# The Impact of Distributed Generation in Scotland (on the Energy System, to Consumers and to National Emission Levels)

**E. Robertson*, L. Anderson and S. Galloway**
**Institute of Energy and Environment, University of Strathclyde,**
**204 George Street, Glasgow G1 1XW**
**UK**

## SUMMARY

In 2011 the Scottish Government committed to a programme that by the year 2020 100% of electricity consumed in Scotland is to be from renewable, zero-carbon sources. This target alongside UK and European targets mean that there is now a drive towards the installation of large and small scale renewable generation. In the UK, domestic consumption accounts for 30% of the total electricity. Consequently, there is a need for more active participation in the energy sector from domestic customers. Secondly, in Scotland, and the UK, with large scale penetrations of Distributed Generation (DG) there will be a transition from the current 'top down' energy distribution system to a newer approach.

This paper has investigated the feasibility of high penetrations of DG in the energy system in Scotland, as well as the advantages storage facilities can offer to it. Results have demonstrated the influence that the change in system use will have on regional and local emission levels and the final costs to consumers. Results have also demonstrated the need for reinforcements to the system as well as an inclusion for local electrical storage.

The modelling tool SREN is used to investigate the cost implications between the East and West coast of Scotland systems and the different impact that large scale DER penetration has in the two Scottish regions. The work then goes on to show that the East and West Coast systems will have different generation mixes and curtailment issues due to the system design and geographic differences between the two regions. The HESA model is then used to look at one east coast Local Education Authority (LEA) area, Angus. The Angus system is studied in 2050 under zero- and high-penetration DER trajectories under a multitude of conditions. Results demonstrate the negative impact to total carbon emissions and cost to consumers that a lack of system reinforcement would have. Analysis also shows that there is real need for local electrical storage units to allow locally generated renewable energy to be utilised in-situ. Finally the multiple energy carrier nature of HESA is used to demonstrate that it is the direct emissions from households from gas-fired heating technologies are the main contributor to total emissions and that it is therefore necessary to invest in research related to lower-carbon heating technologies for the home.

## KEYWORDS

Distributed power generation, Hybrid power systems, Energy Storage, Power distribution, Energy consumption.

*Contact details: elizabeth.robertson@eee.strath.ac.uk

This work is from the Transition Pathways to a Low Carbon Economy consortium supported by the EPSRC and E.ON UK under grant ref.: EP/F022832/1 and the SuperGEN HiDEF project supported by the EPSRC under grant ref GR/T28836/01.

## 1. INTRODUCTION

The energy infrastructure in the UK was originally designed to support 'top down' energy distribution with large scale generation feeding a network of cascading connections leading to a distribution of demand-only customers. However, with increased pressures both internationally and from within the UK's own governmental policy [1] forcing a step change in the way that energy is used and generated the system is having to adapt and adjust continuously to new operating states. Domestic and commercial properties that have historically been demand only are now installing quantities of distributed generation driven by the opportunity to benefit from the income stream offered by Feed In Tariffs (FITs). As domestic load accounts for over 30% of final demand in the UK [2] it is imperative to investigate the potential that the installation of DG in this sector can make to system operation and architecture.

There has already been a significant body of academic research into different aspects of distributed generation and decentralisation of the electricity network [3,4]. Specifically, within current research, micro-generation has largely been treated as aggregated DG or investigations examine sole technology types [5,6]. Also, [6] assesses the control and management of micro wind turbines integrated into a low voltage network whereas [7] differentiates between two micro-technologies (solar PV panels and wind turbines) but deals only with one individual sector (or micro grid) of the energy network.

However, by aggregating micro-technologies or by including only a limited number of technologies, any model will not reflect each individual characteristic, nor can the different costs associated with each technology be accounted for at a more specific level. Similarly, it is important to integrate modelling of the electricity network with other energy carriers such as natural gas to gain a complete picture of the energy system. To date only a limited body of work, such as [8-10], has looked into the interactions of the systems and as such this work includes integrated modelling capability - largely absent from other work in the area - in order to investigate the most accurate representation of the current landscape. As one of the main aims of this work is to optimise the system in terms of cost (an important factor for both consumers and generators), while always ensuring the system remains reliable and secure, it is imperative that a more involved analysis into the impacts of micro-generation is performed.

Consequently, this paper will challenge the current ‘fit-and-forget’ mode of operation of the energy system, as the existing top down topology does not facilitate or maximise the benefits of the bidirectional power flows created by high levels of DERs. DERs include not only distributed generation but, importantly, storage – a significant factor to include when analysing an energy system for the future.

The installation of these new technologies is anticipated to lead to a lesser reliance on large-scale combustion plant. In addition, the combination of micro-generation and storage alongside large scale intermittent renewable generation will create a paradigm shift in system operation, use and loading. This paper will present two models being developed at the University of Strathclyde's Institute of Energy and Environment that are studying the impact that high (DG) penetration levels will have on the energy systems at multiple levels and timescales. Both models have been developed to investigate the impact that an increased deployment of DG will have on network infrastructures and its operation and utilise a hybrid energy approach for modelling a system's network.

A SREN (Scottish Regional ENergy) model has been developed specifically to analyse the impact, at a regional level, of microgeneration facilities installed within domestic properties. The HESA (Hybrid Energy System Analysis) simulation tool has been developed to model multiple energy carriers and their networks simultaneously and allows for a 'whole system' examination. HESA is a multi level model that will be used here to investigate the necessary transportation reinforcements in a system with high penetrations of DERs and calculate the impact that DER deployment will have on the region's emissions levels.

Examination of a future energy system, based of the DECC 2050 Pathways [11] will be employed in this work. The Scottish energy network will be analysed, via a series of comparative case studies, with projected (increased) levels of high DG penetration, decreased levels of consumer demand and reduced reliance upon large scale plant. This paper will begin by describing the analyses and tools used to examine two regions of Scotland through discrete modelling across typical summer and winter days using real weather data to determine an optimal placement of DERs. Secondly this paper describes a summative annual analysis of a local energy system within the east coast of Scotland and will determine the possible outputs levels of the DER in this area as well as the necessary system reinforcements and emissions levels in the area. The paper will then conclude by discussing the impact throughout Scotland of the deployment of DER as well as if, following the DECC 2050 Pathway's, the Scottish governments ambitious emissions and energy targets can be met.

## 2. REGIONAL ANALYSIS

The two case studies that will be considered in this regional analysis are representations of the east and west coasts of Scotland. Each case study consists of 14 energy hubs each representing the DG capabilities of a Local Education Authorities (LEAs) within the region and connections between them. Energy hubs [12] are primarily a mathematical formulation allowing a representation of the conversion of energy from one energy carrier e.g. natural gas through a CHP unit to electricity, heat and carbon emissions. A graphical representation of each system is shown in figures 1a, and c. The West of Scotland system has a high number of connections and generally hubs have links to a number of other hubs with no isolated unconnected hubs present. The East of Scotland however has a very different system design with the cities of Aberdeen and Dundee (hubs 3 and 6) being isolated.

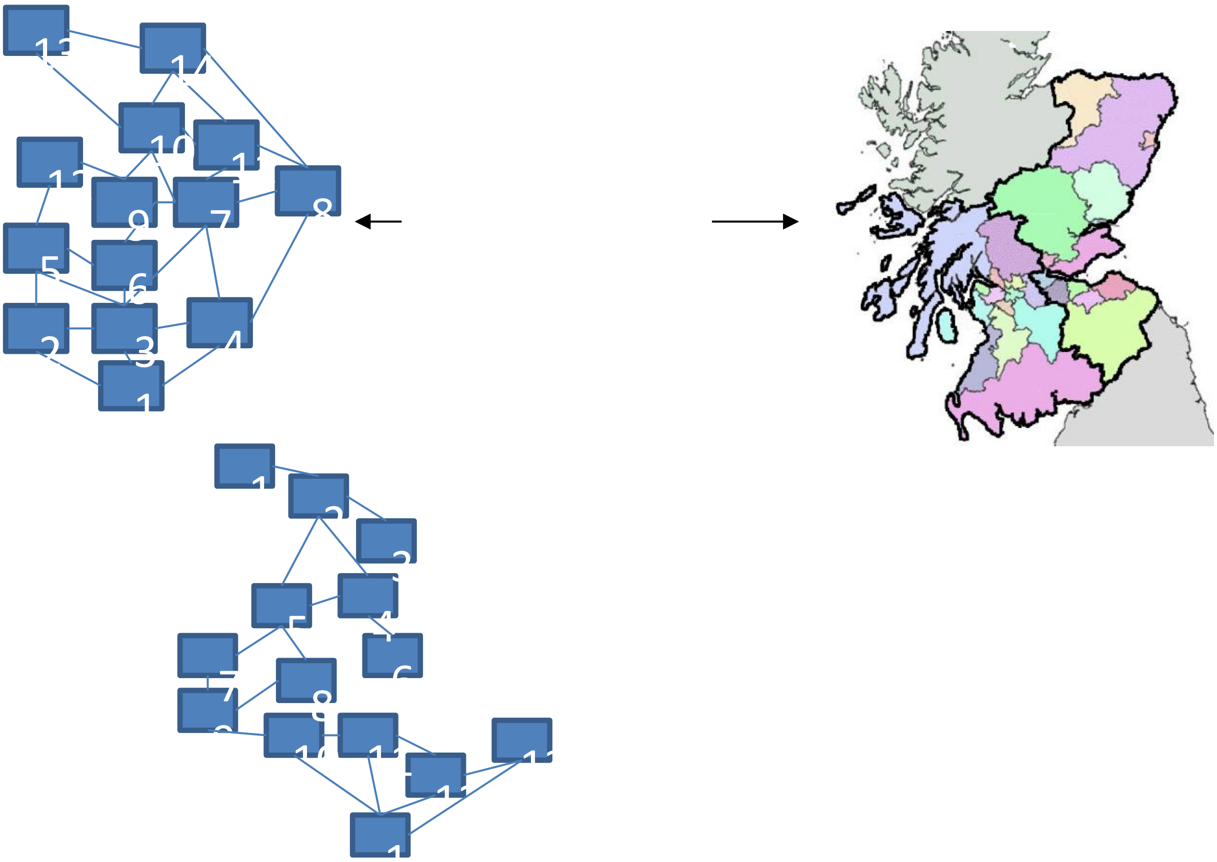


**Figure 1a, 1b and 1c – A map of the West and East of Scotland's LEAs and the relative graphical representation of each system**

Each of the energy hubs representing an LEA in each system above consists of an electricity transformer and micro-generation, namely micro-CHP, PV solar panels and a micro-wind turbine. The aim of the simulations is to find a minimum cost solution for generating the demand level present within a hub. Represented mathematically for hub *j* (contained within set of hubs *H*):

$$\min\ f_j(x) = \sum_{i=1}^{n} Ct_{ij}\, x_{ij} \tag{1}$$

$$x_i \in \Re, \forall j \in H, H = \{h_1, h_2, \ldots, h_{14}\}, \text{such that,} \tag{2}$$

$$Cp_j \begin{bmatrix} x_{1j} \\ x_{2j} \\ x_{3j} \\ x_{4j} \end{bmatrix} - D_j = 0$$

Where:

| | |
|---|---|
| $x_{ij}$ | is the *i*-th energy carrier in hub j |
| $Ct_{ij}$ | is the cost of generation of the *i*-th energy carrier in hub j |
| $Cp_j$ | is the coupling matrix in hub j |
| $D_j$ | is demand in hub j |

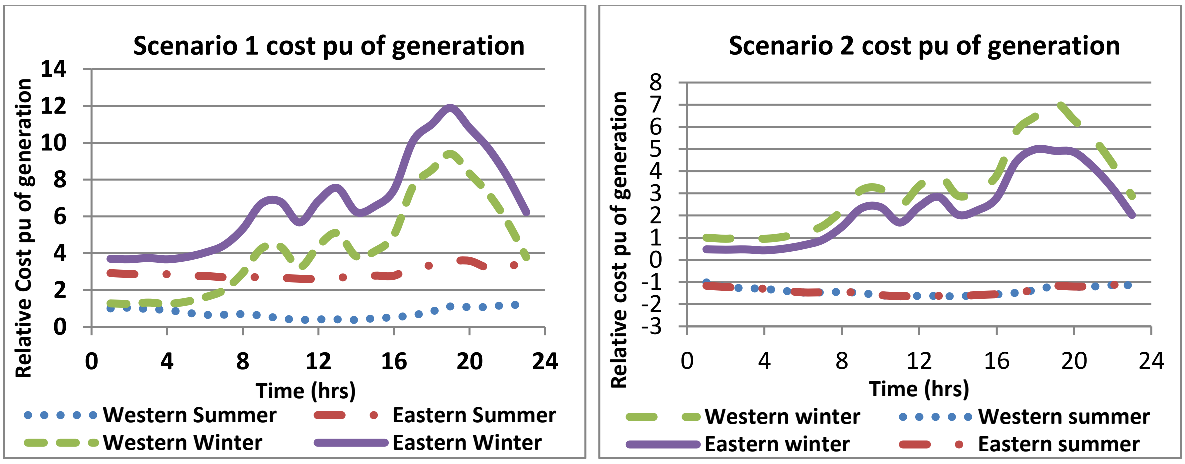
### *2.1 Regional Analysis Results*

Using the two regional case studies of the West and East of Scotland, simulations were carried out for exemplar summer and winter demand days, analysing the extremes of electricity and heat demand. Each case study was considered under two scenarios. The first scenario is representative of Level 1 trajectories across all sectors within the DECC Pathways [11], with demand and energy use following current trends. The second scenario is representative of Level 3 trajectories, where consumers are more aware of their energy use and overall attitudes towards low carbon energy have improved.

Per unit costs for each of the micro-generators, *i*, in hub *j* are calculated as:

$$Cost_{ij} = \frac{I_{ij}}{Output_{ij}} - FIT_{ij}, \tag{3}$$

that is, as a function of initial investment, $I_{ij}$, the expected output across the $i^{th}$ micro-generator's lifespan, $Output$, and associated Feed in Tariff, $FIT_{ij}$ [13].The relative cost of generation across two days calculated by SREN across both scenarios is shown in Figures 2a and 2b.



**Figures 2a (scenario 1) and 2b (scenario 2) – Comparison of relative cost pu of total generation costs against time in Western and Eastern Scotland**

From the above figures it is evident that for scenario 1, the cost of generation in Eastern Scotland is greater - in the winter the cost is 57% more than that of the West. This disparity is explained by the average lower temperatures in the East meaning that in the East heating demand is increased and more devices are switched on. Secondly, due to the nature of the hub layout, flows of electricity are more likely to pass through a greater number of intermediate hubs than in the West which increases the energy transport costs .

In both scenarios 1 and 2 there is a noticeable peak at 1900 hours however there is greater percentage rise in the East than in the West. In the West, the regions of North and South Lanarkshire, and the City of Glasgow all had insufficient micro-generation within their own region around this time. However in the West there are greater opportunities for flows between the interconnected hubs and therefore demand is easily satisfied. Conversely, while Edinburgh, Aberdeen, Aberdeenshire, Fife and Perth and Kinross in the East all experienced an insufficiency in generation from their own DG, with insufficient connections available, in the summer the costs are higher in the East again.

Figure 2b presents the relative costs calculated in scenario 2 and shows that in the winter, energy costs are now higher in Western Scotland. The margin between the east and west is not as large as in scenario 1 but the reversal is significant. With far greater levels of micro-generation in the East, transport costs associated with energy flows are less than in scenario 1 as more electricity is generated locally. The trend of lower costs in scenario 2 is mirrored in the summer but significantly both costs are negative meaning that consumers profit from their distributed generation.

Table I shows the proportion of electricity generated from each source in each of the two case studies during the winter's day in both scenarios. It is clear that while grid electricity is still the significant source of electricity, micro-CHP turbines show great potential in meeting both power and heat demands. Wind turbines also make a significant contribution to demand, particularly in Western Scotland. The main distinction between each scenario is the impact that the micro wind turbines and the solar PV panels have in scenario 2 in terms of contribution to generation.

**Table I - Optimal energy mix during a winter day across the two case studies**

| | **Western Scotland** | | **Eastern Scotland** | |
|---|---|---|---|---|
| | Scenario 1 | Scenario 2 | Scenario 1 | Scenario 2 |
| Grid electricity | 63% | 64% | 69% | 61% |
| Solar PV | 1% | 2% | 0% | 2% |
| Wind Turbine | 9% | 9% | 2% | 10% |
| Micro-CHP | 27% | 24% | 29% | 27% |

Eastern Scotland has experienced a drop in both reliance upon the electricity grid and the micro-CHP units from scenario 1 to scenario 2 which is symbolic of the massive change in costs for this region. Overall, Western Scotland is relatively unchanged in generation mix showing that a hub network with many flows and connections will have a more stabilised energy profile than one with a more linear architecture.

## 3. LOCAL ANALYSIS

The electricity and gas transmission infrastructure within an LEA is as important to consider as that between LEAs (as in the Regional analysis above). The HESA simulation tool will examine the networks within an LEA, more specifically the electricity and gas network connections that couple areas of population (and therefore demand) densities. Using integrated energy system analysis HESA is able to represent the DER and transmission system within a local region in order to perform energy system studies to investigate usage, reinforcement needs, end-user costs and emissions levels.

The energy hub technique is used here to represent the Distributed Generation (DG) and transmission capabilities of a singular population centre. The hub that is used in this analysis contains three generation components (CHP, wind, PV and Solar) as well as transmission capabilities for electricity, natural gas and heat (useful if district heating is to be considered).

The energy hub formulation works alongside a storage module to represent all DERs in a system. Storage modules are used here to represent natural gas stores released in to the system as well as being a proxy for the possibility of electricity being imported from the rest of the system. Storage units are also utilised within the representation of a population centre to represent the natural energy resources that are utilised by the DG and future electrical storage capabilities. Finally, HESA utilising graph theory [14] and network flow programming [15] to solve the transportation problem.

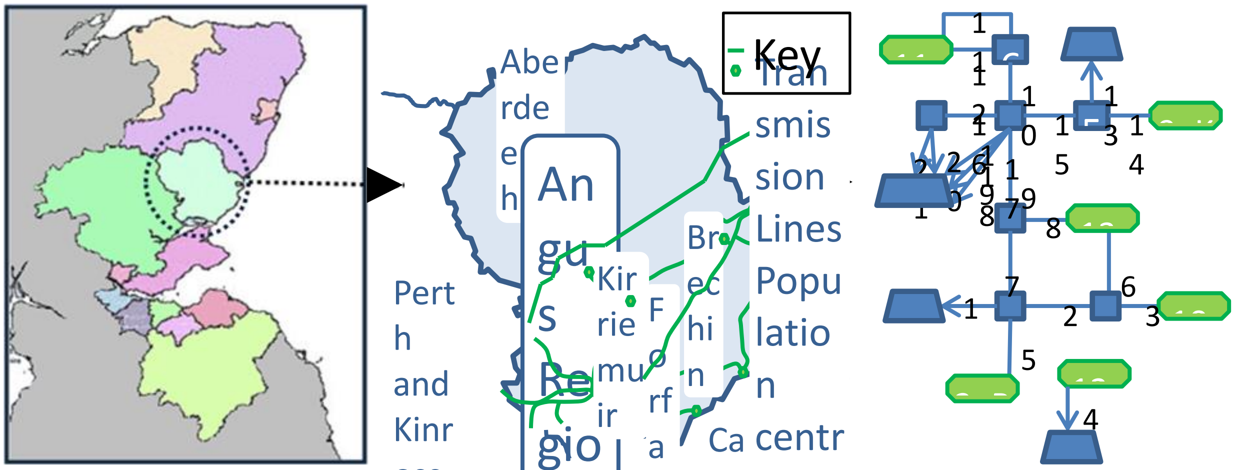


**Figure 3a, b and c - The LEAs i[illegible] ast [illegible] n[illegible] n[illegible] tation of the network and the interaction of load centres within the Ang[illegible] for the [illegible]e of modelling.**

Figure 3a shows the boundaries of each of the [illegible]cal Edu[illegible] Authorities (LEAs) in the East of Scotland where the region of Angus has been hi[illegible]ghted - [illegible]egion that will be studied by HESA in this work. Figure 3b shows Angus's six populat[illegible] centres [illegible] Arbroath, Brechin, Carnoustie, Forfar, Kirriemuir and Montrose and the networks tha[illegible]onnect them other LEAs in the North and South allowing energy to flow through Angus from the North (shown as node 14 in figure 3c) to the South (shown as node 15 in figure 3c). Energy can also be drawn from either node (North or South) to satisfy a demand in Angus as well as the connections allowing excess generation from within Angus to be exported to the rest of the system.

The Angus LEA was studied under conditions similar to that for the regional analysis above following the DECC 2050 Pathways analysis [11] trajectories. Level 1 trajectory sees no DG installed where instead Level 3 sees 5.4m$^2$ of Solar PV and 5kW of micro wind per resident, and 40% of dwellings with CHP units installed.

The results for four simulations (labelled S-1 to S-4) are shown in Table II and are based either on Level 1 or 3 trajectories, with or without a constrained network and under one of two objectives, minimising cost to consumers or CO2 emissions. In all simulations demand was able to be met and a feasible transport solution found. Monetary objective cost was calculated as a function of the costs of energy imported to balance the system, namely natural gas and electricity, and the revenue received by home owners from generation by DG through Feed in Tariffs and Export Tariffs.

**Table II - Angus simulation results with electrical and emissions data**

| *imulation no.* | *S-1* | *S-2* | *S-3* | *S-4* |
|---|---|---|---|---|
| rajectory | Level 1 | Level 3 | Level 3 | Level 3 |
| bjective | £ | £ | kg $CO_2$ | £ |
| etwork constrained | No | No | No | Yes |
| opulation Centre | Yearly Electrical Surplus (MWh) | | | |
| : Brechin | -5,167 | 36,749 | 2,732 | -311 |
| :Kirriemuir | -3,830 | 32,583 | 597 | -1,047 |
| 0: Montrose | -7,634 | 40,193 | 6,177 | 1,734 |
| 1:Forfar | -8,516 | 41,781 | 7,765 | 2,680 |
| 2: Carnoustie | -6,208 | 39,586 | 5,570 | 2,090 |
| 3: Arbroath | -15,114 | 87,289 | 54,979 | 8,513 |
| | Total System Statistics | | | |
| et Electrical Import/Export | Import | Export | Export | Export |
| MWh) | (46,470) | (-278,180) | (-77,820) | (-13,659) |
| missions (kg CO2) | 60,622 | 62,411 | 62,411 | 62,411 |
| pprox. revenue ( per household) | -£662.96 | £2331.27 | £899.03 | £391.55 |

Within Table II, S-1 is the only simulation that is modelled using the level one trajectory profile. This is because with no DER installed in the network there is very little variability in system operation possible. Even when considering different objectives, all energy has to be imported from the other interconnected LEAs and so diversity of results is minimal. With level one trajectory S-1 is a 'businesses as usual' pattern for 2050 and as such is treated as a base for comparison for the rest of the simulations performed. As such, in the case of S-4, the constrained network study, the maximum network capacity was set to the S-1 network capacity (+10%) as the investment necessary for S-1 would take place even without DER deployment thus that network is taken as the benchmark.

Comparing the electrical surplus results for the population centres in the Angus region between S-4 and S-2 (the constrained and unconstrained simulations) in which both have cost as an objective function sees that a constrained network, although still allowing all demand to be met my electricity from DER sources, DER is highly under-utilised. Even utilising the availability of local electrical storage units the output from DG is curtailed meaning that total electrical export from the constrained system in S-4 is less than 5% of that in S-2 and the financial revenue is less than half that in S-2. This means that a constrained network and lack of financial investment beyond a 'business as usual' case will prevent the full utilisation of DER and the economic benefits that they can bring.

In an unconstrained network simulation when there is no financial force and instead minimising emissions is the objective, as in S-3, there is nothing to compel production of more generation than is necessary. Therefore there in S-3 there is a much smaller amount DG capacity used than in S-2, reducing the impact on the network. S-3 also sees no use of carbon-intensive grid electricity as in S-4, which although creates Angus as net exporter, still uses grid energy to support the system which the Angus in S-3 does not. Total emissions levels as an objective therefore creates a very different picture of Angus that when considering monetary gain, however as can be seen in Table II emissions levels are consistent throughout the four simulations.

The emissions levels are constant across the level three trajectory simulations as all emissions in S-2 to S-4 are coming from the same source - heat generation by way of gas fired CHP and more conventional boilers. To reduce these emissions efficient and renewable (zero carbon) technologies must be found to heat domestic dwellings. Biomass is a low carbon option but research shows that there are many challenges in with regard to limited space and suitability of crops for growth [16] as well the 'low carbon' title given to biomass being challenged [17]. Additionally, in order to minimise carbon intensity if the electricity used in homes it is essential that the most is made of the zero-direct-emissions electricity from domestically installed DG. In modelling S-2 to S-4 all contained the capability to store electric locally hence the ability to stay 'off grid'. It is therefore essential that research into affordable storage units for a local scale are given financial backing allowing carbon free energy from DG being produces locally can be stored and then used when natural resources are not available (i.e. a calm night when neither wind or solar generation can generate). Local electrical storage as well as an increased capacity in the networks is therefore essential in challenge of minimising emissions from dwellings as well as generating maximum income from DG.

## 4. CONCLUSIONS

This paper has described a SREN model using a method by which detailed modelling of local energy networks with multiple energy carriers can be utilised in novel analyses of generation and demand. Multiple micro-technologies have been modelled in isolation, as part of a discrete system, to solve an economic dispatch problem at a regional level using the energy hub concept. This approach has been demonstrated using an initial east/west comparison across regional Scotland, an inter-area regional formulation that hasn't been studied sufficiently in previous literature.

The initial results presented in this paper under two DECC derived scenarios have, in one case, shown Western Scotland to have lower generation costs than Eastern Scotland, signifying the impact on overall cost of generation that a highly decentralised network with many connecting flows can have. As the number of installations increase however, more energy can be produced locally and it has been shown that the greater impact in cost reduction will be experienced in more linear hub topologies, in this case Eastern Scotland.

One important issue to be highlighted is that of FITs. They are not scheduled to be paid indefinitely and this analysis shows how unfeasible the current FIT system is in the long term if high levels of DERs are to be integrated into the grid. Consequently, the policies of central and/or local government will be fundamental in achieving a decentralised energy network that is sustainable both in terms of energy sources and costs. They will have to work hard to ensure consumers are encouraged to not only be proactive in installing their own local generation but to change their energy use behaviour as well if the country is to meet tough energy targets.

The HESA tool was then used to represent the integrated energy system of Angus, a LEA in the East Coast of Scotland. A model was created that included the six major population centres in Angus and the transmission system that connects them. Four studies were performed on the system for the year 2050 with corresponding demand levels from the DECC 2050 Pathways. The studies showed that that in order to minimise the curtailment of DG and maximise the utilisation of energy generated locally it was essential that DG penetration is included in future network plans.

Simulations demonstrated that building a network without the consideration for the added capacity needed by DG total system exports were only 17.5% of a case with sufficient network capacity and that household revenue was curtailed to only 5% of the maximum ability. It was also demonstrated that alongside a need for local energy storage to 'flatten out' the variability in DG generation patterns allowing locally generated energy to be stored and then consumed locally it is necessary to find new heating technologies. Emissions from natural gas fired heating systems were the main contributor to emissions in Angus and as such it is important that technologies such as biomass fired heating units are considered, although as with most new technologies biomass fired heating has problems.

The results from the SREN show that on a winter day approximately 65% of electricity must come from the grid and therefore large scale generation. SREN does not consider electrical storage however and results from HESA demonstrated that if local electrical storage was available LEAs could become electrically self sufficient. This will mean that although DG in Scotland will form a significant part of the solution, storage is needed to reach the 100% renewable energy target. In the interim electricity will still have to come from the grid and therefore it is essential that if Scottish Government targets are to be met there is support for DG and local storage solutions alongside the decarbonisation of grid electricity and large scale low-emission plant such as nuclear, wind, tidal, solar etc.

This paper has investigated the feasibility of high penetrations of DG in the energy system in Scotland, as well as the advantages storage facilities may bestow upon it. Results have demonstrated the influence that the change in system use will have on regional and local emission levels and the final costs to consumers. Results have also demonstrated the need for reinforcements to the system. Further work in this area would be to include the use of storage technologies in a SREN model as well as HESA to make the results fully compatible. Work may then be carried out such that the models could feed information from to each other and thus strengthen the results found.

## BIBLIOGRAPHY

[1] Ofgem. Renewables Obligation: Annual Report 2008-2009, 2010. http://www.ofgem.gov.uk

[2] DECC. Digest of United Kingdom Energy Statistics 2011. http://www.decc.gov.uk/assets/decc/11/stats/publications/dukes

[3] Emhemed, A.S.; Burt, G.; Anaya-Lara, O. Impact of high penetration of single-phase distributed energy resources on the protection of LV distribution networks. UPEC 2007, 4-6 Sept. 2007

[4] Alarcon-Rodriguez, A.; Haesen, E.; Ault, G.; Driesen, J.; Belmans, R. Multi-objective planning framework for stochastic and controllable distributed energy resources. Renewable Power Generation, IET, vol.3, no.2, pp.227-238, June 2009

[5] Thomson, M.; Infield, D.G.; "Impact of widespread photovoltaics generation on distribution systems," Renewable Power Generation, IET , vol.1, no.1, pp.33-40, March 2007

[6] Calderaro, V.; Coppola, V.; Galdi, V.; Siano, P. Assessing control and management issues for micro wind generation integration into microgrids. MELECON 2008. 5-7 May 2008

[7] Kuzle, I.; Zdrilic, M.; Pandzic, H. Virtual power plant dispatch optimization using linear programming. Environment and Electrical Engineering (EEEIC), 2011, pp.1-4, 8-11 May 2011

[8] Favre-Perrod, P. A vision of future energy networks. in Power Engineering Society Inaugural Conference and Exposition in Africa, 2005 IEEE. 2005.
[9] Carradore, L. and F. Bignucolo. Distributed multi-generation and application of the energy hub concept in future networks. UPEC 2008. 43rd International. 2008.
[10] Shahidehpour, M., Y. Fu, and T. Wiedman, Impact of Natural Gas Infrastructure on Electric Power Systems. Proceedings of the IEEE, 2005. **93**(5): p. 1042-1056.
[11] DECC, 2050 Pathways analysis. Available at http://www.decc.gov.uk
[12] Geidl, M. and G. Andersson, Optimal Power Flow of Multiple Energy Carriers. Power Systems, IEEE Transactions on, 2007. **22**(1): p. 145-155.
[13] Feed-In-Tariffs, Historical, http://www.fitariffs.co.uk/eligible/levels/history/
[14] A. Quelhas, et al., A Multiperiod Generalized Network Flow Model of the U.S. Integrated Energy System: Part I-Model Description. Power Systems, IEEE Transactions on, 2007. 22(2): p. 829-836.
[15] J.W. Chinneck, Practical optimization: a Gentle Introduction, 2001, Electronic Doc.: http://www.sce.carleton.ca/faculty/chinneck/po.html
[16] Sherrington, C., J. Bartley, and D. Moran, Farm-level constraints on the domestic supply of perennial energy crops in the UK. Energy Policy, 2008. **36**(7): p. 2504-2512.
[17] Fargione, J., et al., Land Clearing and the Biofuel Carbon Debt. Science, 2008. **319**(5867): p. 1235-1238.