PARAMETERISED RISK SHARING IN SMART DISTRIBUTION SYSTEM INVESTMENTS

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ABSTRACT

The increasingly varied profile of distribution system users, including those deriving commercial revenues of their use of system – embedded generation and demand response – changes the value proposition of distribution system investments.

In parallel with this evolution in the use and value derived of the distribution system, developments in distribution system control and automation technologies increase the potential for targeted investments, offering relatively discrete benefits to small subsets of customers. These coincident technological, systemic and market developments may offer the potential for synergistic infrastructural investment propositions, better reflecting the needs and values of investors and beneficiaries.

This paper presents a model to quantify the benefit of investments in smart distribution system automation and control technologies, which accurately reflects the relative value and risk from the perspective of different stakeholders including the system operator, demand customers and embedded DER.

1 INTRODUCTION

1.1 Investment risk and cost allocation considering DER and smart investments

As exemplified by ongoing scrutiny of regulatory models arising of increasing DER, distribution development strategy and cost allocation is an increasingly complex issue. A recently produced report prepared for the Directorate General for Energy of the European Commission [1] highlights this complexity of determining the appropriate service levels and allocation of associated costs amongst users.

Although significant efforts have been dedicated to establishing causality and appropriately assigning costs in the development of network capacity to manage growth in embedded generation in recent years, investments in incremental service quality improvement, particularly those delivered by means of "smart" investments, remain an area of uncertainty. Establishing a sustainable investment model will require evaluation techniques and investment models which achieve allocative efficiency reflective of the benefits of these investments.

Efforts have been made to achieve this [2], [3] though these have focussed more on quantification of societal benefits in terms of policy reflective KPIs as opposed to addressing commercial benefits and allocation.

Smart network technologies allow for targeted investments, potentially giving rise to the potential for new regulated and commercial models for local service level agreements or cooperative investment – service *quality* mechanisms analogous to the bespoke service *capacity* models demonstrated in [4] - [5]. However by definition smart investments – new and innovative technologies whose benefit relies on the actions of all network users [6] – have inherent risks outside the control of system operators, which influence the benefit arising of a given investment. They rely on the coincident occurrence of somewhat stochastic events – wind resource availability, network faults and customer behaviour.

Increasingly regulatory measures are adopted to incentivise such investments in the interest of promoting environmental sustainability or innovation [6], reflective of the fundamental relationship between investment risk and expected rate of return [1]. However such measures do not yet appear to leverage value proposition linking costs and benefits, and risk placing additional costs (and risk) on existing customers. This paper aims to address the allocation of such investment risk reflective of the value derived by a new class of distribution network users – distributed energy resources (DER).

2 INVESTMENT MODELS & RISKS

2.1 The value of network reliability

Accurate valuation of the benefit of improved network availability for demand customers is acknowledged to be challenging [7]. However comprehensive work has delivered models to reflect the value of network reliability improvements reflecting load composition [8], connection point [9] and applying probabilistic techniques [10] Alternative models value lost load as a function of the retail cost of forfeit energy consumption [9]. Reliability insurance is an innovative concept which aims to allocate risk according to perceived value derived of such investment [11]. However this work is limited to the value returned to conventional demand customers.

From the perspective of DER customers, constraint due to a lack of network availability is a recognised investment risk. There are many examples, including [12], proposing means of minimising such constraint through balancing mechanisms, or as in [13] through voltage control. Beyond its prevalence in research, this risk is increasingly being realised on distribution systems across Europe due to rapid growth in levels of embedded DER [14], [15] increasing the cost and risk associated with either socialised support mechanisms or commercial investment.

2.2 MV automation field trials and investment model

MV Network automation aims to reduce the impact of outages, however investment risks arise depending on the performance of these investments on the ground, and the financial return offered.

So as to mitigate these risks, ESB Networks has undertaken extensive field demonstrations of smart technologies to improve continuity. Pilot changes in

neutral treatment have been demonstrated to deliver improvements of up to 66% in SAIDI and 75% in SAIFI [16]. Field deployments of single phase reclosers are addressing the single phase fault rate – approximately twice that on three phase networks which comprise just 33% of the total system [17]. These trial findings have reinforced the evidence that transient faults to comprise 80% of all faults on rural overhead networks, and proved effective in avoid consequential outages on these conventionally fused networks. The delivery of self healing networks has been demonstrated since 2009 [17] resulting in 40% reductions in SAIDI and 53% SAIFI on the networks affected where this investment is made.

The model used to evaluation the value of such investments is a conventional one applying a value indicated by the Irish Regulator to each avoided customer interruption and customer hour lost. To reduce the risk of inefficient investment, a robust benefit : cost ratio (2+) is generally required. However such a model fails to capture value as perceived by customers, a function of time varying demand, and the presence or otherwise of demand response or embedded DER who forfeit revenues while supply is lost.

3 INVESTMENT VALUATION MODEL

The investment valuation model developed in this work attributes a value of supply continuity to each network user which is a probabilistic function of their loss of energy based revenues derived of the system due to outages. For each DER, the annual benefit of improved continuity is calculated using equations (1) - (5).

$$E_{DER} = \sum_t E_{DER,t} = \sum_t E(n)_{DER,t} + E(d_t, g_t)_{DER,t} \quad (1)$$

$$E(n)_{DER} = \sum_t c(n)_t . p_{DER,t} \quad (2)$$

$$E(d,g)_{DER} = \sum_t c(d_t, g_t) . p_{,DERt} . d(DER, g, d) \quad (3)$$

$$0 \leq c(n)_t + c(d_t, g_t) \leq 1 \quad (4)$$

$$O_{DER} = \sum_t (\%l_t . E_{DER,t}) \lambda_t + \left((1 - \%l_t) . \%l_t . E(d,g)_{DER,t}\right) \lambda_t \quad (5)$$

Where

E_{DER}	DER kWh output
$c(d_t, g_t)$	capacity depending on local demand and generation per unit
$c(n)$	physical network capacity for DER per unit
g_t	underlying generation on the network
$p_{DER,t}$	available power of the resource
$\%l$	percentage of load lost due to an outage
O_{DER}	cost of outages over time to a DER
λ_t	Output value at time t

The value of lost load may be calculated in one of two ways:

$$V_{ll} = \sum_t EENS_t \, \lambda_t \quad (6)$$

$$V_{ll} = \sum_r p_r \, CDF_{dur} \quad (7)$$

Where

$EENS_t$	Energy (kWh) not served at time t
CDF_{dur}	Customer damage function for outage duration
λ_t	Energy cost at time t
p_r	kW demand at time of interruption *r*
V_{ll}	Value of lost load

The value of investment is then calculated as the difference between outage costs with and without investments to reduce the frequency, duration or magnitude of supply interruptions.

4 DEMONSTRATION & DISCUSSION

4.1 Test network & simulation

The evaluation method is tested in 17520 half hourly time series simulations on a rural network in the mid-west of Ireland, with a peak demand of 7.3MW fed through two 5 MVA 38kV/20kV primary transformers. A total of four medium voltage outlets supply the 4767 predominantly residential customers via 306km of 20kV networks. The modelling uses the measured historical load profiles and coincident fault records for the network.

Each of the three technologies introduced in 2.2 are modelled on the network at the performance rates demonstrated in ESBN field trials. The customer damage function applied is the residential model arrived at in [19] inflated and converted to a 2014 euro value. λ_t is a weighted average residential unit energy rate based on Irish residential electricity prices [20]

The embedded generation modelled is wind generation, using historical wind output profile information from this region In addition to wind with a firm connection, with no expected constraint, a non-firm resource is modelled, whose output is constrained when there is insufficient built capacity or local demand to balance it. λ_t is set as the Renewables Feed in Tariff rate applicable in Ireland in the base case, and the contemporaneous energy market price in a sensitivity case.

In a medium term scenario modelled the peak non-firm wind connected is equal to the thermal capacity of the second transformer in the station plus the peak demand, less the summer valley load (as such, the total aviailable capacity net of that capacity dedicated to firm connected wind). In the "future" scenario, the non-firm peak output capability is 1.5 times the peak load, analogous of a case where potentially 40%+ of energy demand on these networks could be fed by local non-firm generation, allowing for diversity between demand and generation.

In the absence of developed, commercial demand response of any scale being active at present, the profile of demand flexibility has been modelled as following market electricity price data for the period of simulation. In the interests of decoupling the value of network

reliability investments insofar as they accrue to different resource operations, upwards and downwards responsive demand are separately analysed.

Upward demand response in the medium term scenario is consistent with the UK government Committee on Climate Change (CCC) pathway uptake for 2020 – 2030, at 20% uptake of EVs, with a charge rate of 3.6 kW which can be controlled or shifted to deliver demand response for up to 2 hours per 24 hours. Controllable electric heating uptake is modelled at 20% of households, consistent with the CCC "balanced transition" model by 2025, with a peak demand of 3kW of which 2 hours charging can be shifted to deliver demand response. Finally, an additional 1kW per demand responsive household is allowed for in 1 hour of the day. It is assumed that adhering to customers lifestyle requirements results in a capacity factor of 0.50 being achieved over a 14 hour period when some level of load shifting is delivered each day. In the future scenario, consistent with the CCC 2040 target, EV uptake increases to 100%, charge rates increase to 5.2kW, an additional 1kW of controllable electric load is allowed for. The uptake of controllable in-home technologies delivering demand response increases to 100% of households.

The downward demand response is modelled reflective of the potential demonstrated by the Irish smart metering customer behavioural trials completed by ESB Networks in the medium term scenario. A peak demand reduction of 14.4 % was delivered by subset of customers with the most effective demand response stimuli and price signals, and a load reduction of 2.5% was found to be achievable average over all time periods. In the high uptake case, an additional 10% peak reduction is allowed for.

The scheduling of these resources, though beyond the scope of this work, is modelled as accurately incorporating market signals, users behavioural requirements and typical periods of network constraint. When there is insufficient network capacity present for coordinated responsive demand it is automatically constrained to the maximum for which there is capacity, as in the conceptual architecture presented in [21].

Such constraint of demand response arises on the test network during periods of high load, where upward demand response would overload the network, or (very infrequent) periods of exceptionally low load, where downward demand response below a minimum base load value would result in local or regional embedded generation inducing overvoltage or exceeding network thermal capacity.

The particular model presented only addresses constraints arising at primary transformer level, neglecting lower voltage constraints – medium and low voltage thermal and voltage constrained capacity – whose limits are beyond the scope of this paper.

λ_t is modelled as the difference between the market electricity unit rate at a point in time t and a rolling average market electricity unit rate over a 24 hour period. As such, no loss of revenue is attributed to outages which occurred when there was no market signal incentivising flexibility.

In addition to the medium and future scenarios described, an "increased capacity" scenario is modelled, where thermal capacity has been increased from 2x5MVA to 2x10MVA to allow for increased DER penetration.

4.2 Results & discussion

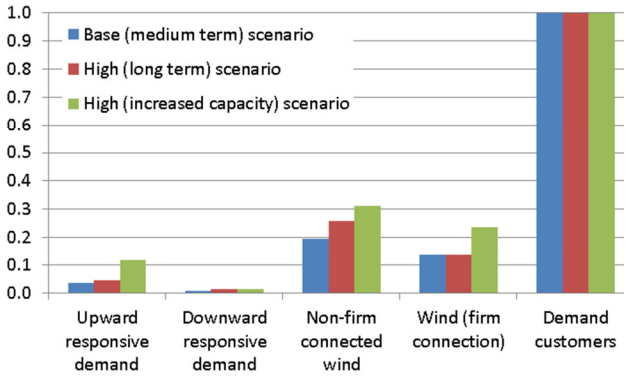

Figure 1: Absolute value of investment relative to benefit seen by demand customers.

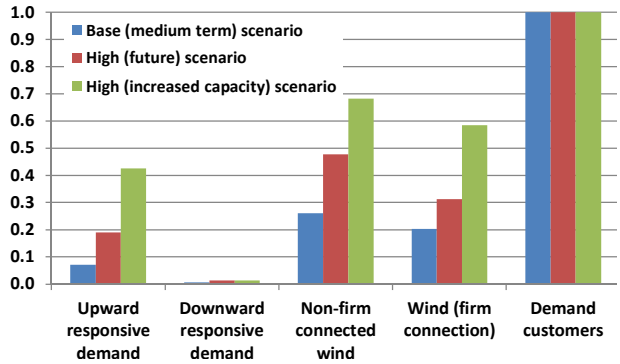

Figure 2: Benefits relative to benefit seen by demand customers – reduced electricity consumption scenario.

The absolute additional revenues seen by different network users as a proportion of the monetised benefit seen by demand customers is illustrated in Figure 1 based on the actual demand on the network and a scenario where load is 30% lower, as is the case on many networks of this type, in Figure 2. Presenting both results illustrates that stakeholder benefits relative to demand customer benefits will vary significantly as a function of demand. Migration or energy efficiency will see the distribution of benefits amongst network users weighted increasingly towards these non-conventional network users.

The technology found to have the lowest payback period was the change of neutral treatment described in 2.2, at 4 – 5 years in the high and medium scenarios respectively, based on the total cumulative benefit to all beneficiaries.

This increases to 6 – 12 years under the reduced electricity demand scenario.

Borne only by demand customers, the payback period would be 7 years, or 12 – 22 years with lower electricity demand, based on the total financing cost of the project, as considered in the Spackman approach to cost benefit analyses [22]. If a payback period of 12+ years neglecting the multi-stakeholder were not be sufficient to progress the project, DER network users would forfeit up to 1.4% increases in annual revenues..

The payback period for the different technological investments presented in 2.2 range from 4 to 25 years, however the benefit as seen by different stakeholders relative to each other remains steady. Non-firm wind generation sees the second highest absolute financial benefit, followed by wind generation, upward demand response and finally downward demand response.

Should the feed-in tariffs used to quantify the value to generation resources be discontinued and these resources become variable price takers, albeit with priority dispatch, then the return seen by wind, firm and non-firm, would increase to 24 – 38% and 16 – 28% respectively, depending on scenario; this is well in excess of the values shown in Figure 1.

Alternatively, applying a nonlinear CDF as outlined in 4.1, the customer benefit would increase by a factor of 4, such that the relative benefit seen by other network users would reduce. This highlights the importance of establishing accurate valuation of resources, accounting for customer preference, the economic value of electricity supply, and the expected duration and extent of any policy measures which may distort the apparent value of a given resource or stakeholder.

The value of the smart neutral treatment investment from the perspective of different network users expressed as the resultant increase in total annual revenues is illustrated in Figure 3, or increased annual use of system in Figure 4.

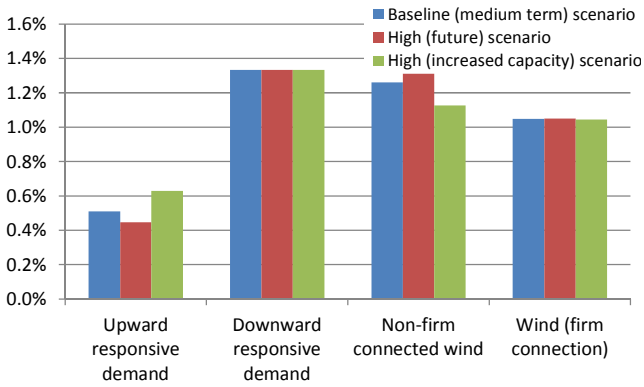

Figure 3: Increase in annual revenues as a result of change of neutral treatment.

Although Figure 1 indicates that the highest absolute benefit is seen by demand customers, the return relative to total annual revenues is highest for downward regulating demand response under all scenarios, and non-firm or firm wind generation users see a comparable rate of return as regular demand customers.

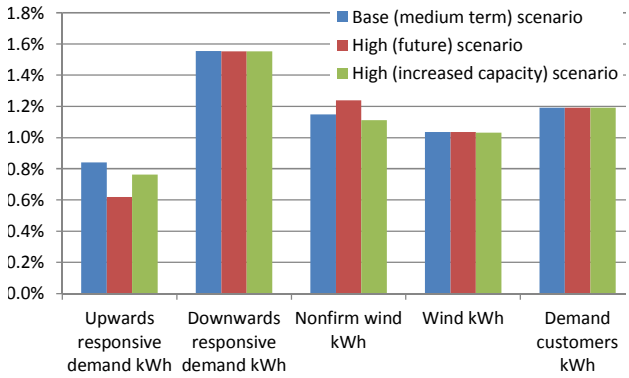

Figure 4: Increase in annual use of system as a result of change of neutral treatment

These varying perceived levels of benefit amongst different stakeholders highlight the potential for allocative efficiency without applying a Ramsey pricing principle, which is identified in [1] as being discriminatory.

4.3 Benefit value sensitivity to resource parameters

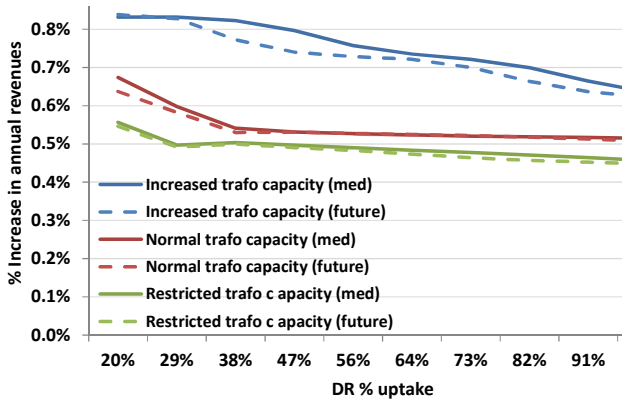

Figure 5: Increase in revenues from responsive demand increases as a result of continuity improvement investment

The most complex relationship between resource, the determinants of capacity and the value of improved continuity applies to upward regulating demand response (see Figure 5). Increased transformer capacity increases the value of improving continuity, as revenues increasingly become a function of resource availability with reduced thermal constraints.

Increases in the DR resource without corresponding increased network capacity reduces the *relative* value of improving continuity (along the positive x-axis, or from medium to future scenario plots). As the resource increases, thermal capacity more frequently limits the potential to increase load, thus reduced resource availability due to loss of supply is of limited consequence. Nonetheless, the *absolute* financial benefit

of improved supply continuity increases with DR uptake (Figure 6)

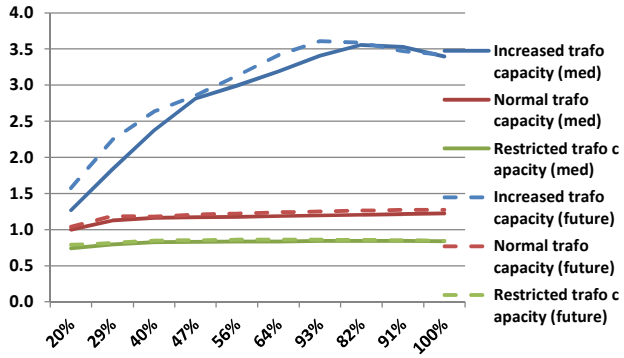

Figure 6: Absolute value of increased output due to continuity improvement per unit of base (medium term) case

The relative value of improved continuity remains near constant for both embedded wind generation with a firm connection capacity and downward responsive demand, at 1% and 1.3% increases in total annual revenues respectively, regardless of increases in resource capacity. This is due to output of both of these resources being almost entirely a function of resource availability. This only holds for downward demand response so long as it is rarely restricted. In a sensitivity where growth in embedded generation increases the minimum load threshold for stable network operation, the value of improved continuity increases with increased load reduction resource capacity. Maintaining the minimum load necessary to balance generation will constrain downward DR, thus loss of supply anywhere on the network reducing the base load would increase the probability of DR being prohibited by local network management.

Finally, as the non-firm generation resource increases, the relative value of supply continuity investments increases due to the increased reliance on local demand remaining on the network to balance wind output.

In summary, this paper presents a method for the parameterisation and quantification of distribution of network investment benefits amongst network users to inform allocative efficiency in investment models..

The results of a test application of this method modelling medium voltage automation and control technologies to improve supply continuity indicated that the benefit accruing to DER may be substantial relative to the benefit accruing to demand customers. Given the results observed, there is the potential for further work to integrate this method into a generic investment model which allocates costs in a manner more reflective of the value accruing to different network users and which allows network users to influence network investment decisions based on the expected impacts on their individual revenue stream.

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