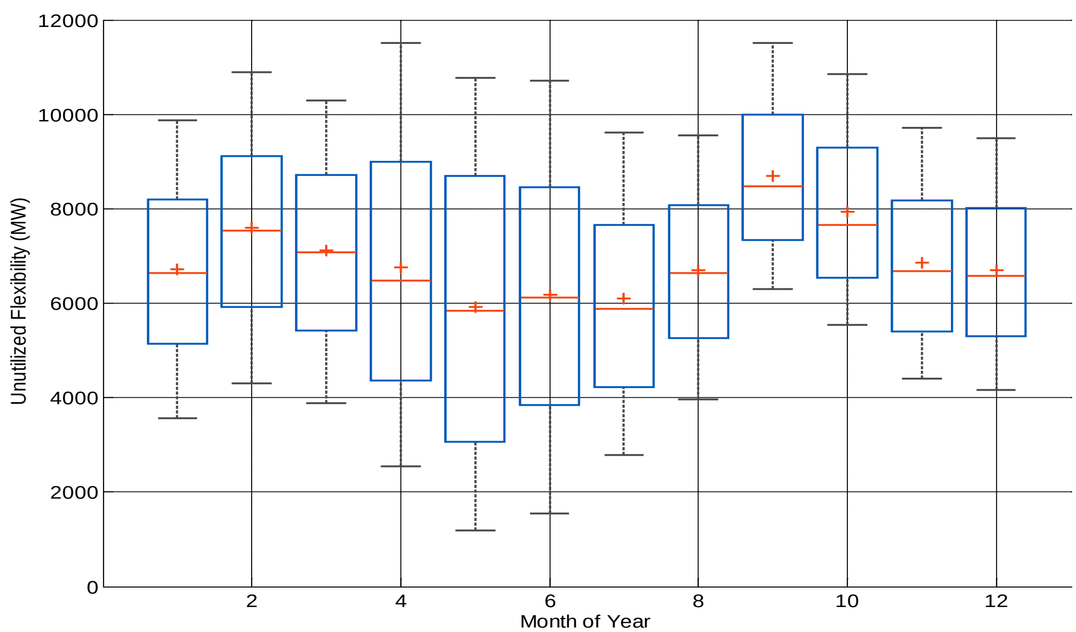

Figure 49: Box plots showing mean (line), median (cross), 25th/75th percentiles (box) and 9th/91st percentiles (whiskers) for unutilized 12 hour downwards ramping capability on a monthly basis

Looking at remaining downwards flexibility in a 10 hour horizon on an hourly basis, it can be seen that the least amount is at approx. 1000, which means that ramping over the period 10am to 8pm is when there may be the lowest amount of available downwards ramping.

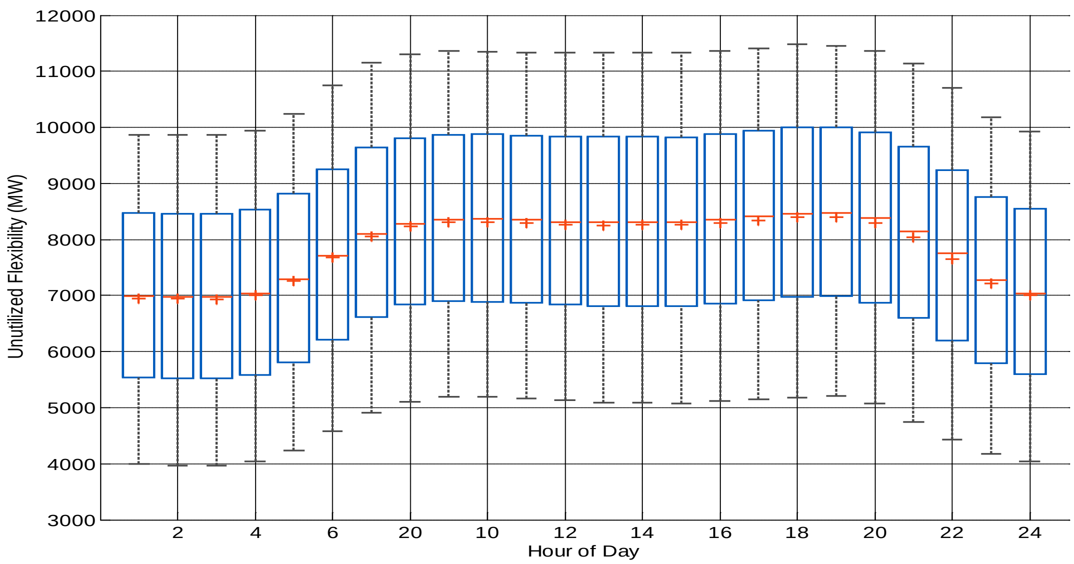

Figure 50: Box plots showing mean (line), median (cross), 25th/75th percentiles (box) and 9th/91st percentiles (whiskers) for unutilized 2 hour downwards ramping capability on an hourly basis

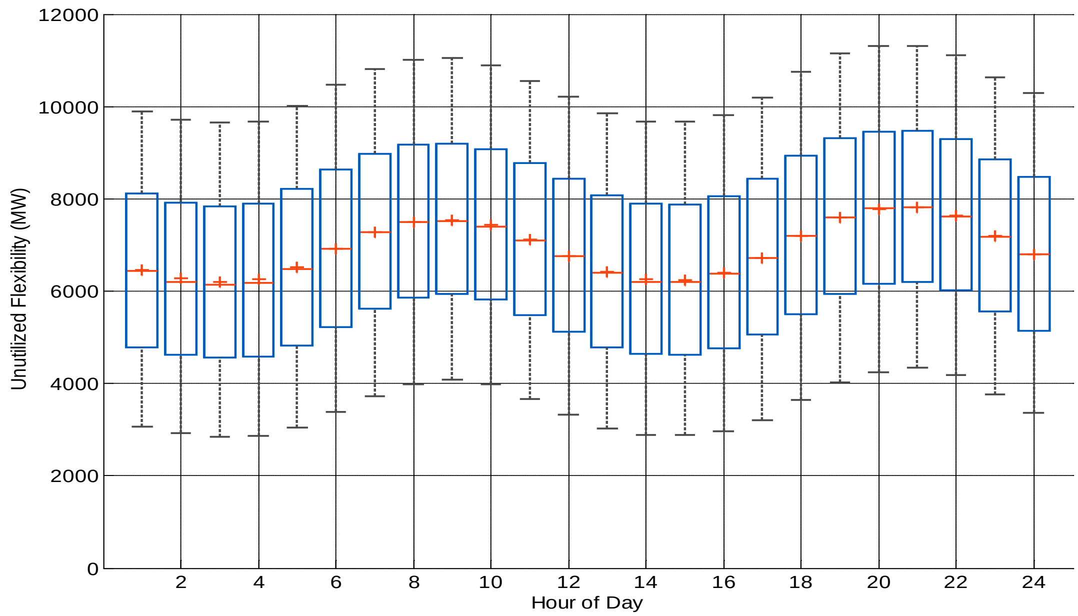

Figure 51: Box plots showing mean (line), median (cross), 25th/75th percentiles (box) and 9th/91st percentiles (whiskers) for unutilized 2 hour downwards ramping capability on an hourly basis

The final result is to look at the annual variations in the results for unutilized flexibility capacity. Note load and wind remain the same and only hydro changes from year to year; this may underestimate the range of variability and flexibility. As can be seen, there is significant unused flexibility variation depending on the year. For upwards, the mean amount of spare flexibility is between 8, 500 MW and 12, 500 MW, while outliers range between approx. 6000 MW-9000MW at their lowest. 1971 hydro year shows the lowest amount of available downwards flexibility, with many years showing similar amounts, and years such as 1994 showing a significant reduction in periods with low amounts of upwards flexibility.

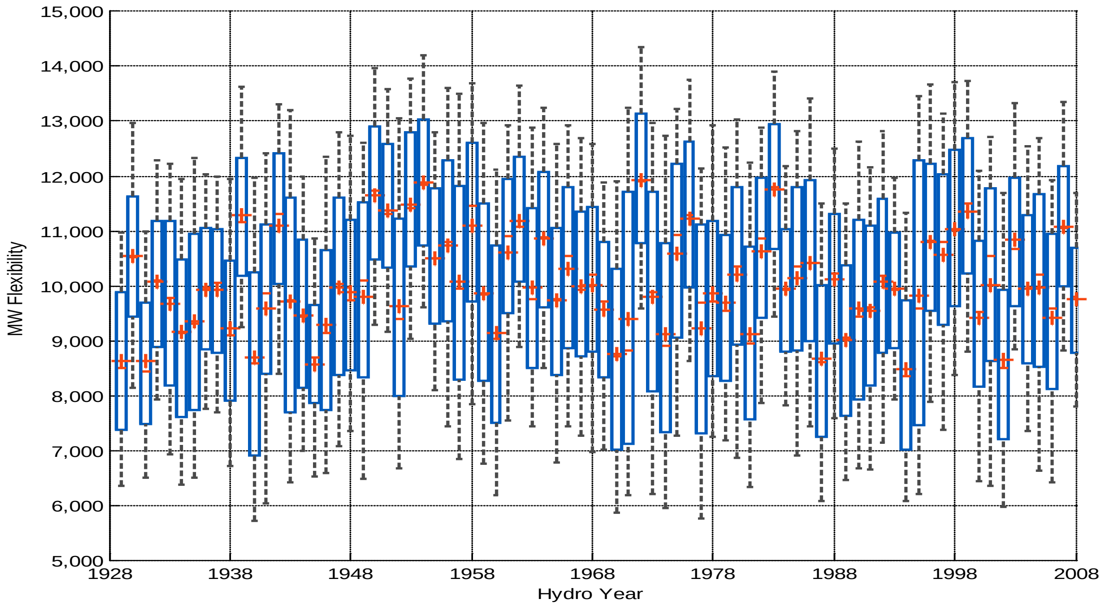

Figure 52: Box plots showing mean (line), median (cross), 25th/75th percentiles (box) and 9th/91st percentiles (whiskers) for unutilized upwards flexibility when considering both hydro and thermal generation by hydro year

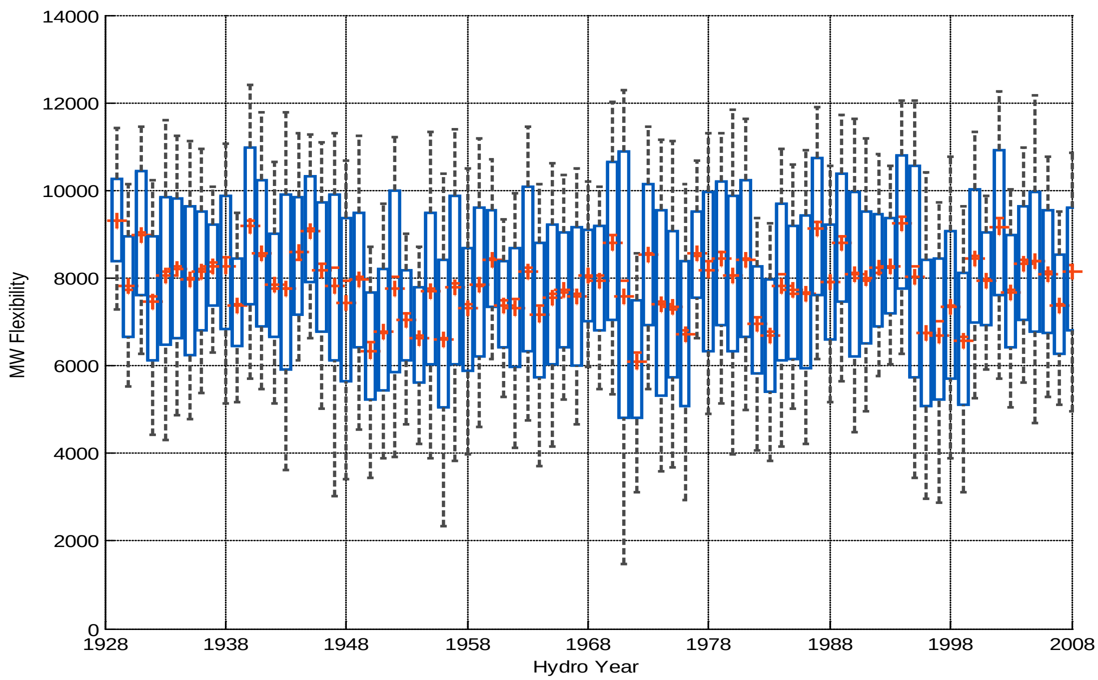

Figure 53: Box plots showing mean (line), median (cross), 25th/75th percentiles (box) and 9th/91st percentiles (whiskers) for unutilized downwards flexibility when considering both hydro and thermal generation by hydro year