INTEGRATION COST OF DEMAND RESPONSE

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1. Abstract

There has been growing interest in demand response in recent years due to the increasing levels of variable generation on power systems. However, little attention has been given to the interrelationship between the two, despite the fact that they could complement each other. In order to fully understand the potential of demand response, it is necessary to evaluate it. This paper reviews the literature and proposes that an integration study approach, which has historically been used to assess the costs and impacts of placing renewable generation on a power system, could be a suitable means to determine the value of demand response. The challenges associated with extending these existing methodologies to include demand response are presented and discussed. It is highlighted in this paper that it is necessary to carefully consider the key characteristics of the demand response resource in an integration study and that a holistic, system approach is vital. The issues associated with establishing demand response baselines and with data availability are also explored.

2. Introduction

There has been considerable research and development in the area of demand side management (DSM) and demand response (DR) in recent years. Studies have shown that using DR to facilitate the integration of renewable generation is technically feasible (Strbac 2008; Milligan & Kirby 2010) and this has attracted much interest around the world. Much of the work in this area has focused on demand side energy efficiency, as well as peak shaving and load shifting (Dietrich et al. 2012), while there has been less work in utilizing DR for the provision of ancillary services. This is due to, perhaps, the fact that historically DR programs have focused on reducing consumption and shaving demand peaks, with much less attention given to ‘immediate reliability response’ (Kirby 2007). It is now believed that DR is in a prime position to provide reliability services to the power system (Kirby 2007; Ma et al. 2013). While, there exists a well-established body of research that examines variable generation integration issues as well as the potential of DR, the interrelationship between the two has largely been neglected (Cappers et al. 2011). However, some studies (for example Sioshansi 2010, Madaeni & Sioshansi, 2012) have considered the interaction between them and have shown that there may be a benefit in implementing DR measures in conjunction with renewable generation, in terms of social welfare gains and in terms of carbon emission abatement.

Kim & Shcherbakova (2011) suggest that DR can be successful in reducing short run uncertainty in electricity supply when combined with investment incentives. This suggests that DR is but one of a number of resources which could be used in a portfolio to maintain the supply demand balance with increasing penetrations of renewable generation and to reduce uncertainty of supply and thus a full understanding of the interaction between DR, renewable resources and the existing power system will be crucial for determining implications for both system operation and for market design. The concept of energy systems integration (ESI) is also emerging as a very important research area and highlights that there are advantages to be gained from the interaction and interdependencies between the different energy systems and data networks (Kroposki et al. 2012), further stressing the importance of assessing the effects of interaction between resources.

Milligan et al. (2011) suggest that demand response is likely to be developed in the coming years but they include the caveat that this is dependent upon whether the ‘flexibility it offers is valuable and properly valued’. It is clearly necessary to determine its value both as a stand-alone resource and in combination with renewable generation and other reliability and ancillary services resources. Despite the considerable interest in DR, according to Nguyen et al. (2012) there has been very little attention given to the development of a ‘comprehensive framework for estimating DR benefits across all players’ and they suggest that without such a framework it may not be fully possible to determine the value of DR. Applying the concept of an integration cost (or benefit) to the analysis of the inclusion of DR on the power system could provide a means to ascertain its true electricity market value and knowledge of the value could provide an indication as to which markets (energy, capacity or ancillary services markets) are most suited to demand side participation, a view which is also expressed by Macdonald et al. (2012). It is suggested by Ma et al. (2013) that it is indeed possible to adopt methodologies historically used to study grid integration of variable generation to study DR.

There is considerable merit in adopting an integration cost approach as renewable integration studies are well documented in the literature and considerable experience and understanding has been gained. Furthermore, renewable integration studies represent a significant set of methodologies to quantify the impacts of increasing
penetrations of renewables on electricity systems and are important in the wider context of ESI. However, there are a number of issues and areas of contention associated with integration study methodologies in general. The fact that the results are heavily dependent on the underlying assumptions upon which integration studies are predicated and the difficulty in establishing the conditions under which to compare the ‘with’ and ‘without’ cases (Milligan et al. 2011) have been identified as issues. Thus, any comparison between studies is rather involved, as it is necessary to understand the assumptions in order to interpret the results. Perhaps more profound than simply being ‘involved’ or challenging is the fact that it may not even be possible to calculate integration costs and it is at least very difficult to accurately ascertain these costs because of the large number of assumptions upon which the results are based. This is a fundamental problem and leads Milligan et al. (2011) to suggest that, to date, calculations of integration costs have not been performed “in a completely satisfactory manner”.

Without a robust integration study methodology underlying an assessment of DR, it will be difficult to answer some important research questions. For example: What is the ultimate cost and benefit of DR? What is the true market value of DR and what would the market value need to be in order to make DR economically and commercially viable? Indeed, it is suggested by Nguyen et al. (2012) that without a robust method to estimate the value of DR it is almost impossible to justify the reliability improvement attributable to DR. The implications of this could be considerable and stem from the fact that if DR is under evaluated, investment in DR will be limited, leaving a substantial and beneficial resource largely untapped, necessitating the procurement of vital system services from other, potentially more expensive, more carbon intensive, system assets. There is evidence that DR could provide some system services more effectively and more reliably than conventional generation (Kirby 2007). Thus, if DR proves to be the neat and sophisticated solution it is claimed to be, failure to exploit the resource is clearly not optimal. On the other hand, if the potential of DR is over estimated, considerable amounts of money could be invested in order to exploit a service which ultimately cannot be realized or can only be realized at certain times of the day or year.

The main aim of this paper is to collate some of the issues regarding integration studies raised in the literature and to highlight a number of the important areas of future work which will be necessary in order to accurately determine the value of demand response. Section 3 discusses some of the key characteristics of demand response which are deemed necessary for inclusion in an integration study approach. Section 4 introduces the concept of an integration cost as well as generic integration study methodologies and associated flaws, while the issues associated with extending such integration study methodologies to include demand response are also explored, drawing upon the lessons learned from previous integration studies and also discusses some of the issues surrounding obtaining data for modeling the demand response and on establishing baselines for particular types of DR programs. Final comments and conclusions are presented in Section 5 and 6.

It should be noted that while the focus in this paper is placed mainly on a discussion of costs and integration costs, it is understood that there are many benefits associated with the implementation of DR and thus ‘cost’ is used throughout in its broadest sense as a means to illustrate some of the challenges and issues associated with an integration study approach to DR. Ultimately, the aim of the author is to ascertain the value of DR and in order to do so, and in order to build upon existing integration studies, it is important that an understanding of the integration cost of DR is obtained.

3. Demand Response: Key Characteristics

In order to ascertain the system level value of DR it is necessary to accurately model the different DR resources appropriately. The first step in this process is to understand the key characteristics of the DR resource, much the same way a wind integration study involves an assessment of the wind resource.

Demand response (DR) is often described as the changes in electrical energy usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time or to incentive payments (Li, 2010) or to signals from the system operator. It is widely acknowledged that this is not a new concept; historically, demand shedding was used for emergency contingency response, but there has been much interest in recent times in more continuous demand response due to the increasing penetration of renewable generation, the potential of DR to assist in integrating variable generation (Milligan & Kirby 2010), the fact that it could be a more cost-effective means to meet occasional peaks in electricity than peaking plants (Earle et al. 2009) and could potentially reduce system costs (Dietrich et al., 2012). According to Milligan et al. (2012), the Western Wind and Solar Integration Study has shown that increasing the levels of demand response would be a cheaper option than increasing generation capacity to meet contingency reserve requirements. Numerous studies have shown that using DR to facilitate renewables is technically feasible through reserve provision or through
generation margin reduction (Strbac, 2008), while it has been shown that in some cases that demand can provide responses which are greater than the responses garnered from generators (Kirby 2007; Ma et al. 2013).

It should be noted that the increase in renewable generation is not necessarily a driver for the investigation and research in the area of DR. The significant and rapid development of telecommunications, control systems and computation has pushed DR to the fore, to such an extent that DR is now being seriously considered as a power system asset and this would have been the case irrespective of the increase in renewable penetration. It is merely a beneficial coincidence that DR and renewable generation are complementary, and this is receiving much attention, both in the literature and from utilities.

Cappers et al. (2011) examine how demand side resources could be used to integrate wind and solar resources in the bulk power system, identify barriers that currently limit the use of demand side strategies and suggest several factors that should be considered in assessing alternative strategies that can be employed to facilitate wind and solar resources in the bulk power system. Chuang (2007) notes that despite the fact that some system operators have established DR programs, while many more are interested in establishing such schemes, the many ways in which to implement a program and the inconsistencies associated with the terminology pose considerable challenges. There are numerous ways in which to classify DR programs, for example, in terms of application or in terms of signaling mechanisms; According to EnerNOC (2009), it is common to classify DR programs based on their incentive structure, while Goldman et al. (2010) suggest that DR events may be activated by economics or by reliability requirements. Additionally, programs can be classified according to the method of actuating a response from the demand side (Chuang, 2007). Alternatively, Nguyen et al. (2012) identify three categories of DR whereby the DR scheme is classified according to the organization who oversees the scheduling of the resource; transmission system operator-based, distribution system operator-based or retailer based. Within each classification there are many different DR programs and there is often considerable overlap. This can be a source of confusion when drawing comparisons between different programs and different systems and is also something that needs to be considered during the modeling phase of an integration study. There is also the temporal aspect of DR programs; some programs are designed to operate within hours, minutes or even seconds of a signal or a disturbance. The ability of a load to respond will depend highly on the type of load and on its physical characteristics and it is crucial that these characteristics are appropriately represented in DR models.

There is also the challenge associated with the fact that the manner in which reserves and ancillary services are classified vary across systems. While not an issue that will be explored directly in this paper, DR has the potential to take part in ancillary services markets and thus there is a chance that the terminology could prove to be a barrier to widespread implementation of DR. This barrier stems from the fact that the definitions of ancillary services have been built up heuristically and traditionally conventional thermal plants were the sole providers of these services. Such definitions, when ‘hard-wired’ into the market design, may preclude DR programs from participating. Other barriers including the lack of consumer knowledge, the various degrees of consumer involvement and barriers regarding DR policies cannot be explicitly modeled in an integration study but should definitely be considered in the analysis of the results.

One potential DR program involves exposing end-use consumers to real time pricing, a concept which has long been understood as being more economically efficient in the short-run than offering customers a flat tariff (Boisvert & Neenan 2003; Allcott 2012). Although initially proposed many years ago, real time pricing (or spot pricing) has been brought to the fore in light of the renewed interest in demand side measures. For a more detailed discussion and comparison on the welfare impacts of flat tariffs and different off-peak and peak prices, the reader is directed to Boisvert & Neenan (2003) and to Schewe (1988). Real time pricing is just one of many proposed means for administering DR programs. For a more in-depth discussion of other DR programs, the reader is directed to Albadi & El-Saadany (2007) and to a workshop report drafted by the US Department of Energy (Kirby et al. 2011).

The prospect of introducing real-time prices opens up an avenue for triggering a response from the demand side and so is pertinent to the discussion here. Allcott (2012) estimates that increasing the number of electricity consumers who are exposed to real time pricing in the PJM1 market from 10% to 20% could increase welfare by $120 million per annum. Similarly, Boisvert & Neenan (2003) contend that failing to expose some retail customers to dynamic or real time prices, and therefore failing to encourage them to alter their demand in response, causes the significant deadweight social welfare losses to continue. It is shown that placing some customers on programs which incentivizes them to reduce demand in turn reduces the welfare losses. These market intricacies

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1 PJM is a Regional Transmission Operator which operates in the Eastern Interconnection of the United States.
and consumer behavior play a significant role in the final value of DR and thus need to be incorporated into models of the power system and the electricity market.

One of the main issues pertaining to DR is whether or not the associated benefits of incorporating DR into wholesale power system markets is justified (Boisvert & Neenan, 2003). The authors contend that this issue stems from the broader question as to whether electricity is a public or private good. They suggest that if electricity is a public good and therefore non excludable, perhaps DR should be accommodated in wholesale and retail markets through the use of incentives. On the other hand, the expansion of DR programs should be left up to individual consumers based on their personal estimation of the competitiveness of DR if electricity is deemed to be a private good. Essentially, this distills down to a question of whether the development of DR should be subsidised and regulated or if it should be left to market mechanisms. This is a very interesting question and warrants further analysis, but this will not be considered further here. However, it is likely that it will be necessary to consider the market structure that will be in place in future scenarios with significant DR penetrations.

Cappers & Ellis (2009) suggest the value of DR is primarily a result of avoided capacity costs and it is stated that it will be necessary to select carefully in which periods to operate DR. Furthermore, the work by Macdonald et al. (2012) found that in the California ISO South region, for the years 2009 to 2011, winter months have large evening peaks in regulation up prices while the early morning hours have much less value, a change in value of $10/MWh between the morning and the evening. Similarly in the west reserve zone of New York ISO, for all seasons, the spinning reserve prices in the early morning hours are close to zero (Macdonald et al., 2012). This work highlights the importance of including this temporal variation in market clearing prices (MCPs) when assessing the value of DR participation in ancillary service markets. This would suggest that there are limited time periods over which to earn revenue through participation in an ancillary services market, which may reduce the overall value of DR for the participant. There is also evidence that large scale integration of wind energy can cause market prices to fall (Milligan & Kirby 2009) due to its near zero marginal cost. There is a high probability that DR, which is likely to have no opportunity cost, will also lower market prices. Crucially, the authors in Macdonald et al. (2012) highlight that, despite the small size of ancillary service markets, because of the co-optimization of energy and ancillary service markets, ancillary service markets should be robust to changes in a portion of their resources. However, there may be a point at which the penetration of low-cost resources will cause the marginal clearing price to fall to zero (Macdonald et al., 2012). The work by Ma et al. (2013) also shows that a suppression of ancillary service market prices is indeed a realistic possibility due to the fact that DR resources bid at zero cost. This could also have serious implications for DR revenue streams and thus the value of the resource to the participating customer. Evidently, this highlights that it is imperative to adequately model energy and ancillary services markets in simulations aiming to ascertain the value or cost-benefit of demand response.

Interestingly, Boisvert & Neenan (2003) raise the issue that savings on customers’ electricity bills may not be sufficient enough to warrant investment in equipment and to compensate for the inconvenience of following electricity prices on a continuous basis, when they may only be required to react on rare occasions. Of course, this will be dependent upon the type of program being implemented and the degree of customer participation required. Additionally, and perhaps more fundamentally, since electricity is a good, the ability of DR and DSM to participate in energy and ancillary service markets will necessarily be limited (Kirschen & Strbac 2004). This is because the length of time the resource can be provided is limited and the frequency of resource deployment is also limited as, ultimately any program will be disruptive to the consumer and thus utilities will be reluctant to deploy the program regularly (Cutter et al 2012). This is an important point to consider when modeling DR resources and is also connected to the physical characteristics and nature of electricity loads.

Some of the physical characteristics of a DR unit that make it unique in comparison to a thermal generator include the fact that it is energy limited. The energy limited nature of DR is often viewed as being similar to conventional storage units and thus in many places in the literature, load shifting units are modeled and considered as such, for example by Keane et al. (2011) and Andersen et al. (2006). There are also constraints regarding response times and the speed at which a DR unit can decrease or increases its power consumption, in much the same way there are constraints on conventional thermal generating units. It is crucial that these constraints are modeled appropriately in order to accurately reflect the physical characteristics of the DR unit and in order to attain realistic results. It should also be noted that after a DR unit has provided a service to the system, the energy which the unit relinquishes will need to be recovered at a later stage. If the recovery periods are uncontrolled, a number of units’ recovery periods may coincide and this may inadvertently create an additional, unintentional peak in the system demand.
It is also suggested by De Jonghe et al. (2012) that the interaction between energy efficiency measures and DR should be modeled. Any efficiency improvement on the demand side will unavoidably reduce the demand level and thus the amount of demand which is capable of responding to a demand response event. However, although energy efficiency measures could reduce the potential capacity of demand response, they could actually improve the adequacy and characteristics of the response. For example, the addition of greater amounts of insulation in a building will reduce the net heating load, but will also increase the thermal energy store of the building, thereby increasing the length of time a demand can provide a response for. The effects of building energy efficiency should be fully considered in the resource assessment stage of an integration study involving DR.

All of these aspects and characteristics would need to be incorporated into models of the DR resource in order to represent it accurately. Of course, the level of detail and the characteristics that will be included will depend upon what in particular is being investigated, but it is crucial to be aware of all of the aspects of DR when analyzing and interpreting results.

4. Integration Costs and Integration Studies

Power systems continue to evolve and considerable investment in the sector is anticipated in the coming years. The addition of new generating technology, conventional and renewable, has an impact on the power system in terms of the capital investment requirement for grid reinforcement and the change to the operation of the power system and the associated operating costs. The costs associated with these impacts on system operation and investment are often expressed as integration costs (Meibom et al. 2009).

There is a considerable amount of literature dealing with the issues surrounding integration costs and integration study methodologies due, in part, to the widespread adoption of renewable energy and the associated integration studies. In Soder (2005), the effects of different integration cost calculation methodologies on the results are discussed, while the work in Milligan et al. (2011) examines the evolution of wind and solar integration studies, focusing on the techniques which work, common errors and the general difficulty in ‘integration cost’ calculations. It should be stressed that the main difficulties in integration studies lie not solely in the power system modeling, though considerable issues do exist, but in establishing the conditions under which to compare the ‘with’ and ‘without’ cases (Milligan et al. 2011). De Jonghe et al. (2012) raise the point that while there has been significant work and advances in this area in recent times traditional power system models have neglected to incorporate DR and there is a need now for these models to be enhanced in order to better account for the unique characteristics of the demand side which were introduced in Section 3 and to determine the potential costs and benefits, and eventually the value, of DR.

According to Cappers et al. (2011), there exists a well-established body of research that examines variable generation integration issues as well as the potential for DR, however, the interrelationship between the two has been largely neglected. Any methodology employed to evaluate the costs associated with demand response would need to be fully aware of this. Realistic modeling of demand side resources and aggregation will be critical. One of the main issues at this stage is how demand response should be modeled. More specifically, how should DR resources be modeled in integration studies? A review of the literature suggests that modeling of demand response is possible but often based on a number of assumptions regarding baselines, price elasticities and penetration levels. There are numerous variations of demand side response programs with potential at this stage. Understandably, all of the different types of programs cannot be incorporated into an integration cost study for computational reasons. Thus, the question is which programs have the most potential and therefore which programs should be assessed in an integration study? Most renewable integration studies begin with a detailed resource assessment and as is stated by Kowli & Meyn (2011), an understanding of the characteristics of resources is required for robust and reliable integration into the power system. A similar assessment of the demand side potential is a necessity if demand side participation is to be modeled in integration studies and if the value and potential of the DR resource is to be ascertained without over or under estimation. Preliminary work on demand response resource assessment could inform the decision regarding which programs to focus on, allowing an initial appreciation of the most fruitful resources to target. Iterations are possibly beneficial here, in that one DR program could be assessed using an integration study and its costs and its impacts, both positive and negative, analyzed. This analysis could then be used to update understanding of which programs merit further investigation in subsequent iterations of the integration study.

Before delving into a discussion relating directly to integration studies which include demand response, the issues pertaining to the concept of an integration cost and to existing integration study methodologies are first introduced.
4.1 Integration Cost Calculations and Integration Study Methodologies

One of the most common ways to measure system level impacts of integrating a new technology is as a cost. The total ‘integration cost’ has a number of different, but related, components: Operational costs include such things as fuel costs, start-up costs, maintenance costs and the cost associated with emissions permits (Meibom et al. 2009), while investment costs are often related to grid reinforcements and construction of plants. The term integration cost is widely used in the literature, particularly in reference to integration studies, and has been defined in a number of different ways. For example, integration costs can be defined as the additional system costs imposed by the inclusion of a new generating technology that are needed to meet system requirements at an acceptable level of reliability (Soder 2005, Holttinen et al. 2012). Similarly, the integration cost of wind power can be defined as the extra investment and operational cost of the non-wind part of the power system when wind power is integrated (Holttinen et al. 2009). While much of the literature deals with the integration costs of wind power, it must be stressed that integration costs are not restricted to wind power, nor do they relate solely to variable renewable generation; any new power plant has an associated integration cost. Thus, there could be an integration cost associated with DR and determination of this could help to estimate its value.

While it would be beneficial to have a succinct value to place on the cost of integrating a particular technology, it has been noted in the literature (Milligan et al. 2011; Milligan et al. 2012) that this is surprisingly difficult. It is possible to compare the costs associated with two different generating portfolios or scenarios, but ‘calculating an integration cost that only includes the added cost the power system incurs’ as a result of renewables (or the addition of another technology) is much more complex (Milligan et al. 2011) for reasons that will be discussed.

An important point to note when discussing integration studies is that the very definition of integration cost varies depending on the aim of the study. For example, if the goal of a study is to determine the effects of the introduction of a certain amount of wind generation on the system, it is likely that investments will be required to upgrade the transmission system and thus the resulting ‘integration cost’ will consist of investment costs and operational costs (Soder, 2005). On the other hand, if the study aims to assess how much wind can be integrated into the system as it stands without further transmission investments, the ‘integration cost’ will only consist of operational costs (Soder, 2005). For example, one study may aim to assess the implications of 5 GW of wind on a power system as it currently exists, without investments in transmission capacity, while another study could focus on determining the impact of 5 GW of wind accounting for any necessary investments in transmission. While these two studies both examine the effects of 5 GW of wind, both have adopted different approaches and one study will include investments as part of the integration cost, while the other will not.

Consequently, despite the vast number of integration studies, both completed and on-going (GE Energy 2010; Corbus et al. 2009), it is difficult to compare the results (Holttinen et al. 2008; Holttinen et al. 2006) and any comparison between studies is rather involved, as it is necessary to distil the ultimate aim of the study and the definition of ‘integration cost’ in order to interpret the results.

The methodology employed during an integration study is usually determined by the aim of the study and it is also found that the results of integration studies are highly dependent upon the study inputs (Soder, 2005). Furthermore, the terminology relating to system operation and market structures can also vary considerably from system to system. Some of the common approaches for assessing integration impacts include:

1. Simply increasing/adding the amount of new power. This leads to a decreased risk of capacity shortage as the amount of generation is increased and there is a consequential likely reduction in operating cost (Soder, 2005). The authors in Holttinen et al. (2012) recommend that this approach be employed when dealing with small levels of wind power penetration. They also suggest that with small levels of wind, existing operating procedures and market design should be used as a first pass, with amendments as necessary in later iterations. It would be interesting to determine if this approach is also suitable for small penetrations of DR.

2. Replacing existing capacity with the new power resource. According to Soder (2005), for this approach to work, it is necessary to establish the ‘alternative’ to the new power, which can be a contentious issue. The authors in Holttinen et al. (2012) suggest the use of this approach when dealing with greater penetrations of wind power. They also stipulate that flexibility needs and network configuration should be accounted for. It is further recommend in Holttinen et al. (2012) that considering higher penetrations of wind power should entail a close look at operating procedures and market design. Adopting this approach for the inclusion of large penetrations of DR could present a number of issues regarding what resource is considered to be the alternative to DR. Cutter et al. (2012) discusses how DR compares and
competes with combustion turbines and suggest that combustion turbines serve as a proxy for a flexible resource. Perhaps, combustion turbines would prove to be a suitable ‘alternative’ to DR in the base case.

3. Estimating how an economically efficient system should be configured to include a certain amount of new power (Soder, 2005). This could involve restructuring the transmission system, altering generators’ governor droop characteristics etc. This could be a suitable approach for incorporating DR in an integration study as DR could entail a market design or a new market and since DR brings the consumer into greater contact with the electricity system and thus the social welfare of the consumer is now becoming a topic of considerable interest.

In order to ascertain an integration cost after the above integration impact analysis, the methodology usually employed involves comparing the total power system costs before and after the inclusion of the technology being assessed. The difference in costs is often viewed as being one of the key components of the integration cost. As can be seen from these three approaches, they all achieve the same end goal – the estimation of an integration cost, although, the methodologies employed and the assumptions used can be significantly different.

Ascertaining power system costs under different scenarios and under a range of conditions is well understood and follows well-defined methodologies (Milligan et al. 2011). Production cost modeling can effectively capture the costs associated with additional reserve requirements and increased generator cycling as a result of increasing penetration of variable generation (Troy et al. 2010), but these costs also include the value of the new technology or resource itself (Milligan et al. 2011). However, an integration cost is usually only concerned with the additional costs imposed on the system and there is considerable difficulty in disentangling the integration cost from the other system costs. Thus, the manner in which ‘integration cost’ is defined and the method used to calculate system costs are not the issues; the concern is that integration costs may not be explicitly possible to calculate (Milligan et al. 2011; Milligan & Kirby 2009). This adds weight to the argument in Milligan et al. (2011) that ‘integration cost’ is more a concept than a definitive measure. The reason for this difficulty in calculating integration costs can be explained through a discussion regarding attempts to determine the integration cost associated with the variability of a resource (see section 4.2).

Furthermore, the underlying complexities within the power system itself and the interactions between generating resources necessitate the use of simplifying assumptions (Milligan et al. 2011) and these assumptions, upon which integration studies are predicated, can differ, as can the metrics used in the analysis. An understanding of the impact of these assumptions on the final result is imperative in all analysis and subsequent comparisons with other integration studies.

Defining the base case for any integration study is another one of the main difficulties and is often a source of conjecture. Meibom et al. (2009) and Soder (2005) highlight that study results are highly dependent on the reference or base case to which the system costs with the inclusion of the new technology are compared. For example, if the alternative to wind power is nuclear, the consequence of integrating wind would be lower compared to the case where the alternative is flexible gas (Soder 2005) as there is a greater fuel cost associated with gas plants. On the flip-side, if wind power is to be integrated with predominately baseload nuclear power, this would have a higher impact than if wind power was to be integrated into a system with large amounts of flexible gas (Soder 2005). As can be seen, of the characteristics of the alternative portfolio is not straightforward and consequently has an impact on the calculated operational costs (Meibom et al. 2009). It is acknowledged by Milligan et al. (2012) that the definitions of the reference or base cases used in integration studies ‘is an area of significant disagreement among experts in this field’.

It has also been learned from earlier integration studies that double counting, due to failure to properly account for benefits and impacts, can be a source of error. An example of error due to double counting is provided by Milligan et al. (2011): the balancing requirements of wind, solar and load are often determined in isolation, but this is only valid if they are all correlated perfectly. Aggregating the wind and solar generation and determining the balancing requirement of the resultant net load would more accurately reflect reality. As aggregation will be a critical part of DR, it extremely important to be aware of potential sources of errors. It will also be necessary to make many assumptions regarding the aggregation of the demand side resource and this could be problematic.
4.2 Integration Cost of Variability

Many renewable integration studies aim to determine the impact on the power system associated solely with the variability of renewable resources. This impact is usually expressed as a variability cost and is a subset of the overall integration impact. It is usually associated with the effect variable generation has on system operation and the operation and maintenance costs of conventional generation. For example, with large amounts of wind generation on the power system there is an increased requirement for reserves, the provision of which entails a cost, while the variability of wind can cause greater amounts of cycling of conventional generation, which manifests itself as an increase in the operation and maintenance cost of power plants.

In the literature, it is suggested that the costs of variability for wind can be addressed by comparing simulations with flat wind energy to varying wind energy (Holttinen et al. 2009). A simple, direct comparison is insufficient, however, as the value of the wind energy is also incorporated in this difference (Milligan & Kirby 2009). Milligan & Kirby (2009) conclude that there is a need to use an ‘energy proxy’. This approach involves comparing the costs associated with the integration of the new technology to the costs associated with the integration of another technology (often hypothetical) which provides the same energy output at a constant rate (Meibom et al. 2009) (i.e. a flat block of energy or proxy (Milligan et al. 2011)). This approach is outline in Table 1.

**Table 1: Common approach to calculate cost of variability associated with wind integration (Milligan & Kirby 2009)**

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<tr>
<th>Steps to calculate wind integration cost</th>
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<tr>
<td>1 Convert wind energy profile into a series of 365 daily flat energy-blocks</td>
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<tr>
<td>2 Run the production simulation model and record the production cost</td>
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<tr>
<td>3 Re-run the simulation, replacing the flat block with wind ‘as delivered’</td>
<td></td>
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<tr>
<td>4 The difference between costs in steps 2 and 3 is the integration cost</td>
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Despite, the widespread use of this ‘cost difference and flat energy block’ approach, according to Milligan et al. (2011), there have been no satisfactory results to date through use of the energy block method. This is because, according to Milligan & Kirby (2009), formulating an appropriate energy schedule consisting of flat energy blocks that can be used in the base case is challenging. The market value of the block of energy is fundamentally different from the value of the wind energy (Milligan et al. 2011) (Milligan et al. 2012). The reason for this is that for a flat block of energy, energy is available at all times during the day, even at peak periods when prices are high, while in the ‘with wind’ case, there may be times when more energy is delivered during off-peak hours when prices are lower (Milligan & Kirby 2009) resulting in different energy values between the two cases. It is suggested that the differences in the value of the proxy resource and the value of the actual wind energy becomes incorporated into the calculated cost (Milligan & Kirby 2009) thereby overestimating the integration cost. Thus it is also suggested that the results of this methodology are a mixture of value and cost (Milligan & Kirby 2009) and it is difficult to separate the two to obtain an integration cost.

Furthermore, using this proxy resource approach in integration studies with high wind penetration levels introduces large inter-day ramps into the proxy resource which are not real (Milligan & Kirby 2009) (see Figure 1) and analysis should account for this effect. A number of possible solutions were proposed by Milligan and Kirby (2009) including a 6-hour flat block along with rolling averages of 24, 48 and 96 hours and one week. It was found that the use of a 24-hour rolling average proxy resource may represent ‘certainty and near invariability, while eliminating artificial ramps’, which is what is desired, but there was little difference in the market value of all of the rolling averages and the daily flat block and thus the proxy energy value remains higher than the actual wind energy value (Milligan & Kirby 2009). The authors found that ramping in the 6 hour block approach is less severe than in the daily block approach, but that is still nearly double the actual ramping of the wind resource.

It is evident that it is exceedingly difficult to develop a proxy resource that satisfies both the certainty and energy value requirements simultaneously and Milligan & Kirby (2009) concluded that there is no adequate solution to be found by slightly relaxing these two requirements. The best ‘fix’ seems to be the application of the 24-hour rolling average with a correction in the calculation of the integration cost to account for the difference in energy value.
When calculating the cost associated with variability, the 6 hour flat block better approximates the real wind energy value than a daily flat block (Milligan & Kirby 2009, Reproduced with permission)

If the discussion is extended to demand response and it is decided that to determine the integration cost associated the variability of the DR resource, what should the proxy or energy block look like? Will the issues associated with a DR proxy be similar to those related to the proxy used for variable generation? Is there an alternative approach that can be taken? These are all important research questions if DR is to be incorporated effectively into an integration study.

4.3 Integration Cost of Variability and Uncertainty

In many integration studies, it may be necessary to determine the costs associated with both the variability and uncertainty of a renewable (or other) resource. The effect of variability (see previous section) could manifest itself as an increase in regulation or ramping requirements, while the impact of uncertainty would be seen as forecast errors and the effects it can have on economic dispatch and unit commitment. While the calculation of the cost of variability has been discussed, according to Meibom et al. (2009) without a stochastic power system model it is not possible to determine the costs of the partial predictability (uncertainty) of wind power generation. The work by Meibom et al. (2009) also suggests that a simplified approach is inappropriate to separate the costs of variability and the costs of uncertainty and that only an estimate can be obtained. Instead, the authors employ a more involved approach and determine the integration costs of wind and its components (cost of variability and cost of partial predictability) using three model runs. The first run involves stochastic wind power; the second run uses deterministic and time-varying wind power inputs; while the third run uses the constant energy method discussed earlier. The authors suggest that if wind is the only uncertain resource the second and third models are purely deterministic, thereby reducing the computational effort (Meibom et al. 2009). Keane et al. (2011) suggest that in analysis of systems with high penetrations of wind power, it is vital to take account of the uncertainty and the impact this has on the commitment and dispatch of the other units on the system.

There are undoubtedly stochastic characteristics associated with DR, but how should the uncertainty associated with the demand side resource be handled? It is undeniable, that the uncertainty and inherent temporal variability associated with DR will pose numerous challenges for extending integration study methodologies to include demand side resources, particularly when considering variability and uncertainty on both the supply and demand sides. This could increase the computational burden which could pose a problem and may necessitate the use of simplifying assumptions. The work by Kowli Meyn (2011), for example, uses a stochastic SCUC\(^2\) program to study the effects of using demand response as a means to integrate wind generation. It was found that it was necessary to make a number of assumptions to reduce the computational burden. Some of these simplifications include ignoring transmission constraints and neglecting generator forced outages.

\(^2\) SCUC – Security constrained unit commitment
An alternative to direct calculation of integration costs by the ‘difference in the cost savings’ approach is to simply avoid direct calculation of the costs associated with the impacts of integrating the new technology (Milligan et al. 2011). The emphasis is instead placed on the calculation of total system costs and benefits associated with the integration of the new technology (Milligan et al. 2011). It is likely that the more appropriate method for an integration study is to compare and contrast a number of different portfolios in a manner similar to that employed in the All Island Grid Study (Nabe et al. 2009).

4.4 Importance of a System Approach

Demand response is only one of a number of resources which could be used in conjunction to maintain the supply demand balance with increasing penetrations of renewable generation. Thus it is of crucial importance to assess the interactions between DR and the other resources to ascertain the true impact and value of DR. Sioshansi (2010) highlights that many economists have advocated real-time pricing on the basis of the associated economic efficiency gains and his work suggests that DR through Real-Time Pricing (RTP) and wind generation are particularly well suited to being implemented concurrently. It is demonstrated that wind generation and DR through RTP together result in ‘superadditive (social) surplus gains’ (Sioshansi, 2010). It is also crucial to study the implementation of renewable generation and demand response simultaneously so as to take account of the interactions and synergies between them. In a similar vein, it is necessary to ask should demand response be modeled simply as a means of directly balancing renewable generation? This would make the analysis simpler since the remaining system could operate as it did prior to the integration of the demand side resource (Soder 2005). However, this would not accurately reflect system operation in reality. Indeed according to Milligan et al. (2011), attempting to balance wind and solar in isolation from the load overstates the balancing costs of these resources and thus does not give an accurate indication of the associated operating costs.

The inherent complexities in power systems also necessitate the use of many assumptions. For example things such as power system stability, grid codes, market environment and transmission constraints are quite involved and thus require simplifying assumptions. There are also many variables associated with power plants, such as ramp rates, minimum up and down constraints, etc. which also need to be included in the modeling of the generators. Additionally, there are non-linear impacts between generators and loads (Milligan et al. 2012). Incorporating DR into the study would require that the key characteristics of the resource (as discussed in Section 3) would need to also be modeled. Different studies can make different assumptions and this complicates the comparison of the results. Furthermore, the definitions of reserve vary from system to system, and underlying assumptions upon which integration studies are predicated differ from study to study, adding to the difficulty in comparing studies. Some studies only focus on certain types of reserves, ignoring other types.

There are considerable topologies of demand response programs and it has been found that many places in the literature categorize the programs differently and according to different characteristics. This considerable variation leads Thanos et al. (2013) to raise the point that there is a significant challenge in evaluating DR programs holistically. The alternative, to evaluate the programs separately, is unacceptable since, ultimately, any program will be integrated into the larger power system and thus there will be interactions and interdependencies and the programs will form a small part of a larger portfolio of resources.

The benefit of using a system approach is that it effectively allows the different technologies to compete with each other. Demand-side options would need to compete against strategies already in use or contemplated for future integration of large volumes of variable generation resources (Cappers et al., 2011). It will also be necessary to account for the market interactions between DR and the alternatives in integration models in order to determine the true value of DR.

4.5 Comparing Variable Generation Integration Studies and Demand Response Integration Studies

Perhaps it is necessary to aim to maximize social welfare, (in Sioshansi (2010) social welfare is defined as the difference between consumer surplus and total generation costs) as oppose to minimize cost due to the participation of the consumer side and thus to account for the changes in consumer surplus? De Jonghe et al. (2012) suggest that when short-term demand response is integrated into the generation technology mix model, minimization of generation costs does not yield sensible results, because that would disregard the benefits consumers receive from electricity consumption. The notion of using the change in social welfare as a key performance indicator was also suggested in Thanos et al. (2013). Similarly, Su & Kirschen (2009) propose a method for quantifying the effect of demand side participation on various market participants; A day-ahead, market-clearing
mechanism is suggested that aims to maximize social welfare (Su & Kirschen, 2009). In order for this to be realized, greater data pertaining consumer behavior and consumer’s price elasticities of demand would be required and sourcing this data could prove to be a major barrier to future integration studies. While wind data is readily available, it has been indicated in the literature that solar data is limited and it is likely that there will be a limited amount of suitable DR/DSM data available for use in integration studies (see Section 4.6 for more discussion on DR data availability).

With the advent of DR programs, there will be a probable change to the structure of contracts in the future (Milligan et al. 2011), particularly in light of new players such as load serving entities (LSEs) or aggregators, players. Grid codes and system operating strategies may also change in the future, furthering the need for speculation and assumptions. All of these issues present challenges for extending integration studies to include demand response programs.

Cutter et al. (2012) suggest that while customers have been shown to be price responsive, this responsiveness is inconsistent. Thus, the value consumers place on electrical energy is wholly unpredictable. The need to incorporate irrational consumer behavior in demand side models represents a major paradigm shift from the traditional integration study and could provide some challenges, requiring interesting and novel solutions.

4.6 Issues with Establishing DR Baselines and Obtaining Data for Use in Integration Studies

The literature raises concerns regarding DR baselines and suggest that the challenge of establishing a baseline for DR may be a serious impediment to the implementation of DR and to the development of robust methodologies for determining the true value of certain DR programs in the market, while Cutter et al. (2012) suggest that this particular problem is ‘eternally controversial’. Indeed, it is suggested in an EnerNOC (2011) report that a DR baseline plays an important role in determining the value DR brings to the electrical system.

It should be stressed from the outset, that the establishment of DR baselines is only a major issue for certain DR programs, for example those which are event-based. Grimm (2008) states that direct load control DR programs typically have responses that are predictable, thus the issues surrounding baseline estimation do not apply. It is understood that it is possible to obtain a reasonable baseline for commercial and industrial loads, where the loads can be directly controlled and closely monitored, while for small devices and for devices with irregular or unpredictable power consumptions, establishing a robust and accurate baseline is much more difficult. Small loads with irregular power consumption include heat pumps in a residential home and the charging of an electric vehicle. Ultimately, when a load is dependent upon consumer behavior and where the power consumption cannot be directly controlled, it is typically more difficult to establish a baseline.

While, the generation of DR baselines may not be the significant barrier to the development of DR that it is touted as being, obtaining sufficient data poses an issue for the modeling of all DR programs and, in this regard, data availability could be seen as being the key concern.

While it is acknowledged that baseline establishment is not a major issue for all DR programs, many of the DR programs currently being implemented fall into the ‘event-based’ category and such programs will likely continue to be popular into the future. Federal Energy Regulatory Commission’s definition of a baseline is ‘an estimate of the electricity that would have been consumed by a customer in the absence of a demand response event’. The key point to be taken from this definition is the use of the word ‘estimate’. It is inherently challenging to measure or calculate what would have occurred and thus, fundamentally no baseline is perfect (EnerNOC, 2011). Sufficient DR data would be required in order to determine baseline conditions to allow development of methods to assess DR availability and performance (Cappers et al. 2009) for certain DR programs.

Demand response performance is computed as the difference in the actual demand level and the baseline (Martinez & Hamilton, 2013), so, effectively, consumers are being paid for what they do not use (Chuang, 2007). Thanos et al. (2013) question whether baseline predictions are correct. They suggest that the average demand of the baseline and the real demand have no direct relation. They also suggest that baseline calculations may not even be possible for different types of end-use customers. The implications of inaccurate baselines can be far reaching: the performance of a particular program would be not be accurately ascertained and, for certain programs customers, baselines form the basis for customer remuneration for their participation. Without a robust method for determining the baseline, program participants could be under compensated, reducing customer will-
ingness to participate or they could be over compensated thereby increasing system costs, reducing some of the benefits ascribed to DR programs.

Baselines are also suggested as forming an important part in the scheduling and dispatching of event based demand response resources and could be used in system planning (Martinez & Hamilton, 2013). Thus without an understanding of the available capacity of DR, this will represent another uncertainty for system operators and will impact upon the value of DR for the system.

Much of the discussion on establishing DR baselines to date in the literature has been focusing on DR programs where there is prior knowledge that there will be a DR event on a specified day. Grimm (2008) discusses the relative merits and flaws of a number of methodologies employed by ISOs in the US for calculating the baselines for event based demand response programs. In many of the methodologies for determining the baseline employed by the ISO/RTO/ utilities (eg. New York ISO, ISO New England), consumers are made aware of the need to reduce demand in the days prior to a DR event. Thus these programs are purely event driven. Such programs would necessitate a clear understanding of the performance of different demand units, so as to schedule responses from the different participants. Without a baseline, it will not be possible to do so robustly. According to Mathieu et al. (2011b), baseline models which are generated by averaging electricity consumption for a particular load over a number of days can be biased and the authors advocate the use of regression based baseline models to overcome this. Such models may be required when incorporating DR in an integration type study, particularly if investigating event based DR programs.

Baselines are often calculated on the basis of historical data. This suggests that considerable data may be required in order to establish a robust baseline or baseline model. For systems where there has been limited experience with DR programs, there may be a significant deficit in data availability. As previously alluded to, according to Mathieu et al. (2011b), many utilities use simple DR baseline models which are based upon averaging demand data over a number of days. There are five different methods for calculating DR baselines currently employed by utilities and are discussed in EnerNOC (2011) and Grimm (2008). All of the methods discussed require the calculation of a baseline and committed capacity for each individual ‘demand response unit’, for each individual customer or each individual site by the aggregator or utility. If the residential sector is to participate and if individual baselines are to be established it is clear to see that there would be a dramatic increase in the data required. This clearly advocates the need for an aggregator, curtailment service provider (CSP) or LSE so that the burden of storing and acquiring this data is not placed on the transmission or distribution system operator. Perhaps the considerable data requirement suggests that focus should be placed on larger demand units such as units in the commercial and industrial sector, excluding participation from the residential sector. An integration study which includes demand response should analyze all three sectors and this should inform whether there is merit in pursuing DR from the residential sector. There is significant work to be performed in establishing if there is a business case for aggregators to operate under the current baseline calculation methodologies. An integration study approach could provide a means for this business case assessment.

More sophisticated baseline modeling methods have been proposed, but are seldom used in practice (Mathieu et al. 2011a). According to EnerNOC (2011), accuracy, simplicity and integrity are crucial for baseline calculation, but it is highly probably that all three cannot be achieved simultaneously and that a compromise between accuracy and simplicity will be required. Indeed, according to EnerNOC (2011), no baseline is perfect and it is important to be aware of any flaws in the baseline models/calculations so that they can be taken into account and compensated for. Thus, despite the apparent advantage regarding the fact that the commercial and industrial sector loads are generally large loads and that such facilities already have energy management systems in place, the baselines can still be predicated upon models with inherent errors. It is shown that measured DR parameters exhibit variability not only due to real variability in the response but also because of errors in the baseline model (Mathieu et al. 2011b). This is evidently problematic. If the variability was purely due to unmodeled load variability, the power system operator could account for this (Mathieu et al. 2011b). However, real DR variability imposes further challenges on the system operator who is tasked with maintaining the supply—demand balance in the midst of ever increasing degrees of uncertainty and variability, a situation which is made worse by poor baselines and lack of data. According to Mathieu et al. (2011a), this could entail greater reserve requirements, which would be a case of DR exacerbating the problem it set out to mitigate. It has been noted that it is unusual to analyze the errors associated with DR baseline models (Mathieu et al., 2011a). Perhaps this is a result of the complexities involved. The more reasonable explanation for this is the fact that there have to date been limited numbers of DR field studies and thus, as mentioned earlier, limited available data for establishing baselines.
Even if sufficient data was available, there could be implications for its accuracy. According to Cappers et al. (2009), participants have historically overestimated their likely performance during declared curtailment events. Additionally, the problems associated with asymmetric information may need to considered in the analysis of DR as individual customers will always know more about their true baseline than the load serving entity (LSE) or aggregator and can likely profit from that knowledge (Schad et al. 2009). It is suggested by Grimm (2008), that many programs have attempted to minimize the participants ability to game the system and in many of the baseline methodologies examined, it is also found that they require an adjustment, post event, in order to increase the accuracy of the estimate. It might be interesting to assess whether aggregation of a large number of demand responses can eliminate or at least reduce the uncertainty associated with baselines.

Determination of the shape of the demand curve with accuracy is practically impossible, according to Kirschen (2003), particularly so for electricity. This has serious implications for modeling of demand response and likely requires either significant amount of data or a novel solution. In the literature, a number of demand response related studies, for example Dietrich et al. (2012) and Sioshansi & Short (2009), are founded upon assumptions regarding price elasticities of demand in order to mirror the market environment whereby customers can respond to price signals and shift their demand. One of the issues is that, as Dietrich et al. (2012) suggest, elasticities differ by customer-type, direction of demand variation and time of day. It is probably that this is the reason for the considerable variation in estimated price elasticities of demand which have been observed in the literature (Andersen et al. 2006). This can pose significant problems. Furthermore, according to Moghaddam et al. (2011), in many studies, the price elasticity of demand is often represented as a pre-set constant value, which is a simplified representation of reality. The current lack of data pertaining to elasticities has been acknowledged as an issue when attempting to classify customers according to ‘observed price responses’ (Boisvert & Neenan, 2003). There is clearly considerable work to be undertaken in acquiring this knowledge and elasticity data before an integration study incorporating demand response can begin in earnest.

Many integration studies look at future power systems scenarios and inherently there is considerable uncertainty and limited data. This can be problematic and can be a source of error as historic data for renewable generation and demand response programs is extrapolated or scaled up to levels which are deemed appropriated for future systems. Additionally, data is often generated using statistical approaches. It is evident that considerable thought and effort will be required for the portfolio selection stage of the demand response integration study. This may require a number of assumptions which will require thorough and robust validation.

5. Discussions and Future Work

There are a number of major research questions pertaining to DR and a number of these questions will be explored in future work by the author: What is the integration cost and benefit of DR? What is the value of DR for a generic power system? With this in mind, is there sufficient value for DR to operate in energy and ancillary service markets? What would the market value of DR need to be in order to make it viable? Another question is whether the ‘integration cost’ of demand response includes the cost of the smart meters and advanced metering infrastructure (AMI)? In which case, this would not be a power system level issue, but it could affect consumer acceptability and willingness to invest in DR technology. Along similar lines, is there an opportunity cost associated with demand response? If there is no opportunity cost and there is only an upfront, once-off capital cost, perhaps DR should not operate under market rules as marginal cost pricing would not be suitable for obtaining a response from the demand resources. Perhaps they should instead receive a capacity payment and should operate according to grid codes, thus making DR provision of ancillary services mandatory? However, market rules are not the only barrier to demand side participation in ancillary service markets (Macdonald et al., 2012); consumer willingness and whether or not DR is justified are other barriers that need to be considered.

Is there an ‘integration cost’ associated with DR or is there a need for a new parameter or concept to replace cost? Perhaps social welfare, as suggested by Sioshansi (2010) and Thanos et al. (2013), could be a more suitable measure of the cost and impact of the integration of DR. Sioshansi (2010) suggests that the change in social welfare as opposed to the change in operation costs is a more appropriate metric to use in the evaluation of wind integration, forecast errors and real-time pricing. It is acknowledged by Madaeni & Sioshansi (2012), that while the difference in system operating costs between a case where imperfect wind forecasts are used and a case where perfect foresight is assumed is often used as the standard measure of wind-uncertainty cost (essentially integration cost of wind as described earlier), the difference in social surplus is a better metric when dealing with real-time pricing (and by extension, demand response).
Another consideration should be network latencies. Is it necessary to incorporate issues relating to communication network latencies? The work by Eto et al. (2012) discusses the Demand Response Spinning Reserve project in Southern California. It was found in this case that there were a number of fixed latencies involved in dispatching the signal to curtail load from the system operator to the demand side. This minimum time to operate a dispatch sequence was found to be 100 seconds (Eto et al., 2012). Depending on the time steps of the simulation involved in the integration study, the inclusion of these latencies could be crucial to the overall result. While these latencies could affect the end result, it is likely that their inclusion will also add to the dimensionality of the computational problem. It is probable that these latencies will be neglected, as has been the case to date in much of the literature.

Out of the four types of DR programs, as identified by EnerNOC (2009), the performance metrics of three programs are predicated upon differences between baseline and actual loads. The only programs which do not involve baselines are programs through which ancillary services are procured. However, MacDonald et al (2012) suggest that baselines calculation methods are substantially different for DR in ancillary service markets than in other types of DR. There is clearly a significant contradiction here and future work will look at ascertaining if baselines are required for DR provision of ancillary services. If baselines are not required, it would be interesting to research whether this fact alone advocates the use of DR for the provision of ancillary, neglecting other DR programs. Determination of where the value of DR lies could also inform the discussion of which DR programs should be concentrated on.

There are a number of assumptions which will need to be made as regards demand response baselines and thus results are necessarily going to be heavily predicated on these. So will it be possible to definitively state what the cost/ value of DR is? Or will the results be ‘for the particular case examined’? In which case the results would not be generic and any recommendations are unlikely to be implemented in reality.

Andersen et al. (2006) advocate focusing DR activities on specific large consumers, consumers who are capable of responding appropriately to real-time prices. This is, in effect, exploiting the easiest resources first. It is clearly of importance to model such resources accurately as they are likely to form a large part of the overall DR resource. The work by Sioshansi & Short (2009) demonstrates that implementing DR through RTP in the industrial and commercial sectors provides about 64% of the total benefit of exposing industrial, commercial and residential sectors to RTP. This supports the views expressed by Anderson et al (2006). This could prove to be a very significant result and further research could prove that there is no major benefit or value in extending DR to the residential sector and thus DR could be shown to be a niche application. On a related note, the work by Cappers & Ellis (2009) suggests that as the penetration level of DR increases, the capacity value of DR can actually decrease, while at lower DR penetration levels DR programs ‘provide almost a MW of capacity value for a MW of DR’. This decreasing return to scale suggests that there is an optimal penetration level of DR and future integration studies which incorporate DR could inform what this optimal level is. Additionally, as already mentioned, despite the small size of ancillary service markets in the US, they are usually quite robust to small changes in the amount of resources in the market because of the co-optimization of energy and ancillary services markets and because of their size relative to the large energy markets but there is likely a penetration level of low cost resources at which the marginal cost price in the market will dramatically approach zero. This clearly indicates there is an optimal penetration level for DR resources, which is a key research question.

Furthermore, according to Schad et al. (2009), it is highly probably that the amount of DR resources that market participants are willing to provide is likely to be less if DR resources are required to participate in the energy and ancillary service markets under the same terms and conditions as generation unit owners. This could necessitate a restructuring of electricity markets and system rules and codes in the coming years if demand response is required to play a major role. Market design and market conditions are rapidly evolving in light of new technologies and improved system operating procedures. With this in mind, it will be difficult to predict the market design in 2020 or 2035 and thus integration studies which focus on future portfolios will be based on underlying assumptions regarding the market. It may be worth assessing the integration of demand response with and without a market in order to determine optimal future market design.

It is also likely that it will be impossible to consider all the necessary parameters and variables in integration studies, for computational reasons and due to difficulties in obtaining sufficient data. The difficulty including all of the above requirements in a study leads Soder (2005) to conclude that all integration studies will necessarily be based upon assumptions and thus integration cost’ calculations will always be approximations.
The numerous uncertainties associated with power systems need to be included (Soder 2005), including variable generation and the demand side, in order to realistically assess the impacts of novel technologies on the power system.

6. Conclusions

Demand response is multi-faceted and has important characteristics that distinguish it from thermal generators. There are numerous types of DR programs and mechanisms through which to exact a response from the demand side, as well as different market interactions. As many different programs are likely to be implemented in reality, it is suggested that a portfolio approach is required in order to account for interactions and interdependencies between different programs and load types.

Throughout this literature review it has been found that the term integration cost can be misleading and is often a source of contention. Furthermore, it is generally acknowledged that the integration of variable renewable generation has an impact on power system operation; however the methods of calculating the associated integration cost can also lead to disagreement. Additionally, many of the integration studies in the literature define integration costs differently and direct calculation of the costs is extremely difficult. There are other issues pertaining to integration studies that need to be borne in mind and these have been highlighted and discussed.

It has been illustrated that it is vital to determine the value of DR and an integration study approach is suggested as a means in which to do so. In this regard, there is a need to extend integration study methodologies to incorporate demand response programs and measures and this has been showed to be non-trivial. There is merit in using an integration study as the basis for DR evaluation, due to the significant body of work in the area of VG integration and the many lessons learned from previous studies. However, there are issues that would need to be addressed when including DR in the methodology.

As a result of decreasing returns to scale, there is likely to be an optimal level of DR, a level which is possibly system dependent. Furthermore, it is necessary to accept the possibility that DR could have very limited applications, because, firstly, it could have very limited revenue streams and, secondly, it could suppress the prices in the markets in which it is operating.

The lack of available data pertaining to DR programs and price elasticities could pose a major challenge for accurate estimation of the DR resource and thus could impact upon the robustness of DR integration studies.

7. References


