RENEWABLE
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Loco2gen

Solar Feasibility Study

RCEF funded study

Marshfield Community Land Trust

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Executive Summary

Marshfield Community Land Trust (MCLT) have ambitions to offset the total energy consumption of the village of Marshfield with renewable energy generation. This equates to c. 2.9GWh of electricity, and the intention therefore is to install c. 5MW of solar PV near to the village. MCLT have set up an Energy Working Group to investigate and promote energy saving and energy generation opportunities within the community. Locogen have been appointed to support MCLT in the investigation on the feasibility of a prospective solar farm from the perspectives of planning, grid connection and financial viability.

MCLT provided Locogen with two potential land areas sufficient in scale for developing >1MW of solar PV: Rushmead Farm and Tilley Field. The former is suitable for a large-scale project (up to c. 20MW), whereas the latter is sufficient for a small scale project, should this be more financially viable than the 5MW project. Both sites are presented in Section 1 of this document.

Section 2 sets out a detailed planning and technical constraints assessment, looking into all aspects of a solar development that are likely to be addressed in planning. As anticipated, the core risk in planning for this project is the site's situation within the Cotswolds AONB. However, given the community interest and the site's relative position within the designated area, this is conclusively a challenge, but not a showstopper.

Section 3 outlines the options for grid connection. This is a key challenge in the project, due to its rural locality. However, Locogen found that the site's position near to two alternative DNO 'regions' provided opportunity for alternative grid connection options, whereas the local grid in WPD Midlands region is highly constrained. This ultimately proved that there is most capacity (and also the most feasible connection route) available to the South (WPD Southwest reigon) near to Bath, and should the PV project be combined with another known renewables development, a shared grid connection would be mutually beneficial.

Section 4 presents an outline specification for the preferred option, including detail on technology options, and an indicative layout for the site. Further to this, Locogen have provided the Client with a pre-application advice package, including the layout alongside a suite of constraints mapping drawings and supporting document.

Detailed financial modelling proved the 5MW project with a shared grid connection is the most financially viable project, and the only project with sufficient returns to be attractive to external investors. It is noted that the costs used are considered 'realistic', with cost tolerances provided in Appendix A. Subsequent appendices outline various funding opportunities and community organisation operational models which may be applicable to the project. At the Client's request, detailed appendices regarding revenue streams and battery storage have also been included, alongside a selection of case studies.

It is concluded that the 5MW project with a shared grid connection is the most financially attractive option, but also is not without significant risk. Should the parallel development project not go ahead, it may be worthwhile progressing a larger solar project, perhaps in partnership with another developer, to share on the grid connection cost. Furthermore, a larger project is likely to also provide more attractive energy storage (battery) opportunities.

Ultimately, if the MCLT solar development were to progress, it would be exemplar in demonstrating how communities can overcome planning challenges and develop sizeable renewable projects, substantially contributing to climate change targets and demonstrating that renewables can be developed in a subsidy free environment. The project could demonstrate that, if sited discretely, nationally important landscapes such as the AONB can accommodate small-medium renewable generation projects that are of significant benefit to the local community and ultimately improves the environment. The project would also importantly be an excellent example of how communities can collaborate with third party organisations to develop renewable energy projects.

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1. Background

1.1. Context

The Marshfield Community Land Trust ('MCLT' or 'The Client') is a Community Benefit Society, operating local to the village of Marshfield, north of Bath. The Energy Working Group (EWG) within MCLT have a mission to "help the community of Marshfield make contributions to the sustainability of our environment, and enable our community to reduce the costs paid for energy over time." They are tackling this mission head-on with a large-scale, ground-mounted solar development, intended to offset the entire electricity demand of the village, including for an anticipated increase in demand due to future uptake of electric vehicles and electrically-powered heating.

MCLT commissioned Locogen to conduct a detailed feasibility study, assessing whether a 5MW ground-mounted solar scheme could be financially viable, with emphasis on the challenges presented by both planning and grid.

There are four substations in the village of Marshfield, and a recent investigation estimated that c. 2.9GWh of electricity was consumed annually. Taking into account future additional demands from electric vehicle charging and infiltration of electrically-powered renewable heating, MCLT estimate this will increase significantly. Ultimately, MCLT aim to match this future demand with local renewable generation, thus having net zero emissions from electricity across the village. The project is therefore estimated to be in the region of 5MW, although the identified land options have sufficient space for more than 50MW.

1.2. Site locations

Two potential locations for the project have already been identified by MCLT, and they have also already engaged with the land-owners. The available land parcels are illustrated in Figure 1 below; the background and current status of each is outlined subsequently.

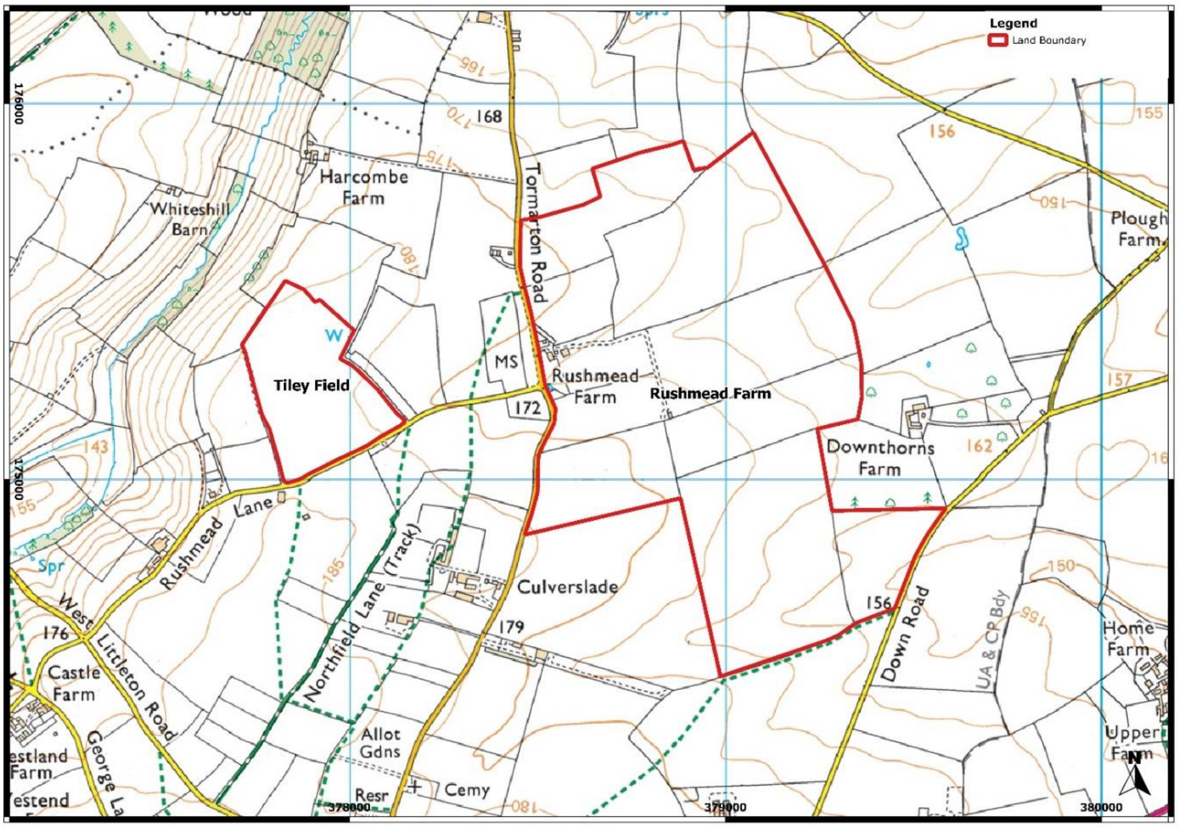

Figure 1: Rushmead Farm and Tiley Field Land Boundaries

Rushmead Farm

The area available at Rushmead Farm is c. 92.2 Ha/ 227.8 acres. This is currently in ownership of South Gloucestershire Council and has an agricultural tenancy.

Locogen are aware of a renewable energy project currently being investigated by the Council which may utilise the land at Rushmead Farm. However, in discussions with the West of England Combined Authority, it was agreed that the land could be shared between these projects. Similarly, if both projects were to proceed, the grid connection could also be shared providing significant savings to both parties. This is discussed in detail throughout the report.

Tiley Field

The area available at the Tiley Field is c. 12.6 Ha/ 31.2 acres. This is privately owned, and is used for grazing cattle and/or silage hay crops. This field would require a rent to be paid and secured for a minimum of 25 years.

1.3. Objectives

In order to achieve the aims of the Client and to determine the feasibility of the solar PV project, three key objectives have been defined as follows:

1. Assess the technical feasibility of the project, with focus on planning and grid availability;
2. Review the agreements required, and models for ownership and governance; and
3. Conduct detailed financial, risk, and opportunity evaluations.

Essentially, this will demonstrate whether the annual PV generation can viably meet the annual electrical demand of the community, with a net positive impact.

2. Constraints Assessment

2.1. Planning Constraints

2.1.1. Planning Policy

National Planning Policy Framework (NPPF)

The revised National Planning Policy Framework (2021) sets out the Government's planning policies. The Framework states, regarding renewable development that:

> *"The planning system should support the transition to a low carbon future in a changing climate, taking full account of flood risk and coastal change. It should help to: shape places in ways that contribute to radical reductions in greenhouse gas emissions, minimise vulnerability and improve resilience; encourage the reuse of existing resources, including the conversion of existing buildings; and support renewable and low carbon energy and associated infrastructure."*

The proposed development benefits from being a community-led project as the NPPF states that:

> *"Local planning authorities should support community-led initiatives for renewable and low carbon energy, including developments outside areas identified in local plans or other strategic policies that are being taken forward through neighbourhood planning."*

However, the proposed development location is also within the Costwolds Areas of Outstanding Natural Beauty (AONB), discussed in more detail Section 2.1.4. NPPF is opposed to any major developments located in protected landscapes:

> *"When considering applications for development within National Parks, the Broads and Areas of Outstanding Natural Beauty, permission should be refused for major development other than in exceptional circumstances, and where it can be demonstrated that the development is in the public interest. Consideration of such applications should include an assessment of:*
>
> *a) the need for the development, including in terms of any national considerations, and the impact of permitting it, or refusing it, upon the local economy;*
>
> *b) the cost of, and scope for, developing outside the designated area, or meeting the need for it in some other way; and*
>
> *c) any detrimental effect on the environment, the landscape and recreational opportunities, and the extent to which that could be moderated."*

While this could be a significant barrier to development, the Marshfield project has the benefit of being community led, making the location vital in its connection to the community and demonstrating that the development is "*in the public interest*". Furthermore, at 5MW (or less) the project may not be considered a 'major' development, and this definition should in the first instance be queried with the LPA. As Marshfield and its surroundings are all within the AONB, relocating the project is not an option. The project should therefore seek to to absolutely minimise impact on the AONB's setting and any associated recreational/landscape opportunities.

Local Development Plan

South Gloucestershire Council (SGC) are generally supportive of proposals for the generation of energy from renewable sources, provided that the installation would not cause significant demonstratable harm to residential amenity, individually or cumulatively. The South Gloucestershire Local Plan Core Strategy (2013) states:

> *"In assessing proposals significant weight will be given to:*

- *The wider environmental benefits associated with increased production of energy from renewable sources*
- *Proposals that enjoy significant community support and generate an income for community infrastructure purposes by selling heat or electricity to the National Grid*
- *The time limited, non-permanent nature of some types of installations; and*
- *The need for secure and reliable energy generation capacity, job creation opportunities and local economic benefits*"

The council states that they will not support renewable energy proposals which are located in areas covered by national designations and areas of local landscape value unless they do not individually or cumulatively compromise the objectives of the designations especially with regard to landscape character, visual impact and residential amenity. However, they are supportive of development proposals that will benefit the local community. The South Gloucestershire Local Plan Core Strategy (2013) states:

> *"With regard to criterion 2, installations that would generate a direct financial benefit to the local community will be encouraged. This can be achieved by legal agreement that guarantees to pay a percentage of the income generated by selling heat or electricity to the grid, into a Community Trust Fund, or other suitable mechanism, controlled by the local community for spending on other local infrastructure and energy efficiency initiatives. This approach is particularly promoted in the Area of Outstanding Natural Beauty (AONB), in order to support local communities and the objectives of the AONB Management Plan."*

SGC's Climate Emergency Status

Furthermore, in July 2019 South Gloucestershire Council declared a climate emergency. In their Climate Emergency Strategy (2020) they state:

> *"In addition, the council joined a group of forward thinking local authorities and signed up to the UK100 pledge to enable our communities to achieve 100% renewable energy across all sectors. The revised UK100 pledge (signed November 2020) commits to net zero council emissions by 2030 and net zero area-wide emissions by 2045*."

This highlights SGCs support for community renewable projects.

2.1.2. Local solar planning history

The Marshfield site itself has no planning history regarding solar development at the site.

South Gloucestershire Council (SGC) have supported several solar projects within the local authority area, although none are within the AONB. The majority of operational solar developments are located in the suburbs of Bristol and Yate, which include 7 operational ground-mounted solar projects with a total capacity of 80MW. A 50MW solar farm has also been consented near to Tytherington.

The nearest operational site within South Gloucestershire Local Authority is at Ring O Bells Farm, east of Pucklechurch, of 5MW capacity. The nearest operational solar farm outside of South Gloucestershire local Authority area is Castle Combe Circuit located c. 6km to the east, in Wiltshire Local Authority Area.

A review of current applications was carried out. It appears that there have been no ground-mounted solar planning applications in Marshfield Parish in the past 10 years (one withdrawn application in 2011). Therefore, a wider review of the Boyd Valley ward (in which the site is situated) and the Chipping Norton & Cotswold Edge ward, which also contains areas of the AONB, was carried out. This indicated that there are several applications for ground-mounted solar developments in the Boyd Valley ward, namely:

- P20/09237/F, Thatched Cottage, Hydes Lane, Cold Ashton, SN14 8JU. This project was for only 24 solar panels adjacent to a residential property and was approved.

- PK17/4613/F, Bottoms Farm Cottage, Doynton, BS30 5T. This project was also for only 24 solar panels and was approved.
- PK14/3347/F, Hamswell Farm, Freezing Hill Lane, Cold Ashton, BA1 9DG. This project was an installation of a 10kW solar array and was approved.

These projects are all comparatively small-scale when compared with the Marshfield project, and appear to focus on offsetting on-site loads. To achieve the scale required to offset the community's demand, a significantly larger array is required.

There was only one ground mounted solar development currently going through planning in the Chipping Norton & Cotswold edge council ward:

- P20/24180/F, Newlands Farm, Rag Lane, GL12 8LD (c. 15km northwest of Marshfield). In screening (P19/027/SCR), it was deemed than an EIA is not required for this 49.99MW project. The planning application is awaiting decision.

2.1.3. Land Classification

Agricultural Land Classification (ALC) is a system used in England and Wales to classify agricultural land according to versatility and suitability for growing. A combination of climate, topography and soil characteristics and their unique interaction determines the limitation and grade of the land. The ALC is used to help inform decisions on the appropriate sustainable development of land.

Natural England's 'Guide to assessing development proposals on agricultural land' states that:

> *"Developers and local planning authorities (LPAs) should refer to the following government policies and legislation when considering development proposals that affect agricultural land and soils. They aim to protect:*
>
> - *the best and most versatile (BMV) agricultural land from significant, inappropriate or unsustainable development proposals*
> - *all soils by managing them in a sustainable way"*

The best and most versatile agricultural land is defined as land in Grades 1, 2 and 3a. Planning authorities must consult Natural England on all non-agricultural applications that result in the loss of more than 20 hectares (ha) of BMV land if the land is not included in a development plan.

The maps below indicate that both the Rushmead and Tiley Field sites are located on Grade 3 land. However, it is not detailed whether this constitutes as Grade 3a or 3b. The likelihood of the site being ALC 3a is relatively low, based on the distance to the nearest Class 2 areas vs Class 4 areas.

A more detailed Agricultural Land Classification survey will be required during planning to quantify soil composition and the metrics used to classify farmland quality. Should the land be decidedly ALC 3a, the planning risk is increased and MCLT would need to demonstrate there is no alternative site of suitable scale. This is not considered a significant risk.

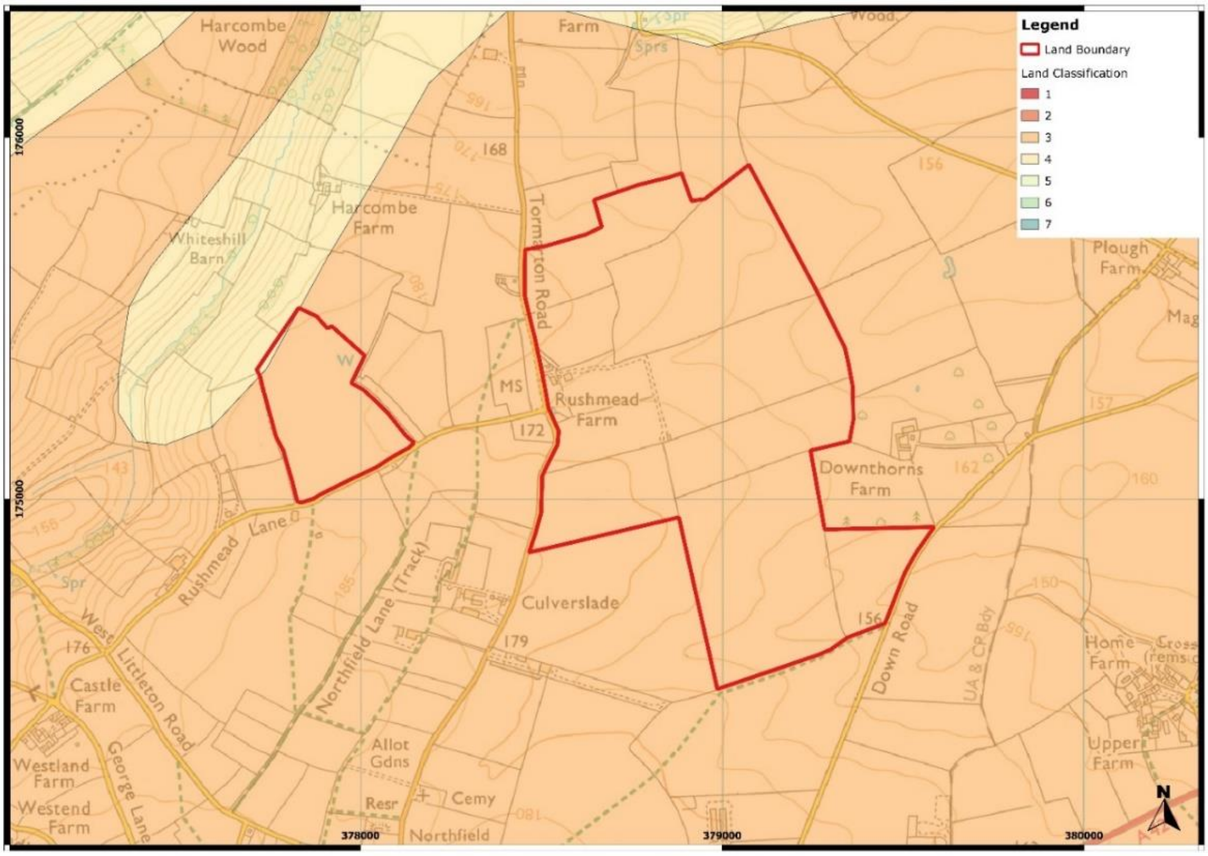

Figure 2: Agricultural Land Classification

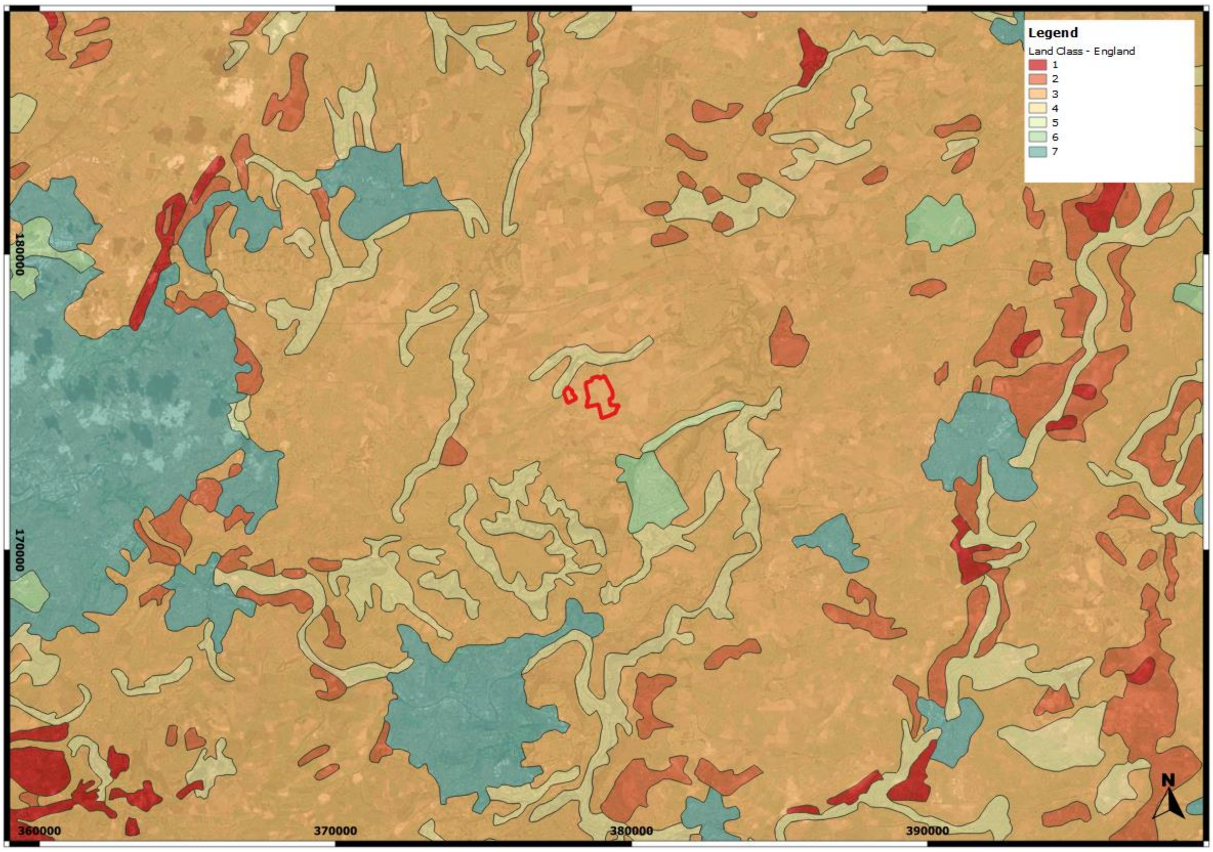

Figure 3: Agricultural Land Classification - wider context

2.1.4. Environmental and Ecological Designations

Cotswolds Area of Outstanding Natural Beauty

Areas of Outstanding Natural Beauty (AONBs) are areas of the countryside that have a rich diversity of landscapes and are of great value nationally. The main purposes of the AONB designation is to conserve and enhance the natural beauty of the landscape; to meet the need for quiet enjoyment of the countryside, and to have regard for the interests of those who live and work there.

Both the Rushmead Farm site and the Tiley Field Site are located within the lower branch of the Cotswold AONB, the largest AONB in England, between Castle Comb and Bath. The site's location within the AONB is illustrated in Figure 10. The Costswolds AONB Landscape Character assessment shows the site in character area 11a: South and Mid Cotswolds lowlands, with the west of Tormarton road in character are 9d: Cotswolds High Wold Dip Slope.

With regards to protection of the AONB, SGC states that:

> *"Development control decisions will favour the conservation and enhancement of the natural beauty of the landscape, although regard will also be given to the economic and social wellbeing of the AONB."*

Which suggests that, given the community interest and benefits from the project, there may be argument for a solar development despite the AONB designation.

Consultation with the Cotswolds Conservation Board will also be required. The Cotswolds Conservation Board is the only organisation to look after the AONB as a whole. In the Board's Position Statement on Renewable Energy (2014), they highlight that:

> *"If a more substantial free-standing solar array proposal (a solar farm) were to be submitted (above 1 hectare for example) the Board considers that paragraph 116 of the NPPF would apply as this would be a major development. If such schemes are submitted on the basis of exceptional circumstances then the Board would adopt a criterion-based approach following the principles outlined in the NPPF (paragraph 116). It is extremely unlikely that any location could be found within the AONB or its setting where such large solar farms would not have a significant adverse impact on the landscape, sense of remoteness, tranquility, natural beauty and landscape character for which the AONB is valued. The Board considers that such installations would directly conflict with the purpose of designation."*

However, in the AONB Management Plan (2018), Policy CC7 on Climate Change Mitigation states that the AONB will aim to reduce GHG emissions through a range of measures, including:

> *"using small-scale forms of renewable energy that are compatible with the purpose of AONB designation… Measures to mitigate the impacts of climate change include the provision of renewable energy, for example, through solar farms… Any such renewable energy schemes need to be carefully sited and managed to avoid any adverse impacts on the natural beauty of the AONB."*

Ultimately, while the position statement does not support the project, more recent publications seek urgent solutions to the climate crisis, and therefore this project should be addressed with the board as a comparatively small project with strong ties to the local community.

Other designated sites

2km south-west of the Rushmead Farm site and 1.9km south-west of the Tiley Field site is St. Catherine's Valley SSSI which is protected for its steep sided valley habitat systems and grasslands which have a limited distribution in the UK. Impact Risk Zones (IRZs) are a GIS tool developed by Natural England to make a rapid initial assessment of the potential risks to SSSIs posed by development proposals. These were created to aid Local Authorities in assessing whether a proposed development is likely to affect a SSSI (when not within the designation boundary) and choose whether to seek advice from Natural England. According to the SSSI IRZ dataset, the proposed development is unlikely to pose a risk to these SSSI's.

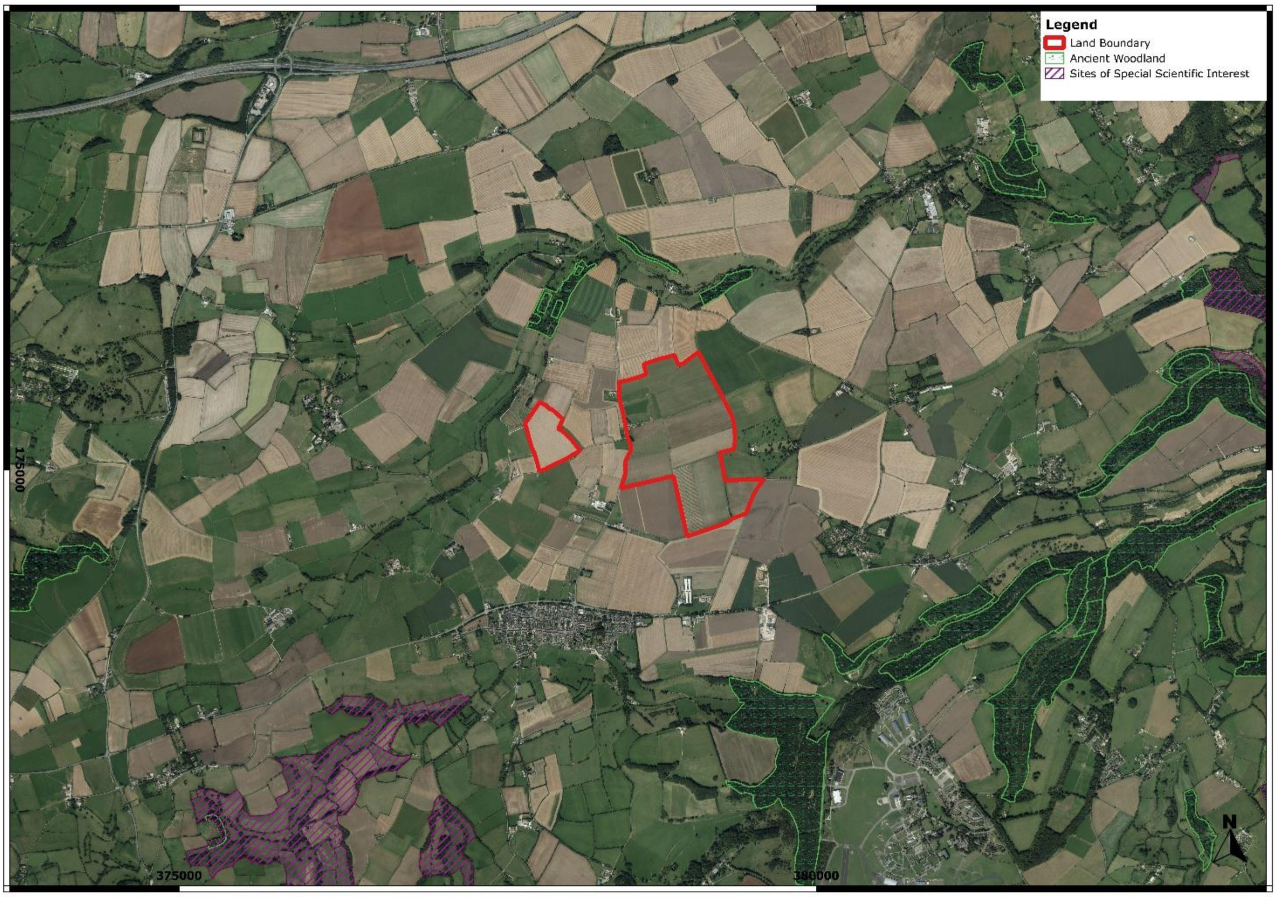

Figure 4: Environmental Designations

2.1.5. Hydrology, Geology & Hydrogeology

There are no watercourses running through or close to either the Rushmead Farm site or the Tiley Field site. There is a small, seasonal pool next to the Rushmead Farm Buildings and adjacent to Tormaton Road, indicated on the OS map. The nearest significant waterway (and associated flood alert area) is Broadmead Brook, 1.5km to the east. According to Environment Agency data, both sites are located in Flood Zone 1 which has a low probability of flooding. The Environmental Agency states that a flood risk assessment is required when proposed developments are:

- in flood zone 2 or 3 including minor development and change of use
- more than 1 hectare (ha) in flood zone 1
- less than 1 ha in flood zone 1, including a change of use in development type to a more vulnerable class (for example from commercial to residential), where they could be affected by sources of flooding other than rivers and the sea (for example surface water drains, reservoirs)
- in an area within flood zone 1 which has critical drainage problems as notified by the Environment Agency

The proposed development size will be larger than 1 hectare and located in Flood Zone 1 therefore, a flood risk assessment will still be required even though the probability of risk is low.

2.1.6. Cultural heritage

There are no cultural heritage designations located within the sites. There are, however, multiple designations located within 1km. There are 14 listed buildings, which are all classed as Grade II. All of these buildings are well screened from both sites by the existing woodland except from Downthorn's Farmhouse (158m east), which may be visible to the Rushmead Farm site (though unlikely from the proposed development area).

Within 3km of the site there are an additional six Scheduled Ancient Monuments, with the closest being 'Bowl barrow, 420m north of Down Farm' located 1.8km north of the Marshfield site. Additionally, there are two designated Parks and gardens within 3km: Ashwicke Hall, located 1.2km South of the Rushmead Farm site and Dyrham Park, located 2.8km west of Tiley Field site.

The town of Marshfield, 730m south-west, is designated as a Conservation Area. Conservation areas are protected by the council for their special architectural and/or historic interest, which deserves careful management to protect their character. The purpose of a conservation area is not to prevent any development but rather to enable its careful management.

It is important that the setting of these historical assets is considered, and as such Historic England may object to local modern developments such as solar farm developments if they are considered to have a significant impact on the setting of these locations.

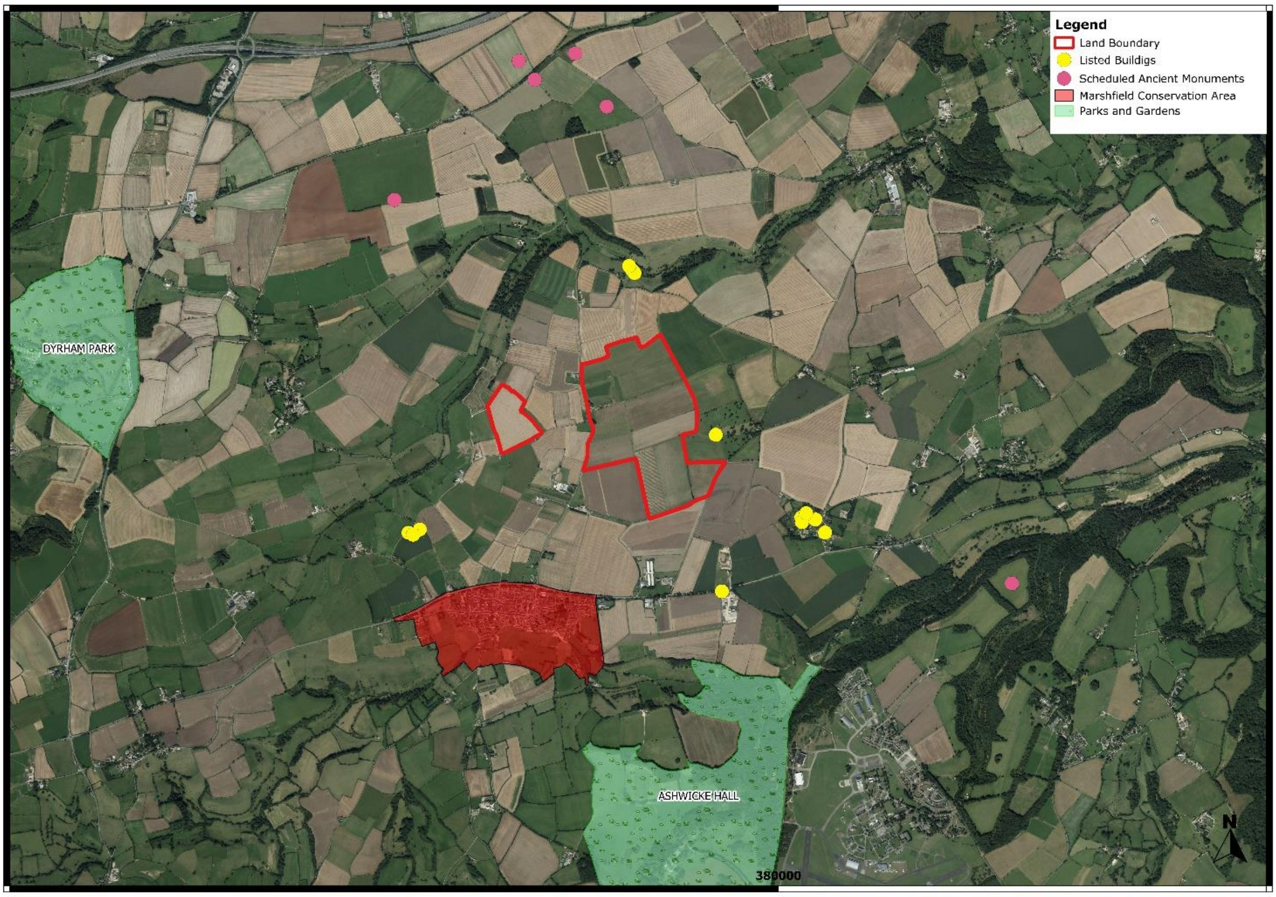

Figure 5: Cultural heritage designations

2.1.7. Visual Impact

Locogen have proposed a development footprint at the Rushmead Farm site (detailed in Section 4.2). This location is prioritised due to it's limited visibility to nearby receptors out with the site itself. Given the relatively low heights of the development (maximum of 3.5m), topography and intervening vegetation would provide screening to nearby roads, footpaths and properties. This screening will be provided by existing hedgerow and further improved by thickening of hedgerow and tree planting completed as part of the ecological enhancement measures. Ultimately there would be some physical changes within the development site, but it is anticipated that the surrounding area would remain for the most part unchanged. The potential for visibility from further viewpoints (due to varied terrain, likey to the west) should be confirmed by a detailed landscape and visual impact assessment (LVIA).

The Tiley Field is elevated and has very little existing screening. It is likely to be visible from the adjacent road, and from nearby residential receptors.

Public areas are sensitive visual receptors however, there are no public congregating areas near or adjacent to the proposed development area. There are no Public Rights of Way (PROWs) that pass through either land boundary. However, there may be visual impacts on nearby PROWs, including those to the immediate south of Rushmead Farm, and the two south of Tiley Field. Figure 6 below illustrates the nearby public footpaths.

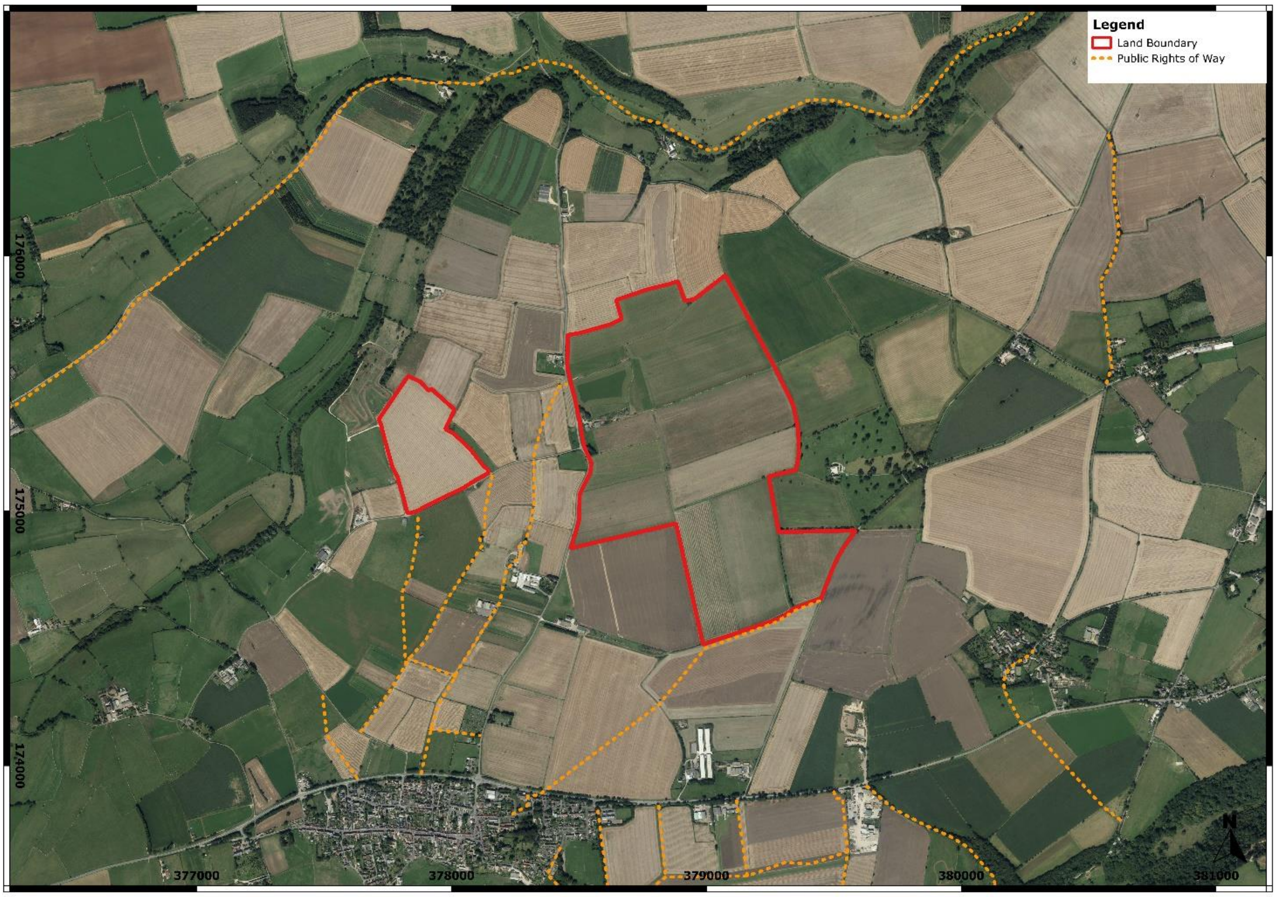

Figure 6: Public Rights of Way

2.1.8. Glint and glare

Solar glint and glare refers to the unwanted reflection of the sun's rays by the face of a reflective surface, which can affect safety of transport, and can also affect residents in neighbouring areas. These risks have also been assessed:

Residential

There are 103 residential properties within 1km of the site. Four of these properties are located directly to the west and east of both sites and therefore theoretically could have a risk of glint and glare when the sun is rising in the east and setting in the west (Figure 7). An initial walkover of the site examined the visibility from nearby dwellings, with the following observations:

- Property A has visibility of the Tiley Field, but very limited visibility of Rushmead Farm development area. It's location to the north of both sites means that the likelihood of glint and glare is very unlikely, and decreasingly likely if the panels are to be orientated south.
- Properties B and C are both surrounded by woodland and therefore should not be impacted by glint and glare, provided screening remains in place and is of sufficient height (to be confirmed by assessment).
- Property D is within the Rushmead Farm land boundary and is currently tenanted. The landowner will need to consult on the project with the Tenant, and may wish to offer the tenant a financial incentive, at cost to the developers.

All other residential properties appear to be well screened from both sites. A glint and glare assessment may be required, if necessary, to estimate the full impact of the proposed development site.

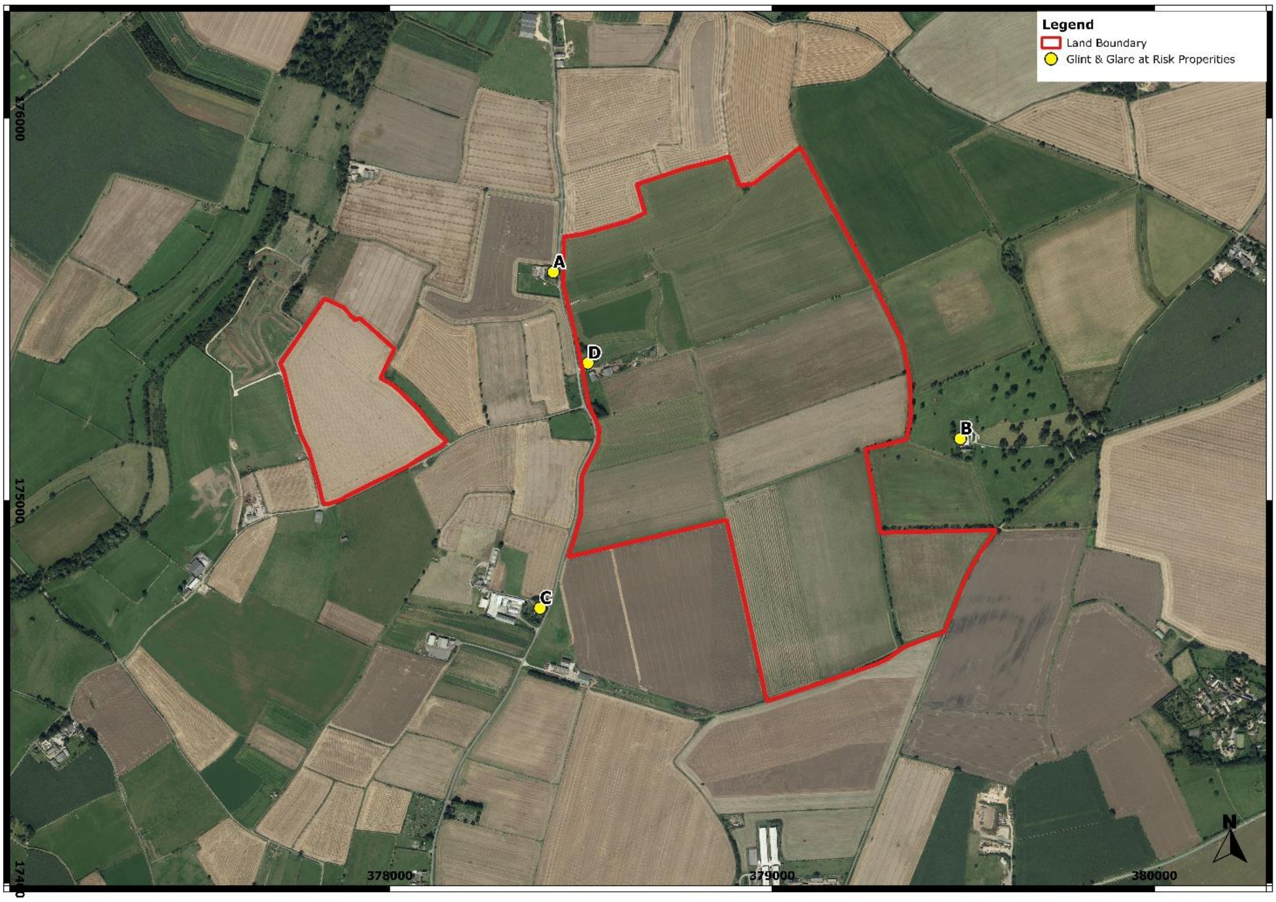

Figure 7: Residential Properties at Risk from Glint and Glare

Transit

There are no motorways passing through or within 1km of both sites. The A420 is located 680m south of the sites however, is relatively well screened by residential dwellings and/or forestry. There is therefore not anticipated to be any glint nor glare impacts on transit.

Aviation

The impact of glint and glare from solar must be considered in cases where the development is within the airport safeguarding consultation zone. The Tiley Field site is located just within aerodrome safeguarding zone for Bristol Airport, c. 29.2km south-west and both sites are within the safeguarding zone for Bristol Filton Airport, c. 19.2km west. Given the distance to the airport, it is unlikely the airport will object to development. However, the airport safeguarding authority is required to assess the potential impact of any solar development on operations if within the consultation zone.

Additionally, there are three airfields within 10km of the site: Garston Farm Airstrip (935m south), Colerne Airfield (3.4km south-west) and Badminton Airfield (7.4km north). Formal consultation will be required with these airfields to assess the possible impact of the wind development on operations but informal discussions with Garston farm has not raised any issues.

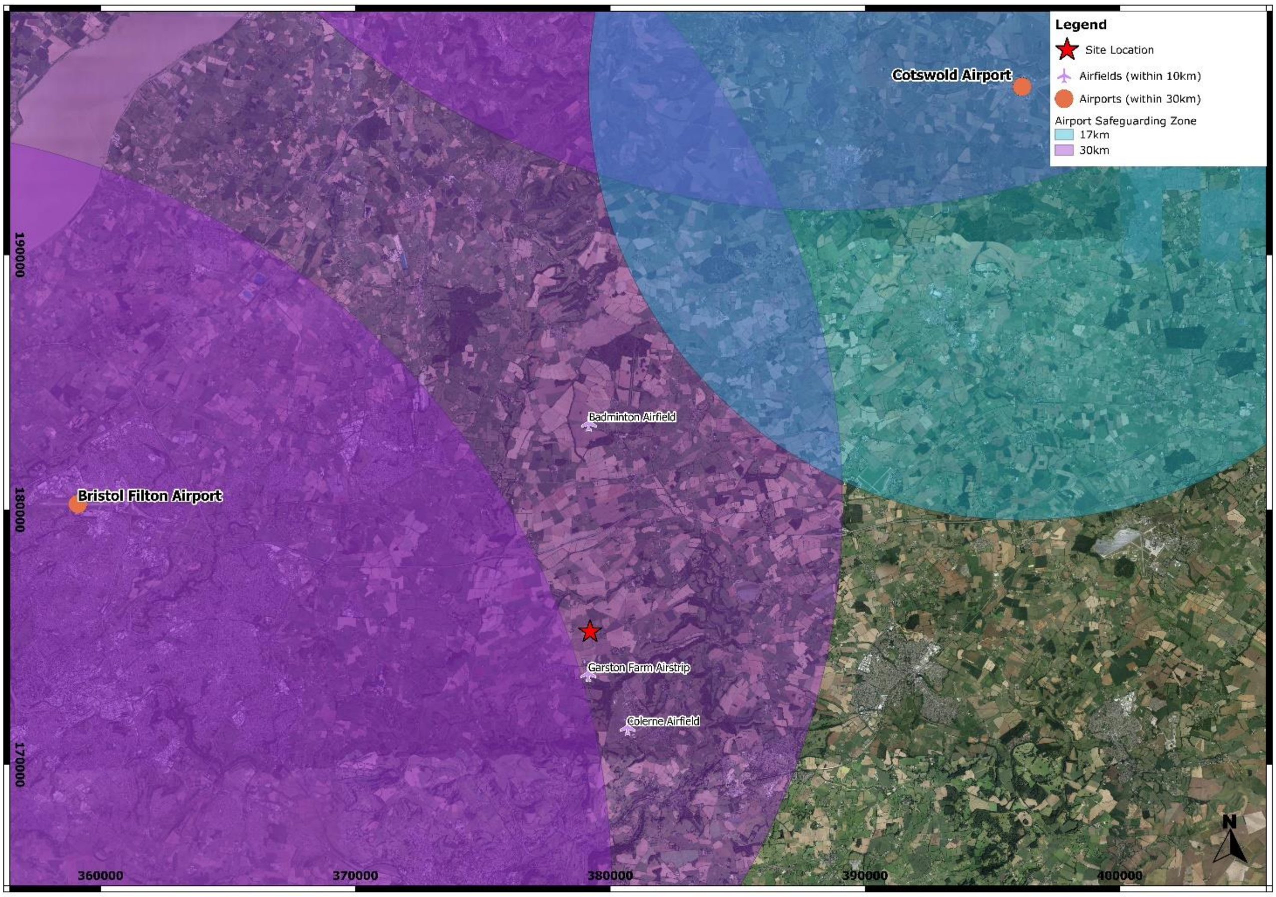

Figure 8: Aerodrome Safeguarding Zones

2.1.9. Noise

Whilst solar projects are not generally 'noisy' relative to other energy generating technologies, several councils in recent developments have asked for this to be addressed. Outwith the construction phase, noise from solar farms (where the panels are mounted statically) generally comes from the inverters and transformers within the substation building(s). It is envisaged that through careful design and location of invertors relative to nearest noise sensitive properties that this issue can be successfully addressed through a simple desk based assessment.

2.1.10. Cumulative impact

Whilst the impact of solar developments to their surrounding environment might be small, the combined or cumulative effects of multiple developments may have a greater impact. Solar developments can affect their surrounding environment and hence a number of environmental impacts are required to be assessed during their planning stage.

Within 10km of the development sites, there are 4 operational ground-mounted solar farms and one application, submitted in June 2021. See Table 1 and Figure 9 below for the scale and distance from the development site of these solar farms.

Solar Farm	Status	Scale	Local Authority	Distance from Development Site
Manor Farm (Wiltshire) - resubmission	Operational	6.3MW	Wiltshire	8.7km SE
Castle Combe Circuit	Operational	12MW	Wiltshire	6km NE
Ring O Bells Farm	Operational	5MW	South Gloucestershire	5.3km NW
Battens Farm Solar Park	Operational	13.1MW	Wiltshire	9.3km E
Leigh Delamere – Solar Farm & Battery Storage	Application Submitted	49.9MW	Wiltshire	9.5km NE

Table 1 - Ground-mounted Solar Farms within 10km of the Development Site

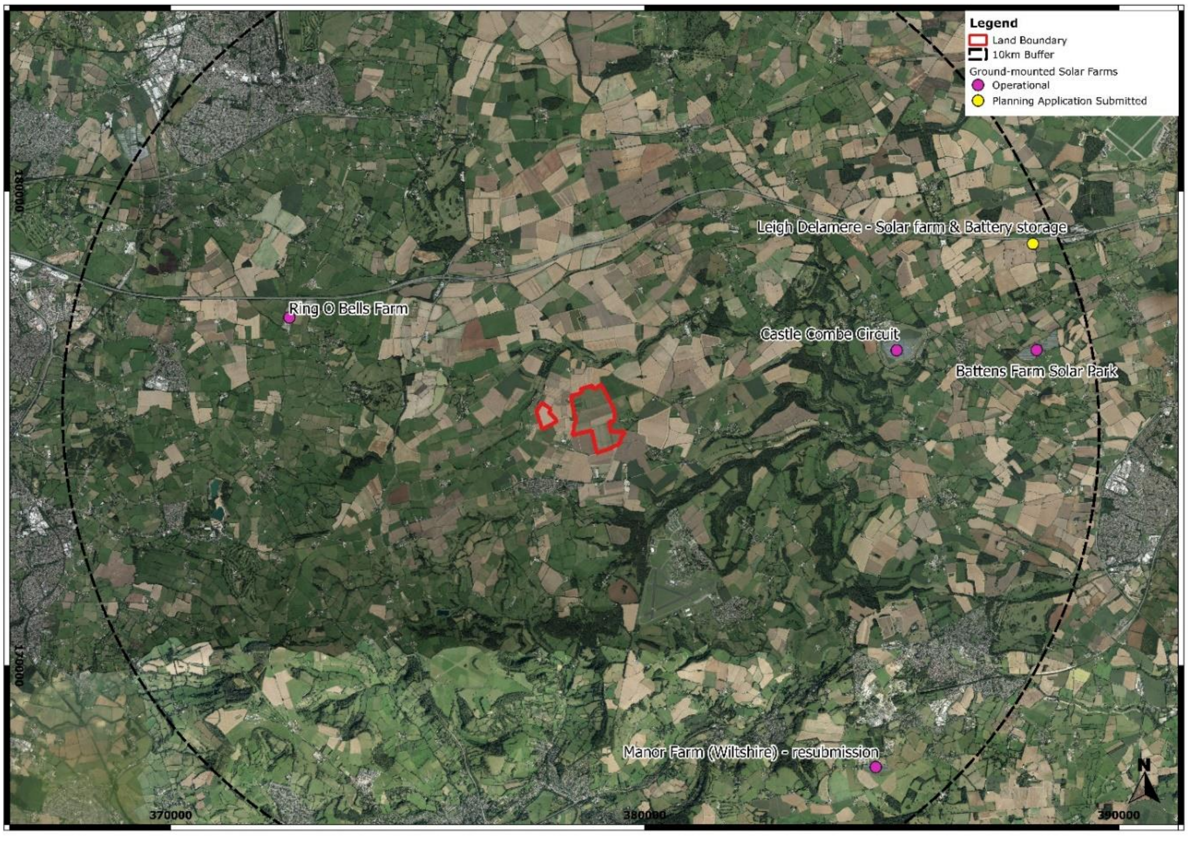

Figure 9: Ground-mounted Solar Farms within 10km of the Development Site

Additionally, with the proposed development being located in the Cotswold AONB, research was carried out to identify operational solar farms located within the designation. There are 4 currently operational solar farms located within the Cotswolds AONB (Figure 10):

- Castle Combe Circuit; 12MW; Wiltshire Local Authority; 6km NE
- Springhill Solar Park (Northwick); 5MW; Cotswold Local Authority; 69km NE
- Northwick Estate (Extension); 2.2MW; Cotswold Local Authority; 69km NE
- Southill Solar (resubmission); 4.5MW; West Oxfordshire Local Authority; 71km NE

Overall, the potential for cumulative effects alongside the proposed solar development is limited due to the limited number of operational solar developments within 10km of the site, with the closest being 5.3km north-west of the proposed site. In addition, with only 4 operational solar farms in the Cotswolds AONB, which are all located out with South Gloucestershire local authority, and the support for community projects in the AONB stated in the Local Development Plan, cumulative issues shouldn't be a challenge.

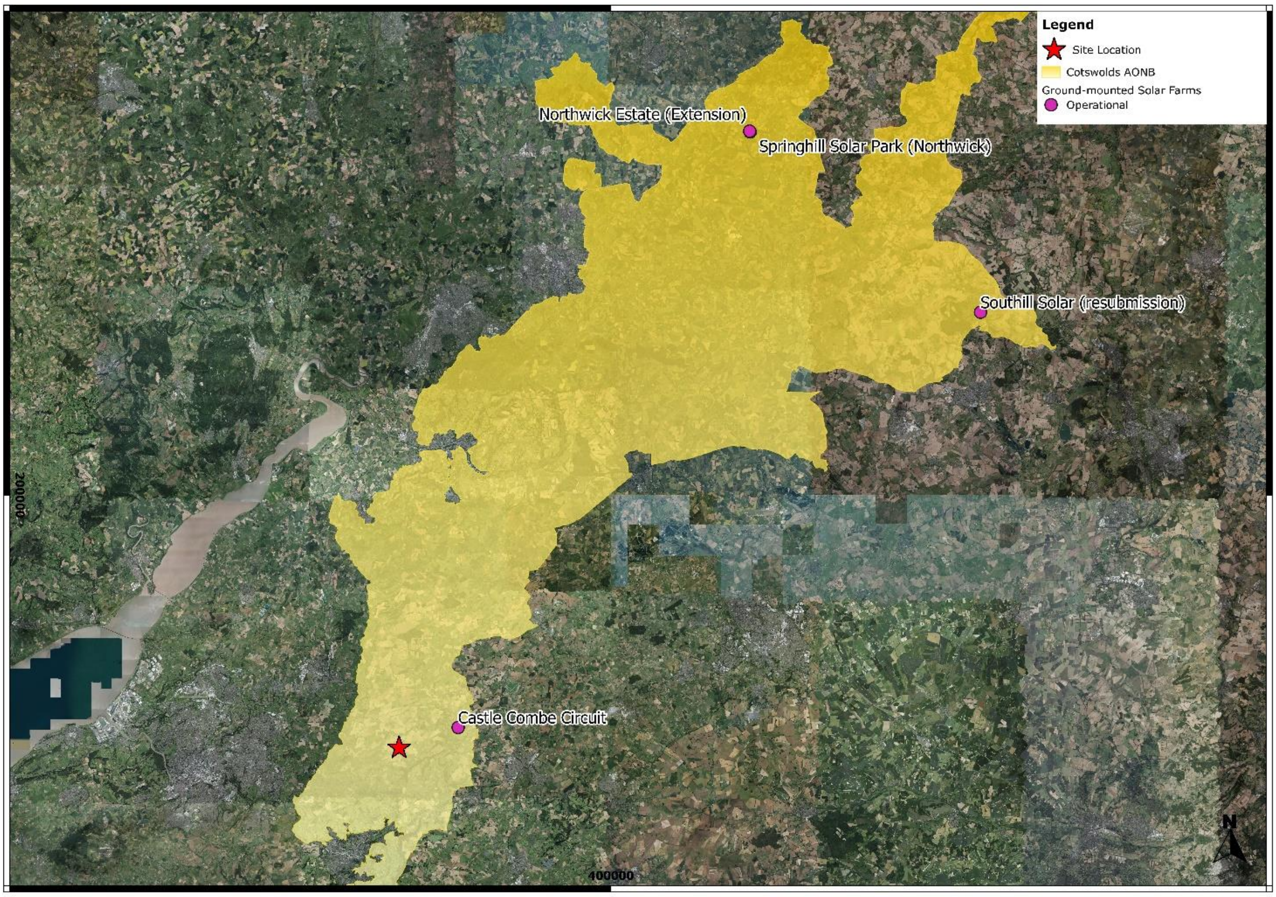

Figure 10: Operational Solar Farms within the Cotswolds AONB

2.1.11. Enhancement opportunities

As a community project, the MCLT solar development already is benefitting the local community moreso than a private development would. Therefore, there is an innate enhancement in the financial benefit to the community, which could in turn fund further community projects and local improvements. Furthermore, this could be an exemplar project in demonstrating how communities can take action and significantly contribute to climate change targets, even in rural, challenging areas.

In addition to this, there are many enhancement measures that could be considered at this site beyond the community benefit, such as the following:

- Often the space between panel rows is neglected, and panels are tightly packed to increase capacity and yield (despite increased losses). By having wide spacing between the panel rows (this outline design suggests 6.4m), there is an option to utilise the land between rows for grazing sheep, and/or as wildlife corridors. This maximises the use of space and could potentially create new habitats, and there is very little benefit in having the panels closer together given the key constraint being the required scale (5MW).
- To improve screening from residential properties or public areas, solar developers regularly look to thicken, widen or plant new hedgerows. While this site is already well screened, thickening hedgerows would benefit the associated habitats. Furthermore, the outline design has allowed for a significant setback from hedgerows to minimise shading. This space could be used to plant species rich, grass mix meadows and wildflowers, creating new habitats and improving wildlife corridors around the site.
- By utilising the existing access and tracks, there is minimal impact on the land. However, the access to other field is improved significantly. If the land was to continue to be used for agriculture, this could largely benefit the farmer. However it is also worth noting the PROWs at Tomarton Road and to the south of the site. Extending the track south and allowing public access could link these PROWs, making the area more accessible.
- There is a nearby footpath to the south of the site. One additional enhancement measure could be to create a view portal (through the woodland) with an information board for users of the footpath. This will educate passers by, raising awareness of climate change and the urgency to take action, as well as enhancing the positive image of the local community.
- The site is well located near to the town of Marshfield and several nearby roads. Its location may be well suited to installation of charging infrastructure for electric vehicles or electric bikes, which otherwise may find obtaining a grid supply challenging. The charging infrastructure could be located on-site, or could be served by a private wire and located nearer to Marshfield or the M4.

This list is not exhaustive, and there have been many other innovative enhancement measures such as art installations; mountain bike trails and pump tracks; footpath lighting, and creation of new specific habitats such as man-made ponds and wetlands. Discussions with stakeholders and survey work would better inform the best enhancement measures for the specific site, based on local needs and demand.

2.1.12. Planning risk summary & mitigation

Table 2 below summarises the aforementioned planning risks and sets out the studies/mitigation required where appropriate, as well as qualitatively categorising the risks from low-high.

Area	Consideration	Studies required/Mitigation (if required)	Rushmead Farm	Tiley Field
Land	ALC	Both sites in ALC3. Detailed study required to determine if ALC 3a or 3b. If ALC3a, could be challenge in planning.	Medium	Medium
Natural heritage	Designated sites	Site is not within IRZ for any environmental designations.	Low	Low
	Habitats	There should be no requirement to remove hedgerows nor woodland and suitable setbacks can be applied to field edges to minimise potential for issues. A Phase 1 ecological survey should be undertaken, though there are not anticipated to be any	Low	Low

		significant habitats due to the agricultural nature of the site.		
	Protected species	Phase 1 ecological survey will identify any protected species present on site.	Low	Low
Cultural heritage	Conservation Areas	Marshfield conservation area is well screened from both sites. Impact on setting should be assessed, and if any visibility is anticipated (following site visit), this should be considered in more detail.	Low	Low
	Scheduled monuments	Several scheduled ancient monuments within 3km of site. The impact on the setting of each should be assessed, and early consultation with Historic England is advisable.	Low	Low
	Listed buildings	Number of grade II listed buildings within 1km.	Low	Low
Amenity and landscape areas	AONB	Site is within Cotswolds AONB. Detailed LVIA will be required to assess extent of impact on landscape character.	High	High
	PROWs	There are no Public Rights of Way that pass through the sites. However, there may be visual impacts on nearby PROWs, especially those to the immediate south of both sites.	Medium	Medium
	Additional	Extent of impacts to be discussed with LPA but initial assessment has not identified any additional nearby amenity areas of high sensitivity.	Low	Low
Glint & Glare (G&G)	Aviation	Both sites are near to multiple operating airfields and within the consultation zone for Bristol Filton airport. Consultation is necessary and a formal Glint & glare assessment will likely be required to ensure no impact on aerodrome operations.	Low	Low
	Transit	For both sites, impact on roads is likely to be negligible. There may be an impact on smaller roads approaching the sites from the east and the west. An assessment of the glint & glare impact may be required.	Low	Low
	Residential	All nearby residential properties look to be well screened from potential development areas within Rushmead Farm site, though the property within the site may benefit from a G&G	Low	Medium

		assessment if visibility is apparent following LVIA. Tiley field looks to be visible from building 400m to east and may be subject to glare impacts.		
Noise	Residential	Distance to local sensitive receptors looks sufficient such that noise is not a concern. This can be confirmed by simple noise modelling if necessary.	Low	Low

Table 2: Summary of planning risks and required investigations/mitigation

The most significant planning risk is currently considered to be the potential impact on the AONB and the local landscape. Early consultation should be undertaken with the LPA and the Cotswolds Conservation Board to quantify the extent of likely issues, however a detailed LVIA will be required to demonstrate whether the potential impacts are acceptable.

2.2. Technical constraints

2.2.1. Site access

There is an existing, wide junction which can be used to access Rushmead Farm from Tomarton road next to the farm buildings at the west of the site. This looks to be accessible from the M4 via the A46 & Cotswold Way, with no steep gradients and no requirement to pass through villages or towns. The existing farm tracks within the site would be upgraded, with some requirement for new tracks within the solar development area.

The Tiley field would be accessed from Rushmead Lane (off Tomarton Road) via an existing farm access in the south east of the field. Again, new tracks would be required within the site boundary.

2.2.2. Utilities

There is a National Grid gas pipeline located c. 1.5km north of the sites. While this pipeline will not be impacted by solar development, a utilities check would be worthwhile to ensure there are no local gas networks passing under either of the sites.

Additionally, there are several overhead lines that pass through the Rushmead Farm site. These all appear to be wooden pole mounted, 11kV lines. Therefore, any solar layout should leave an appropriate distance away from any OHL.

Figure 11 below highlights nearby utilities.

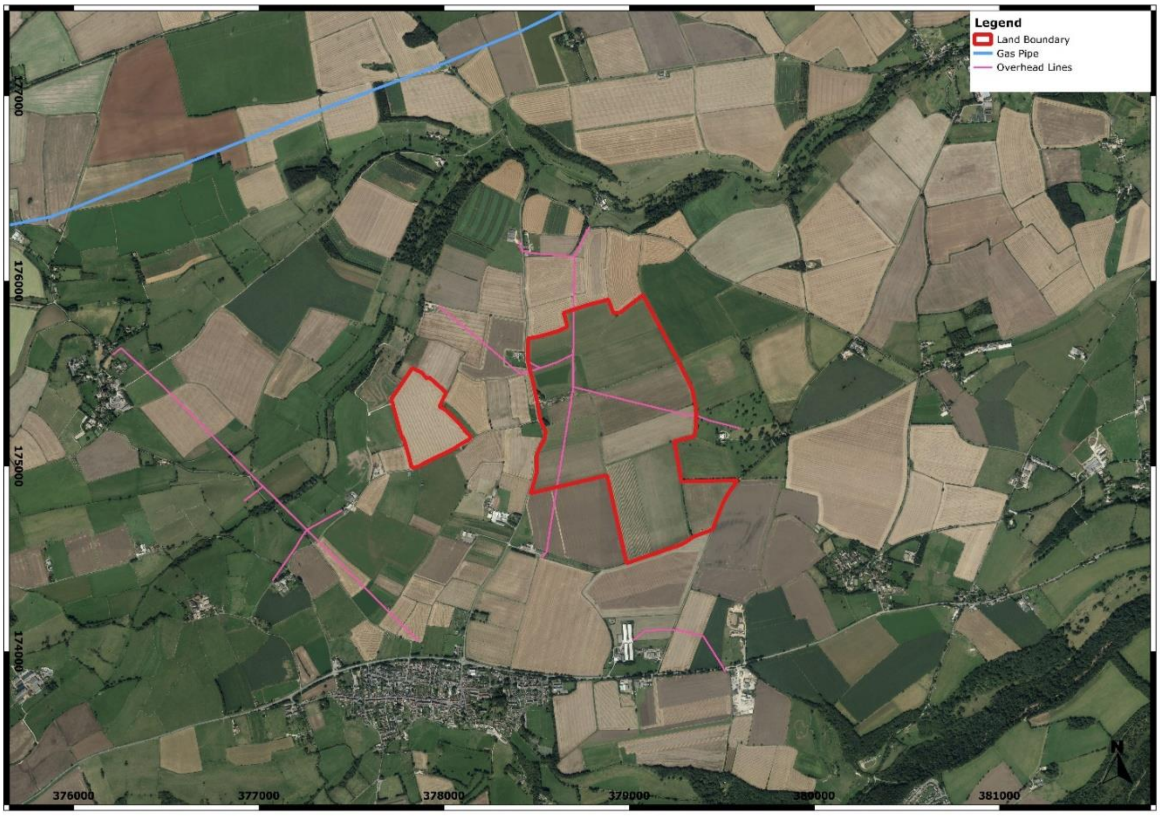

Figure 11: Local infrastructure

2.2.3. Slope/terrain

Rushmead farm is situated on generally flat, rolling farmland with bordering woodland. The site itself slopes gently down to the northwest, but this is not deemed significant regarding loss of yield.

The Tiley Field site is reasonably flat, rolling farmland which very slightly slops to the east at the southeast corner of the site.

Based on OS maps, neither of the site's terrain would be cause for concern in construction.

2.2.4. Grid

Grid connection options are discussed in detail in Section 3, however grid is a key challenge in this project and obtaining a good grid cost is crucial to project viability. There is sufficient space on site for on-site substations and ancillary structures as required.

2.3. Maximum development area

Locogen have accounted for identified development constraints and the areas considered to be available, and suitable, for solar development are illustrated below for each site. In addition to the aforementioned constraints, Locogen have allowed for the following when estimating installable capacity:

- All proposed development areas are to be screened by woodland/hedgerows from residential. Where this is not possible, larger setbacks have been applied;
- Hedgerows/woodland are not to be removed. 10-20m setback has been allowed (dependent on assumed height and relative location) to minimise shading impacts;
- All wooden pole mounted OHLs have been given a safety margin of 6m;
- All steel lattice supported OHLs have been given a safety margin of 16m; and

- All waterways and PROWs have been given a setback of c. 10m.

The developable area of the site is estimated to be in excess of what is available on the electricity grid (discussed subsequently), but ultimately means that whatever scale of solar is installed, there will not need to be a trade-off between installed capacity and shading losses between panel rows. The areas are illustrated in Figure 12 below, with each section's footprint (Ha) indicated.

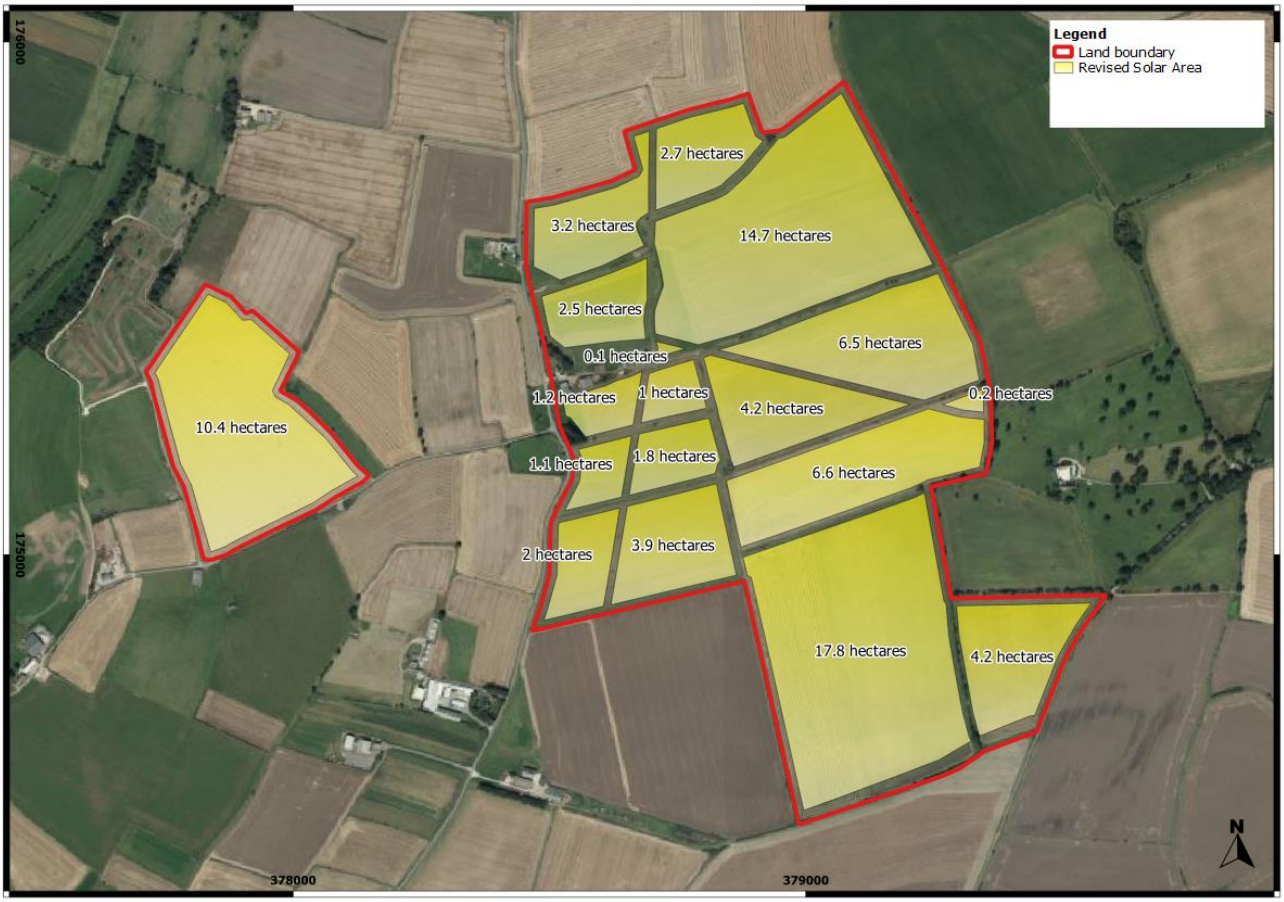

Figure 12: Rushmead Farm and Tiley Field developable area for solar

3. Grid connection

One of the greatest challenges at this location is the prospects for securing a cost-effective export grid connection. The Marshfield site is located in a relatively rural area with the local network only providing local demand.

Locogen investigated several options for connecting to the grid. While the sites are within the Western Power Distribution (WPD) Midlands region, a desktop review of the current grid situation suggested that WPD Midlands was potentially the least suitable of three connection options, with alternative connection routes to Scottish and Southern Energy Network (SSE) region to the east and WPD Southwest (WPD SW) region to the south.

In order to fully assess the best-cost options, Locogen initiated discussions with the neighbouring DNOs as well as following up with WPD Midlands.

The DNO boundaries are illustrated in Figure 13 below with the Rushmead Farm site indicated by the purple circle.

Figure 13: Map showing location of site relative to DNO areas and sub-regions

The variety of connection options are discussed further in the subsequent sections.

3.1. WPD Midlands

Marshfield sits within the Midlands region of Western Power Distribution's network area. Locogen made an initial request to WPD for c. 12MW of generation capacity (estimated maximum available) in order to initiate discussions. Two larger capacity solutions have been provided by WPD Midlands, outlined subsequently, and are illustrated in Figure 14.

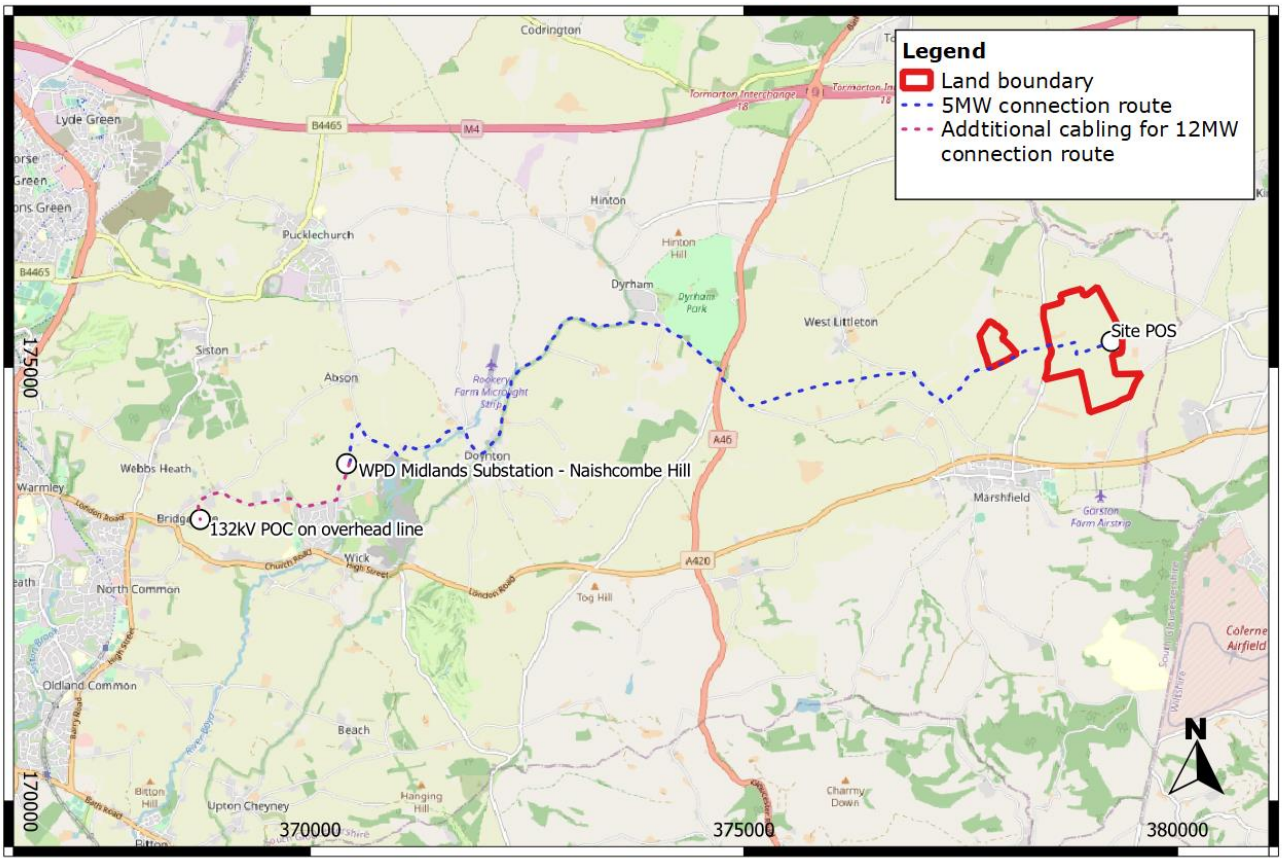

Figure 14: WPD Midlands connection options

Note that network studies are not carried out by the DNO when producing budget estimates. Therefore, network reinforcement at the distribution and transmission levels may also be required for any of the presented options, which might have an additional cost to the provided estimates.

3.1.1. 12MW option

It is known that SGC are investigating alternative renewable energy projects in the local area. Therefore, Locogen investigated the potential for a larger project at the site. The capacity data suggested that the largest possible connection locally would be in the region of 12MW, and therefore Locogen submitted a request for an estimate for a 12MW scheme hoping for an option by which the connection (and associated costs) were shared between the projects.

Unfortunately, WPD Midlands solution for any 5MW+ scheme requires a connection at 132kV and was estimated at £21.6M for the 12MW example. This included:

- Laying of 12km of 132kV cable from the Point of Supply (POS) site substation to the Point of Connection (POC) on the DNO's 132kV network;
- Construction of new 132kV substation at the site; and
- Project progression to National Grid (given 132kV transmission connection).

Furthermore, this excludes:

- Additional cost of traversing obstacles in the installation of cable (such as rivers, major roads or railways); and/or
- Any cost contribution for reinforcement of the existing network upstream (as no network studies are carried out at budget stage).

Locogen attended a surgery call with WPD Midlands in order to better understand the constraints to development and thresholds for cost step-up. Initially, there had been hope for a connection to the 33kV circuits at Naishcombe Hill, c. 8km west of the site. The advice given by WPD Midlands was that every circuit fed by the Iron Acton Grid Supply Point is constrained, with future connections looking at an Active Network Management (ANM) Scheme. ANM is where additional communication and control equipment is installed that allows the DNO to curtail the generator to avoid network issues. This avoids the requirement for major upgrades to the network, and allows for the best use of existing grid infrastructure, but also reduces the achievable energy yield of the project. Due to the number of already existing developments in the WPD Midlands region, this could mean curtailment c. 20% of the time at a loss to the generator. As the majority of projects in the area are solar it may be that additional wind generation would have relatively limited curtailment (given the differing seasonal generation profile) however this would only be confirmed through a more detailed assessment.

The Iron Acton ANM scheme is currently being designed, and WPD have stated that there will be no offered ANM connections until there is better visibility of how the network will look (1-2 years until design is anticipated to be complete). Design and implementation of any new connection would be following this.

Ultimately, this cost, at c. £1.9M per MW installed, renders the 12MW project unviable. The cost for a higher capacity would be similar, therefore the potential does sit for a significantly larger development reducing the £/MW connection cost. However, given the available space for development and existing planning constraints (discussed in Section 2.1) this is not considered to be a viable option.

3.1.2. 5MW option

MCLT shared a budget estimate acquired from WPD Midlands for a 5MW Scheme which was provided in early 2021. This estimated that 5MW could be connected to the 33kV circuit at Naishcombe Hill for c. £2.4M (£480k/MW). The estimate provided limited detail but entailed the installation of 7km of OHL circuit to a new 33kV metered connection. Following up with the engineer, it was estimated that the non-contestable element of the work would be in the region of £400k, such that the OHL circuit and other contestable elements would cost in the region of £2M.

Locogen reviewed this contestable element of a connection from Rushmead farm to Naishcombe Hill substation assuming an underground cable option (for planning purposes), basing costs on experience with recent projects and project-specific discussions with Independent Connection Providers (ICPs). This assessment suggested that a more realistic estimate for the contestable elements would be in the region of £2.25m (totalling 12km), making the total cost of the grid connection approx. £2.5m. However, the more recent feedback on the requirement for ANM means that the overall additional cost for ANM equipment, comms cables and design works could increase this cost to c. £3m, or £600k/MW. There would also likely need to be consideration of potential curtailment.

3.1.3. <5MW options

The local overhead lines (OHLs) and cables are all 11kV circuits and, due to the significant distance back to the substation, the potential connection capacity on these local lines was limited to 1MW. Any larger capacity projects would require a 33kV or 132kV connection. The WPD 11kV planner provided estimates for 1MW and 500kW connections to the existing local 11kV circuits, estimated to cost c. £1,000,000 and £80,000 respectively.

3.2. WPD Southwest

The DNO (WPD) are obliged to give the lowest-cost estimate for the desired capacity in the region but are not obliged to seek alternative connection options outwith their region. Following the surgery call with WPD Midlands, it was agreed that an 'Enhanced Scheme' could be investigated with WPD SW. Locogen had identified Batheaston Substation as a potential connection location, with the connection route likely to be similar to that set out in Figure 15 below.

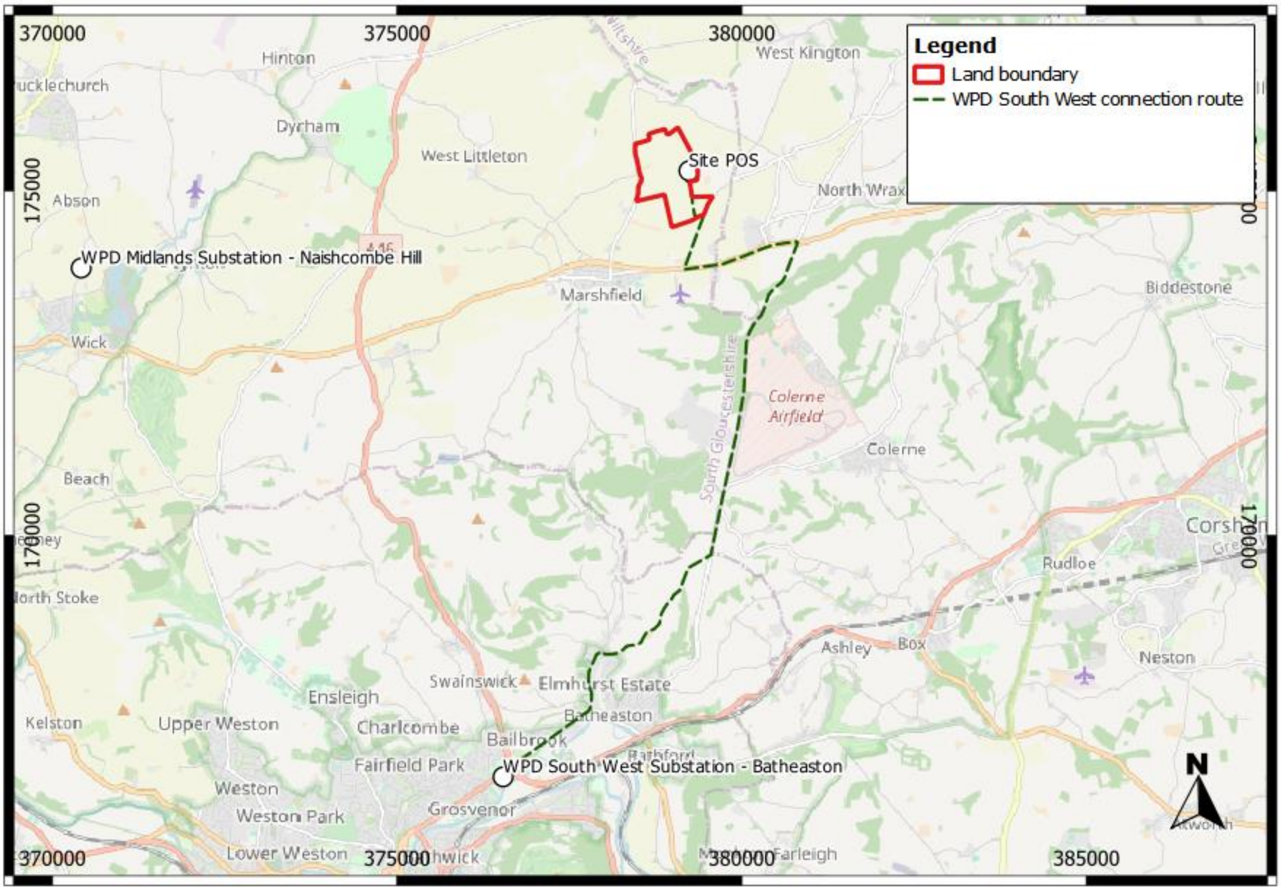

Figure 15: WPD South West connection option

In discussions with WPD SW, it was confirmed that there is unconstrained export capacity available at Batheaston substation, which is part of the unconstrained Dolomeads GSP circuit (i.e. there are no export constraints at this stage). This position is ultimately due to the lack of suitable land for embedded renewables locally around the Bath area, due to planning constraints and high landscape value. For the same reasons, it is proposed that cabling should be laid underground to protect the local landscape and cultural heritage assets.

Ideally, the 33kV board at the Batheaston substation would be extended to accommodate the new connection. If a new board needs to be established, the DNO or Client would need to source land near the substation to accommodate this. Another challenge, due to the distance from the connection point to the site, may be voltage step-change issues. This means that heavier cabling may be required to ensure minimal voltage drop along the route. These costs, if applicable, can only be estimated via a detailed grid study, triggered by formal application.

The WPD SW engineer confirmed that there is theoretically sufficient capacity for up to 24MW of generation on the 33kV circuit feeding Batheason from Dolomeads, although at this point Locogen has assumed a maximum of 20MW being available. This provides an opportunity, in that the grid capacity can be shared, taking advantage of economies of scale, and reducing the community group spend. Therefore, two options have been investigated at this site, 20MW and 5MW, discussed subsequently.

Locogen also addressed the potential for battery storage with the DNO engineer but were advised that the battery import requirements may be problematic in relation to peak import demand. As no curtailment was expected this option was not discussed further.

3.2.1. 20MW option

The high available capacity presents an opportunity for a shared grid connection at the site.

The non-contestable cost of a 20MW connection would be in the region of £400k. Locogen have estimated the cost of the contestable works to be c. £3.2m, which includes for 12.5km of underground cabling following public roads (approximately 40% of which was to be installed under the road, with the remainder assumed to be able to be installed in the verge). With an overall cost of £3.6m, or £180k/MW.

For information the typical cost difference for trenching works (excl. supply and installed of ducted 3-core cables at an estimated cost of £55/m) across different surface types are as follows:

- Trenching in field = £35/m;
- Trenching in grass verge = £60/m; and
- Trenching under the road = £200-240/m (depending on whether partial or fully under).

Discussions with SGC suggested that a realistic apportionment for the community group would be a CAPEX contribution of £500k (or £100k/MW). While this is higher than would usually be considered commercially viable, it is anticipated to be offset by a low rent, and could be partially or wholly funded by community project grant funding.

3.2.2. 5MW option

If the SGC project were not to go ahead, the community would need to wholly pay for the connection to Batheaston. Given that the high-cost elements of the 20MW option (cable route, switchboard extension, etc.) are also applicable to the 5MW option, the costs are not anticipated to differ significantly from the 20MW option. The only significant decrease in cost is anticipated to be due to lighter-weight cabling, and therefore a reduced material cost. Furthermore, given the high available capacity, it is considered unlikely that there will be and significant reinforcement works required if connecting 5MW at Batheaston.

3.3. SSE

Locogen requested a budget estimate from SSE, as their 33kV network is also c. 10km from the site. Their solution looks to establish a new 33kV connection at Yatton Keynell primary substation, with a cable route of c. 10.8km, illustrated in Figure 16 below.

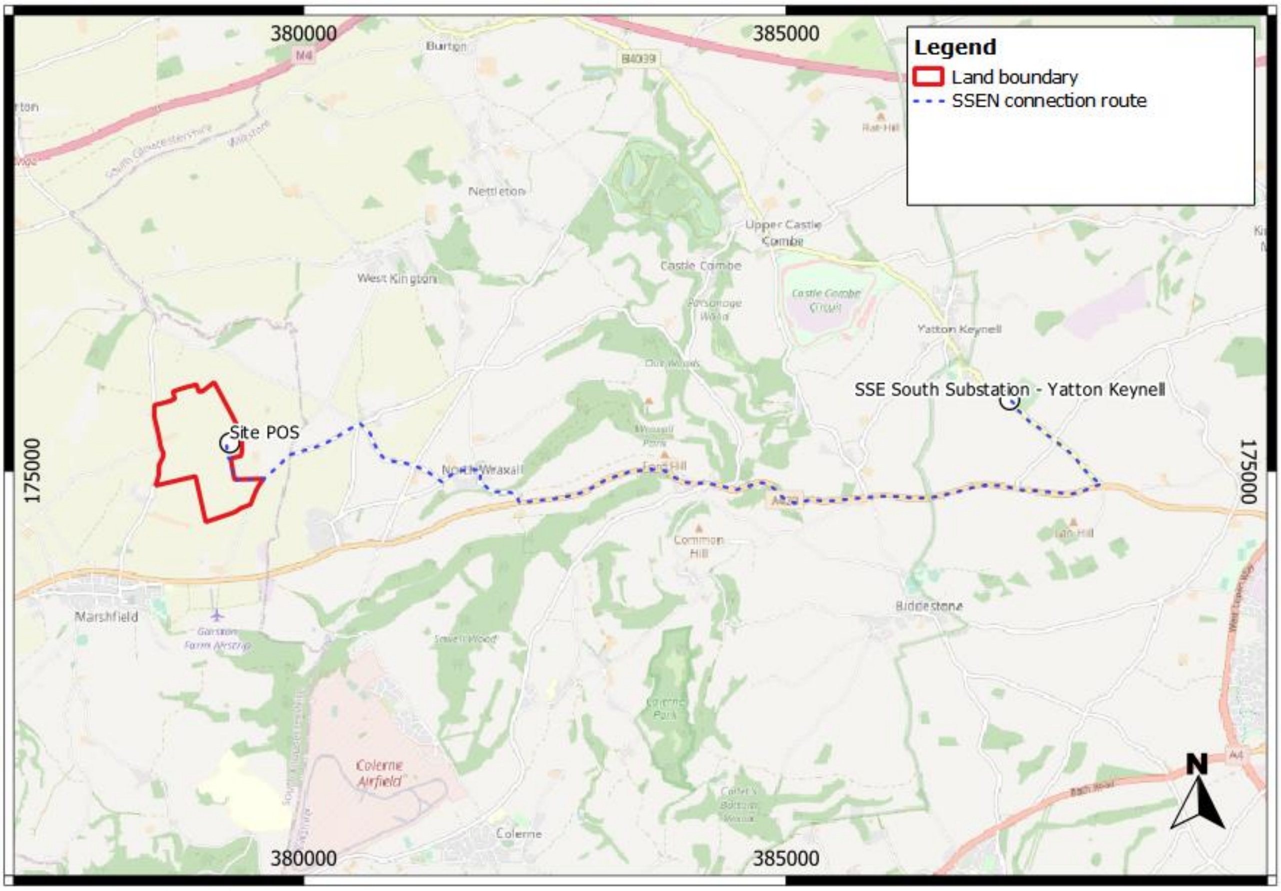

Figure 16: SSEN connection option

The SSE Engineer confirmed that there is sufficient capacity for up to 12MW at Yatton Keynell, and the costs for such a connection would be comparable to the costs of a 5MW project connection, as the same cable route would be required, and any MW scale would be connected onto the 33kV side of the substation. The non-contestable cost of such an installation would be in the region of £450k. Locogen have estimated the cost of the contestable works to be c. £2.8m for a 5MW project, which includes for 10.8km of underground cabling following public roads (approximately 45% assumed to be installed under the road, with the remainder installed in the grass verge). The cost differential for tehnching works will be similar to that set out in Section 3.2.1 although it is likely that a slightly smaller diameter of cable would be utilised given the reduced capacity. This however would likely only reduce the ducted cable cost from £55/m to £52/m.

The costs provided by SSE do not include for upstream reinforcement works. A review of the online substation data suggests there may be thermal limitations upstream of the substation with the Chippenham Bulk Supply Point likely requiring ANM or similar on the basis that the connected and contracted capacity exceeds the firm rating of the substation. Including for ANM means that the overall additional cost for ANM equipment, comms cables and design works could increase the overall cost to c. £3.8m, or £320k/MW. In addition, there would need to be consideration of potential curtailment, given the prevalence of solar in the area.

Similarly to the WPD SW options, three costs have been estimated for the SSEN connections, including an apportioned cost to be shared with the SGC project. However, all of these project would require ANM and therefore a loss of revenue.

3.4. Summary

The above options are summarised in Table 3 below, with the preferred options in bold.

Grid option	DNO	Export Capacity (MW)	Connection voltage	Total cost	Cost per MW	Operational curtailment expected
A	**WPD MID**	**0.5MW**	**11kV**	**£80,000**	**£160,000**	**No**
B	**WPD MID**	**1MW**	**11kV**	**£1,000,000**	**£1,000,000**	**No**
C	WPD MID	5MW	33kV	£3,000,000	£600,000	Yes
D	WPD MID	>5MW[1]	132kV	£21,600,000	£1,900,000	No
E	WPD SW	20MW	33kV	£3,600,000	£180,000	No
F	**WPD SW**	**5MW**	**33kV**	**£3,000,000**	**£600,000**	**No**
G	**WPD SW**	**5MW (apportioned)**	**33kV**	**£500,000**	**£100,000**	**No**
H	SSEN	12MW	33kV	£3,800,000	£320,000	Yes
I	SSEN	5MW	33kV	£3,200,000	£640,000	Yes
J	SSEN	5MW (apportioned)	33kV	£800,000	£160,000	Yes

Table 3 - Breakdown of potential grid connection options

Both of the larger capacity WPD Midlands solutions are extremely expensive and are unlikely to enable a viable project return, while the smaller solutions are outside the scope of the project (although Option B may be a suitable back-up, should planning not favour the 5MW project). The WPD SW solution currently appears to be the best option for the project. This solution has the greatest capacity available; has no known upstream constraints; is anticipated to have no operational curtailment (based on current contracted capacity), and ultimately has the lowest estimated connection cost per MW. Options H&I (SSE) also present a potentially viable solution, and benefits from a comparatively straight-forward connection route (without having to pass through urban areas unlike Options C-E). However, the risk of complications upstream (thermal constraints; transformer rating, etc.) is significantly higher given existing network pressures in the SSE area. Therefore, the financial assessments have utilised the cost option to connect to Batheaston substation.

The following points should be noted:

- The provided cable costs have made baseline assumptions regarding the ability to use identified areas of road verge along the route. Further assessment is required to ensure that existing utilities are not utilising this verge and confirm the proportion of the route that can utilise the verge (30% of the cost of running under the road) as this will have a significant impact on the overall cost.
- All connection cost estimates are based on utilising public roads. Subject to agreement with landowners, there is the potential to utilise third party land to reduce the overall length of cable route (through more direct routes cross country) as well as reducing costs (if can avoid sections of higher cabling cost and agree cost effective easement payments). It is recommended that this be explored in more detail in the next stage of development.
- There is currently a high level of activity on distribution grid networks with developers securing export grid capacity (primarily for solar and storage projects). Therefore, it is recommended that grid applications are submitted early in development to ensure that the necessary capacity can be secured.

[1] Estimate for 12MW, but generally representative of any project 5-12MW. No connection possible >12MW.

4. Outline Specification

4.1. Technology

Below provides an outline of equipment and layouts that the Client may expect to see from their EPC contractor. As the market is always evolving and technology is always improving, it is likely that the solar farm design will adapt accordingly. The below is representative of solar farms developed and installed by Locogen at similar scales.

Panels

The systems suggested for this site consist of high-performing 400W Monocrystalline Silicon solar panels (nominal model: JA Solar). This is a common size in modern ground-mounted systems. Each panel measures c. 2.2m x 1.0m and weighs approximately 24kg.

Mounting

Generally, solar panels are mounted on metal frames with appropriate ground anchoring, which could be screw anchors, piled foundations or ballast systems. Ballast foundations would add ~10% to the total capital cost of a screw anchor option (assuming no other works are required to allow for the screw anchor option). The frames set the panels at an optimal angle to collect the most energy from the sun. They must also be capable of withstanding environmental conditions for the anticipated 20-30 year project lifetime.

For this project, Locogen have utilised panel rows consisting of three panels high arranged in landscape (see Figure 17 below). This is a popular and cost-effective configuration. Furthermore, given the space available to the Marshfield project, the arrays can have wide row spacing, allowing for the panels to be at a lower height (<3m) and higher angle (30^{o}) without significant shading losses.

Figure 17: Solar Panel Rows

Following several yield iterations, Locogen estimates the optimum row spacing to be as follows:

- Slope: 35^{o}
- Orientation: 180^{o} (south)
- Inter-row spacing: 6m

Ancillaries

Other key ancillary equipment for a ground-mounted solar array includes:

- **Inverter kiosk(s)** –The solar panels are connected in strings which are then connected to inverters to convert the electricity to grid quality AC power. These are located at intervals within the solar array, to minimise cabling distances.
- **Electrical substation building** – This infrastructure will be required if the site is a stand-alone project that will export straight back to the grid. Typically, this will be a brick or Glass Reinforced Plastic ('GRP') building that houses the transformer, switchgear and protection equipment for the scheme. This building would also have space for the Distribution Network Operator's ('DNO') electrical equipment.
- **Construction compound** – This is typically required for larger stand-alone projects. An area of hardstanding may be installed for the safe delivery and assembly of the solar array equipment. The size of this area will depend on the scale of scheme installed and, for large schemes (5-10MW), would normally comprise of a compacted area of hardcore measuring c. $500m^2$. During operation, the area would generally be retained and used for any maintenance works that may be required.
- **Fencing** – In order to provide suitable security, a 2.5 metre fence (e.g. weldmesh) would be proposed around the full perimeter of the array.
- **Security** – In addition to the above fence, it is recommended to install an infrared detection system and a remote camera surveillance system. Using infrared technology would avoid the need for security lighting, to avoid impacting the dark skies of the AONB and complaints from local residents.

4.2. Location & scale

4.2.1. 5MW Project

An outline layout and indicative scale for a 5MW project is illustrated in Figure 18 below. Although any of the locations within Rushmead Farm highlighted in Figure 12 would be suitable, this particular location has been prioritised as it appears to be the least visible from nearby properties and public areas (as discussed previously).

Figure 18: Outline layout for 5MW project at Rushmead Farm

4.2.2. 1MW Project

An outline layout and indicative scale for a 1MW project is illustrated in Figure 19 below. This project scale has been proposed as an example in the Tiley field, although at this scale there is also more scope to accommodate the development and overcome constraints within the larger site.Figure 12

Figure 19: Outline layout for 1MW project at Rushmead Farm

4.3. Energy Yield Assessment

Industry standard software PVSYST was used to optimise the layout and estimate the yield at the site. The nearby trees and hedgerows are included in the model, with a setback of 20m. Terrain data was not available for the site, but as there is more land available and the row spacing has been generous in this model, it is anticipated that a detailed design including terrain would provide similar results.

The outcomes of the yield assessment are outlined in Table 4 below.

Project	**5MW**	**1MW**
No. panels	14,500	3,000
Peak (DC) capacity	5.8 MW	1.2 MW
Inverter (AC) capacity	5 MW	1 MW
Estimated Y1 gross energy yield	7,234 MWh	1,442 MWh
Performance Ratio	88%	88%
Estimated Y1 net energy yield	6,366 MWh	1,273 MWh

Specific yield	1,092 MWh/MWp	1,060 MWh/MWp

Table 4: Yield Assessment Outcomes

Specific yield (MWh/MWp) is a common performance metric for solar farms. It ultimately compares energy delivered (MWh) to total installed DC capacity (MWp). For smaller systems, it may be presented as kWh/kWp with the same meaning. Where there is a lot of space and the site is constrained by grid capacity, a developer would be looking to maximise the specific yield. However, if there is limited space and more grid capacity available, a developer may trade-off performance to increase energy output (MWh) while spending more on the capital costs of additional installed capacity (MWp).

It should be noted that the above figures represent the year 1 expected net energy yield for the array assuming 'typical' solar resource conditions. The financial modelling includes an annual performance degradation for the panels and associated equipment which is the equivalent of a 0.4% reduction in yield for each year of operation. This panel degradation is well understood, and manufacturers will typically warrant similar levels of performance reduction for a c.20 year period as part of their sale.

The above energy yield estimate is utilised in the next section when calculating project revenues and financial returns.

4.3.1. Export limitation option

Locogen modelled, on an hourly basis, the impact of export limitation on the 1MW option. A G100 export limitation scheme could be installed, limiting the export to 500kW and therefore allowing for the lower cost grid connection to be utilised. It was seen that, subsequent to losses within the system and inverters, the total exported energy would be in the region of 1,035MWh. This is a 18.6% decrease in exported energy and the consequent generation-based income.

Locogen utilised the hourly generation data to estimate an appropriate battery size to capture this energy for sale when the PV scheme is not exporting. Table 5 below illustrates the energy that could be recovered (that would otherwise be curtailed) by various battery sizes based on the 500kW export limit. This assumes a ratio of 1MW:2MWh (2-hour discharge period) and a 92% charge/discharge efficiency.

Battery size	0.5MW	1MW	1.5MW	2MW	3MW
Battery capacity	1 MWh	2MWh	3MWh	4MWh	6MWh
Energy exported from battery to grid	128.6 MWh	189.3 MWh	201.2 MWh	201.2 MWh	201.2 MWh

Table 5: Impact of battery on 1MW system, export limited to 500kW

This highlights that there is no requirement for a battery more than 1.5MW/3MWh, where the additional available energy plateaus. Based on this high-level assessment, a 1.5MW/3MWh battery would be the optimum size for this site, provided that the value of the additional available energy (c. 201.2MWh in year 1) would be sufficient to justify the CAPEX and ongoing OPEX of the battery installation and operation.

4.4. Performance relative to nearby operational site

Figure 9 (shown previously in Section 2.1.10) indicates the site location relative to the nearest operational solar farm at Castle Combe Circuit.

The Castle Combe Circuit project is c. 18MWp, located c. 6km northeast of the Marshfield site. The project was commissioned in 2015 and the ROC data (including MWh generated) is available for analysis.

Based on 4 full years of ROC data, it appears that the Castle Combe project produces on average 928.5 MWh/MWp installed. This is slightly lower than the estimations for the Marshfield site, however, there are several reasons that this may be the case:

- We have public information on the MWh exported to the grid for the site, however, there is limited information available regarding the specific AC or DC capacity, and thus the potential performance of the site relative to the locational data.
- The provided yield figures for these proposed solar arrays are year 1 figures and, for the operational sites, there will be some gradual reduction in performance over the initial period of operation due to panel degradation to account for.
- This particular development would have been under significant time pressure to be installed prior to reductions or the end of generation-based incentives (as they are RO or FiT projects). This may have led to design decisions or technologies being utilised to ensure commissioning dates were met instead of aiming to improve long term performance.
- The improvements in technology in the interim will lead to some partial improvement in the overall system performance. It is expected that the performance of a new, larger capacity system should benefit from improved performance when compared to existing operational sites.

Overall it is considered that the energy yield figures provided in Section 4.3 are reasonable and achievable. The projected yield figures have been utilised in the next section when setting out the financial returns that are expected for the site.

5. Financial and Carbon modelling

Four options were taken forward:

- Option 1: 5MW project onto WPD Midlands 33kV network;
- Option 2: 5MW project, onto WPD Southwest 33kV network, cost apportionment with SGC;
- Option 3: 1MW project onto WPD Midlands 11kV network;
- Option 4: 1MW project onto WPD Midlands 11kV network, export limited to 500kW.

5.1. Project costs

5.1.1. Development costs

Locogen have provided a breakdown of the expected grid, planning, technical and PM works in Table 6 below for the proposed solar development options. Note that costs are consistent between options 1 & 2 (as they are both 5MW capacity) with the exception of costs associated with the grid. It is assumed that the development-stage grid costs would be paid in full by partnered project, with a single CAPEX to the community group, included in the proceeding section.

Area	Subtask	Option 1	Option 2	Options 3 & 4
General	Project Management and Liaison throughout development	£6,000	£6,000	£4,000
Planning	Screening and stakeholder engagement	£1,500	£1,500	£900
	Planning Co-ordination - up to planning decision	£5,000	£5,000	£1,200
	Planning Design and Access Statement (includes sequential assessment on site selection)	£2,500	£2,500	£1,400
	Application plans and drawings	£1,500	£1,500	£1,500
	LVIA (including mitigation and management plan)	£5,000	£5,000	£2,000
	Ecology (including environmental mitigation and management plan)	£4,000	£4,000	£2,000
	Glint and Glare (including aerodrome assessment)	£1,500	£1,500	£1,500
	Agricultural land classification survey	£2,000	£2,000	£1,500
	Supporting environmental document (incl. secondary chapters)	£5,000	£5,000	£3,000
	Planning application forms and submission	£900	£900	£900
	Application Fee (based on Ha of development)	£38,039	£38,039	£13,860
Grid	Grid application works	£1,200	£0	£900
	WPD grid application fees	£4,895	£0	£0
	Grid Payment on acceptance of offer	£15,000	£0	£18,000
	Transmission impact application to NGESO	£5,000	£0	£1,000
Total (excl. contingency)		**£99,034**	**£72,939**	**£53,660**
Contingency @5%		£4,952	£3,647	£2,683
Total cost (incl. contingency)		**£103,986**	**£76,586**	**£56,343**

Table 6: Estimated development cost for the Marshfield array options

The above costs would be expected to take the project through securing grid capacity and a planning decision. The scope of the planning works has been estimated at this time based on a typical package of ecological works. The most likely use for the contingency works is in the potential requirement by stakeholders to complete more detailed ecological or ornithological studies if required.

5.1.2. Capital costs

Outline capital expenditure (Capex) items are provided in Table 7 below for the proposed solar development options. These estimated project costs include for the full array and Balance of Plant (BoP) costs. The grid connection costs are based on the findings of the grid assessment in Section 3. Note that costs are consistent between options 1 & 2 as both are 5MW projects) with the exception of the grid cost.

Cost item	Option 1	Option 2	Option 3	Option 4
Planning condition discharge	£10,200	£10,200	£4,000	£4,000
Surveys (topographical, services & ground investigation)	£10,000	£10,000	£5,000	£5,000
Pre-construction PM (incl. procurement)	£25,000	£25,000	£15,000	£15,000
EPC cost for installation	£2,475,000	£2,475,000	£562,500	£562,500
Grid connection	£3,000,000	£500,000	£1,000,000	£80,000
Construction PM (owner's engineer)	£15,000	£15,000	£10,000	£10,000
Construction insurance and additional ad-hoc items	£17,800	£17,800	£4,200	£4,200
Total cost (excl. contingency)	**£5,553,000**	**£3,053,000**	**£1,600,700**	**£680,700**

Table 7 - Capital expenditure for solar array options

For a PV plant, the EPC contract would typically provide a full scope of services covering engineering, procurement and construction costs. This would include major component cost items such as PV modules and, for example, inverters. Nevertheless, these are broken out below because EPC contract price would likely be adjusted if these vary significantly:

- PV modules at c. £150,000 per MWp.
- BoP components at c. £100,000 per MWp (this consists chiefly of inverters, DC subsystems, transformers, switchgear and AC subsystems).
- Mounting structures at c. £60,000 per MW
- Remaining EPC costs of c. £140,000 per MWp.

The expected civil and electrical costs have been estimated based on industry standard costs.

5.1.3. Operational costs

The estimated year one annual operational expenditure (Opex) for the solar array is provided in Table 8 below. This breakdown includes for operation & maintenance, insurance, third party asset management and metering.

Initial consideration of business rates payable has also been included, although there is currently no clear methodology for valuing subsidy free projects and so there is greater risk applied to this cost estimate. Therefore, a sensitivity of the projects to a discount in rates has been investigated subsequently.

In addition to the ongoing operational costs that would likely be incurred, Locogen have also included for an ongoing annual payment towards inverter and panel replacement which is expected to occur once over the assumed 30-year operational life of the project. In this estimate, we have also assumed that 1% of the installed panels will require replacement over the 30-year operational life. For this assessment, we have assumed a 20% reduction in inverter price from today's prices, whilst the panel prices are assumed to drop by 30% over the replacement period.

Cost item	Option 1 & 2	Options 3 & 4
Asset management fee	£5,500	£5,000
Accounting and bookkeeping	£4,000	£3,500
Ongoing compliance works (monitoring and reporting)	£1,500	£0
Metering and site consumption	£3,900	£2,000
Rent[2]	£20,250	£4,350
O&M costs	£22,000	£7,000
Operational insurance	£7,750	£1,550
Business rates	£13,250	£2,650
Inverter & panel replacement fund	£4,600	£1,000
Total cost	**£82,750**	**£27,050**

Table 8: Estimated year 1 Opex for the solar array options

Rent was advised by the Client to be included at a cost of £750 per acre of the estimated leased area (within fence line).

5.2. Project revenue

The export rates used in this base case assessment are based on a predicted long-term electricity value for solar generation connected to the distribution network. This is on the assumption that the project is able to sign up to 1-2 year merchant PPA agreements with suppliers on a rolling basis. A year 1 value of £50/MWh has been utilised and this is inclusive of any Renewable Electricity Guarantee of Origin (REGO) certificate. Future energy prices will be subject to market changes; however, this initial base case financial model assumes that future electricity prices will rise over the duration of the project in line with an assumed energy price inflation.

5.3. Financial analysis

The assumptions used to complete this base-case financial assessment are as follows:

- An annual performance degradation of 0.4% has been applied to the energy yield;
- This is an unlevered financial model (no inclusion for loans or finance);
- Results include the potential requirement to pay corporation tax but do not consider VAT, additional income tax or any return via the capital allowance scheme for new equipment;
- The electricity value is assumed to rise at 2.0%/year over the project life;
- The OPEX are linked to RPI which is assumed to rise at 2.5%/year over the project life;
- A 5% discount rate has been used for calculating the Net Present Value; and

[2] Rental values are based on the layouts provided in section 4.2. However, as noted these are generously spaced given the initial assumption of low rent in previous versions of this report. Indicative areas for solar farms can range from 0.9-2 hectares per MW(dc) installed. A developer may seek to install a dense, less efficient system with a higher CAPEX (due to more panels) and increased shading loss, but genering more energy per m^2. This method can reduce OPEX due to lower rent requirement, but will decrease efficiency and increase CAPEX for the project.

- 'End of life' for a new solar array has been put at 30 years which corresponds with the operational design life of a modern solar development (subject to replacement costs).

Table 9 below demonstrates the expected project returns based on the estimated development, capital costs, operational costs, yield, revenue streams and stated assumptions.

Project	**Option 1**	**Option 2**	**Option 3**	**Option 4**
1st year net annual generation (MWh)	6,366	6,366	1,273	1,035
Total project CAPEX	£5,652,034	£3,125,939	£1,654,360	£734,360
1st year gross revenue	£318,300	£318,300	£63,650	£51,750
1st year annual OPEX	£82,750	£82,750	£27,050	£27,050
1st year net revenue	£235,550	£235,550	£36,600	£24,700
Payback period (years)	21	12	no payback	no payback
20-year Net Present Value	-£2,241,446	-£28,938	-£1,094,081	-£378,547
20-year Internal Rate of Return	-0.38%	4.89%	-5.67%	-2.52%
25-year Net Present Value	-£1,823,304	£378,748	-£1,019,137	-£329,746
25-year Internal Rate of Return	1.39%	6.22%	-2.98%	-0.27%
30-year Net Present Value	-£1,481,006	£720,521	-£956,704	-£295,834
30-year Internal Rate of Return	2.49%	6.98%	-1.30%	0.91%
1st year CO_2 savings (tonnes)[3]	1,528	1,528	306	248

Table 9: Base case financial assessment for the solar development options

The above table demonstrates that Option 2 solar development (sharing the grid cost) offers a relatively attractive financial return for development in this subsidy free setting. Option 1 also pays back within the 30-year operational period, but would be improved by increasing the generation capacity at the site to achieve best value-for-money in the grid connection.

Option 3 (1MW) unfortunately does not provide a commercially attractive financial return. This was anticipated by the Client, however, should there be an offer of capital grant funding for the project, or arrival of a local/sleeved consumer which would pay a higher price for the energy generated, then this scale of development may become a viable opportunity.

Unfortunately, While an improvement on Option 3, Option 4 also does not offer a viable pay back despite the decreased grid cost. This is ultimately due to reduced economies of scale of the 1MW option. There are disproportionately high development costs (c. 7% of total project cost in Option 4; c. 3% of total project cost in Options 1-3). Finally, whilst the grid related costs are lower there is significantly less exported energy from the export curtailment while the overall non-grid capital costs are the same.

[3] Assumes each kWh of electricity offsets 0.24kg of CO_2. Due to the assumed future decarbonisation of the electricity network this figure will reduce in future years.

The key benefits being presented by the 5MW project are as follows:

1. **Longer operational life**: A well-constructed and maintained solar site should have an operational life of c. 30 years. This extends the time period to secure a strong overall return on investment and, as an ongoing replacement fund is included in the OPEX for equipment that will need replacing, is considerable achievable. Some investors are looking at extending the operation of their solar farms out further than the proposed 30 year period but this may require additional consideration of replacement works and there is greater uncertainty on the overall financials.
2. **No inclusion for land rental**: As the Council own the land for development no rental has been included in the base case model. If the Council wished to charge a commercial rental (equivalent to £900/acre) then the annual rental payment would be just over £106,000 in year 1 and lead to 0.8-1.0% reduction in the achieved IRR at the 20, 25 and 30 year periods.
3. **Higher than average AC/DC ratio**: For this project a ratio of 1:1.25 has been utilised to maximise the overall achieved generation for the site. This ratio is higher than would normally be expected with modern developments typically working on ~1:1.18. The additional cost of the modules, frames and cabling for this approach has been included in the financial model and overall it appears to provide a slight uplift in the returns achieved compared to new subsidy free solar farm projects.
4. **Stable energy price**: This base case has assumed that the overall value achieved for generation is the equivalent of £50/MWh in year 1 with future values linked to inflation. Whilst the year 1 price is considered to be relatively low based on current PPA pricing, there is a significant benefit to long term revenue from the price certainty applied to the model. Under merchant conditions the price may vary over the years with general market conditions. In the longer term a considerable increase in solar installed capacity may depreciate summer day prices and lead to lower PPA values being achieved. The sensitivity analysis considers the impact of varying electricity pricing, and this report also considers ways that the Council could "lock in" future rates through sleeved PPAs.

The next section considers an initial sensitivity analysis through amending some of the key variables set out in the base case assessment.

5.3.1. Option 5 (addition)

MCLT have suggested an additional assessment of the potential for a 1MW project, with a grid connection of £80,000 and unconstrainted export.

Project	Option 4	Option 5
1st year net annual generation (MWh)	1,035	1,273
Total project CAPEX	£734,360	£734,360
1st year gross revenue	£51,750	£63,650
1st year annual OPEX	£27,050	£27,050
1st year net revenue	£24,700	£36,600
Payback period (years)	no payback	18
20-year Net Present Value	-£378,547	-£225,161
20-year Internal Rate of Return	-2.52%	0.91%
25-year Net Present Value	-£329,746	-£164,104
25-year Internal Rate of Return	-0.27%	2.54%
30-year Net Present Value	-£295,834	-£113,431
30-year Internal Rate of Return	0.91%	3.55%
1st year CO2 savings (tonnes)1F[1]	248	306

Table 10: Option 4b financial assessment

This represents a scenario where a constraint agreement is in place, but the constraint is rarely applied (negligible). The key change therefore is in the net annual generation, which is equivalent to that of Option 3 (unconstrained 1MW connection). This, as would be expected, improves the financial feasibility of the project substantially.

5.4. Sensitivity analysis (Option 2)

Locogen has undertaken an initial sensitivity analysis to consider the impact on the financial returns from amending key project variables to the base case assessment. This sensitivity analysis has been completed for **Option 2**, as the preferred development option.

The variables investigated at this stage are:

- Contingency in CAPEX & DEVEX costs;
- Impact of DEVEX funding;
- Impact of CAPEX grant funding;
- Impact of securing PPA at varying rates; and
- Discount on business rates for subsidy-free, community project.

5.4.1. Variability in CAPEX/DEVEX

At the Clients request, Locogen have not included for any generalised contingency in the financial models (but rather 'cost tolerances' as set out in Appendix A. This section therefore reviews the impact of variability capital and development costs on the project financials. If the project were to overspend or underspend by 5%, the key financial outputs would be as outlined in below.

Variability in CAPEX+DEVEX	-5% (underspend)	**0%**	+5% (overspend)
Y30 IRR	7.4%	**7.0%**	6.6%
Payback period	12	**12.4**	13

Table 11: Impact on financials of varying applied contingency

As would be expected, the financial returns are improved significantly with this variation in costs.

5.4.2. Development & Capital funding

It is not uncommon for community groups to obtain grant funding for project development costs. The impact of such funding is outlined in the table below.

% development funding	**0%**	50%	100%
Y30 IRR	**7.0%**	7.1%	7.2%
Payback period	**12.4**	12.3	12.2

Table 12: Impact on financials of obtaining development funding

It is seen that development funding has marginal impact on the project returns, it's impact on all projects is compared in Section 5.5. As the grid costs in the development stage are likely to be fully covered by the development partner, the total development cost in Option 2 is low compared to the Capital expenditure. Should the project be successful in obtaining grant funding for all capital costs (including development costs) returns would be further improved, as outlined below.

% capital funding (dev costs 100% funded)	**0%**	**25%**	50%	75%
Y30 IRR	**7.2%**	10.0%	15.1%	29.0%
Payback period	**12.2**	9.4	6.6	3.4

Table 13: Impact on financials of obtaining capital funding

From these investigations it is clear that capital funding would be extremely beneficial to the project and, as expected, has a significant impact on project returns. Known local, regional and national scale funding options are included in Appendix B.

5.4.3. Discount on business rates

Many community groups have been successful in obtaining relief on business rates for renewables projects. Generally, Charitable rate relief does not apply to such projects, but many councils allow discretionary relief for non-profit or voluntary organisations. An investigation into the impact of rates relief is outlined in the table below.

Discount on business rates	**0%**	50%	100%
Y30 IRR	**7.0%**	7.2%	7.5%
Payback period	**12.4**	12.1	11.8

Table 14: Impact on financials of obtaining business rates relief

Locogen recommends discussing the project with the council to assess whether it would qualify for rates relief.

5.4.4. Sale price

Appendix D outlines the current options for sale of energy generated by the solar farm. This ultimately impace the sale value of the energy. The sensitivity of the project to sale price is outlined based on two likely revenue streams below.

Variability in SEG

Due to the variability in the current energy market, Locogen have investigated the sensitivity of the project to changing SEG rates. £45/MWh is considered to be reasonably conservative accounting for generally lower electricity values during peak summer daytime output. Following discussions with Sharenergy and The Client, Locogen have utilised a year one electricity value of £50/MWh for the base case assessment.

Table 15 below demonstrates how the expected returns change based on the achieved year 1 SEG. Please note that all other variables have remained the same.

SEG value (£/MWh)	45	**50**	55	60	65
Y30 IRR	5.7%	**7.0%**	8.2%	9.3%	10.4%
Payback period	14.1	**12.4**	11.1	10.1	9.2

Table 15: Impact on financials of obtaining variable SEG tariffs

The above table shows that there is a significant impact from a £5/MWh (0.5p/kWh) increase or decrease in achieved electricity value.

Increased value through Sleeved PPA

As set out in Appendix D there is an opportunity to consider a long-term sleeved PPA whereby a large consumer such as the Client could look to purchase the renewable electricity from the site through an intermediary energy supplier. In this instance, a price as low as c. £45/MWh (demonstrated above) may present a slight long-term saving to the consumer over market prices (noting that the intermediary supplier would be required to apply the necessary margin, use of network charges, etc.) which would bring the overall delivered price of electricity for the consumer roughly in line with typical market prices.

This analysis investigated the potential returns if MCLT are able to arrange for a sleeving Power Purchase Agreement (PPA) whereby electricity is sold, via an intermediary supplier, to a commercial consumer at a higher value than would have otherwise been secured through a merchant PPA. Generally, sleeved PPA projects are in the region of 10+ MW, however the community affiliation may appeal to the purchased and so this option has been considered.

PPA value (Y1) (£/MWh)	70	80	90	100	110
Y30 IRR	11.4%	13.5%	15.4%	17.3%	19.1%
Payback period	8.5	7.3	6.5	5.8	5.3

Table 16: Impact on financials of obtaining variable PPA values

It is recommended that the option of a sleeved PPA be explored by the Client through discussion with the energy supplier. This approach would reduce revenue uncertainty in the existing business case and may also facilitate the subsequent sourcing of finance to build out the project.

5.4.5. Variability in Rent £/acre

The Client provided a rental figure of £750/acre (£1,850 per hectare) per year. This is considered sufficient to include for compensation to the farmer for loss of earnings. Given the project's prospective affiliation with the council and that the council is the ultimate owner of this land, Locogen anticipate that rental figures could be considerably lower. As seen in the table below, the impact of changing the rent is marginal.

Rent	£550	£600	£650	**£750**	£800
Y30 IRR	7.2%	7.1%	7.1%	**7.0%**	6.9%
Payback period	12.2	12.2	12.3	**12.4**	12.5

Table 17: Impact on financials of amending the rental structure

5.5. Additional Sensitivities

5.5.1. Removal of development fees on all options

It is anticipated that 100% of development fees may be funded by the Stage 2 RCEF. This would apply to all costs in section 5.1.1. At the Client's request, Locogen have remodelled the financials for all projects with these costs removed. The outputs are illustrated in Table 17 below.

Project	**Option 1**	**Option 2**	**Option 3**	**Option 4**
1st year net annual generation (MWh)	6,366	6,366	1,273	1,035
Total project CAPEX	£5,553,000	£3,053,000	£1,600,700	£680,700
1st year gross revenue	£318,300	£318,300	£63,650	£51,750
1st year annual OPEX	£82,750	£82,750	£27,050	£27,050
1st year net revenue	£235,550	£235,550	£36,600	£24,700
Payback period (years)	21	12	no payback	24
20-year Net Present Value	-£2,147,128	£33,146	-£1,042,977	-£327,442
20-year Internal Rate of Return	-0.23%	5.13%	-5.42%	-1.88%
25-year Net Present Value	-£1,735,368	£440,779	-£968,032	-£280,235
25-year Internal Rate of Return	1.51%	6.45%	-2.77%	0.23%
30-year Net Present Value	-£1,393,090	£782,538	-£905,599	-£247,528

30-year Internal Rate of Return	2.60%	7.19%	-1.11%	1.35%
1st year CO_2 savings (tonnes)[4]	1,528	1,528	306	248

Table18: Financial assessment for the solar development options with development costs removed

As would be expected, this improves the financial case for all options.

5.5.2. Variability in CAPEX for all options

The Client requested a further investigation into the returns for the alternative project, should capital costs be partially grant funded. The table below outlines the impact of capital funding on all options, assuming that 100% of developments costs are already fully funded.

% capital funding		**0%**	**25%**	**50%**	**75%**
Option 1	Y30 IRR	**2.6%**	4.6%	8.1%	16.5%
	Payback period (years)	**20.5**	16.0	11.2	6.0
Option 2	Y30 IRR	**7.2%**	10.0%	15.1%	29.0%
	Payback period (years)	**12.2**	9.4	6.6	3.4
Option 3	Y30 IRR	**-1.1%**	0.5%	3.0%	8.7%
	Payback period (years)	**no payback**	no payback	19.5	10.4
Option 4	Y30 IRR	**1.4%**	3.2%	6.4%	14.1%
	Payback period (years)	**24.2**	18.8	12.9	6.7

Table 19: Impact on financials of obtaining capital funding

5.6. Consideration of debt finance

At the Client's request, Locogen have investigated the impact of debt financing as a means of funding the project. Generally, bringing in considerable (>50% loan to value) external funding requires a demonstratable basecase project IRR of at least 5-6% over 20 years to ensure sufficient security of loan/interest repayments and to minimise operational risk (e.g. during period when low electricity value or poor project technical performance).

Based on the above, Option 2 is the only scenario where there is considered to be the potential for external funding to be brought into the project and is therefore considered further below.

Historically the two routes available for debt are:

1. **Bank finance** – There are a number of 'high street' lenders (e.g. Triodos, Close Brothers, Santander) that have historically offered project finance for renewable energy projects. This means that the funder would take over the project should the repayments not be made. Typical terms for bank finance would depend on the amount being borrowed but for a project of this size would be as follows:

    a. Overall interest rates of c.4%;
    b. Loan terms of 15-18 years;
    c. Arrangement fees of c. 1.5-2.5% of the loan value (these would be added to the overall project cost);

[4] Assumes each kWh of electricity offsets 0.24kg of CO_2. Due to the assumed future decarbonisation of the electricity network this figure will reduce in future years.

d. Technical and legal due diligence fees of £60,000-£80,000 (added to the overall project cost); and
e. Annual loan management fees of £4,000-£6,000.

In addition to the above terms the banks would typically expect more conservative assumptions to be utilised around achieved generation and value for electricity. This, alongside a conservative debt service cover ratio used when calculating loan to value, would generally mean that the overall amount of loan secured for a project like this would be relatively low. For a project return such as set out by the Option 2 base case the total loan secured may only be 50-60% of the total capital cost, which would require c/£1.5m in equity to be provided and this would most likely need to be provided from a second loan which may be more challenging to secure if based on the more conseravtive loan requirements that these institutional lenders would require (and the fact that any secondary, or 'junior', loan would be ranked behind the main, or 'senior' loan when it comes to repayment.

2. **Community/Crowd funding** – This has proven a popular means of financing community owned renewable projects in recent years. It involves private individuals investing their own money into a project through share and/or bond offerings. This route has seen increased interest through a general desire by many individuals to support more 'ethical' investments, historically low interest rates (making advertised returns more attractive than those offered by traditional savings accounts) and higher uncertainty in financial markets. From discussion with Shareenergy it was noted that the terms are generally a lot more flexible than those that can be offered by banks, but that the attractiveness of the offering will directly impact upon the likely uptake (e.g. lower interest rates will mean less people are interested in investing). Typical terms for crowd financing that Sharenergy thought may attract a reasonable amount of public interest are as follows:

    a. A rate of return for lower risk bonds at 3% (on the basis that these investors would be repaid first of all);
    b. A higher rate of return of 4% for those securing shares (on the understanding that during poorly performing years they may not secure as much/any return);
    c. Loan term of 15-20 years;
    d. Less onerous and conservative financial assumptions used when assessing amount that can be borrowed;
    e. No arrangement fees but a cost to vet and set up the share offering of £40,000-60,000; and
    f. Annual loan management fees of £4,000-£10,000 depending on complexity of share arrangements.

    It should be noted that these investors are typically entering into these project with a fair degree of ongoing risk and it is critically important to ensure that the offering documents clearly set out the asusmptions and risks to avoid legal difficulties. This is where advice from experienced parties is vital to ensure this process is managed in a transparent and clear manner

Based on the above it has been concluded that community funding is likely to be the only route where significant (i.e. 90%+) funding would be secured for the project. An initial assessment has been provided below to allow an understanding of the impact of achieved returns once funding has been included and this is demonstrated in Table 18 below. This shows the impact on project funds that would be available for use by MCLT with two differing overall loan interest rates (assuming a mix of bonds and shares being offered). Within this model the following other terms have been utilised:

- A repayment period of 20 years;

- Average interest rates of 3.5% and 4.5% (for example the 3.5% opotion assumes the 'current' option of 50% of loan through a Bond @3% interest rate with remaining 50% through share offering @4% interest rate equivalent);
- 90% loan to value achieved (meaning 10% of CAPEX would still need to be found by MCLT);
- £4,000 per annum management fee (to be discussed with Shareneergy); and
- Conservaitve additional capital costs of £100k to account for costs for a third party to manage share/bond offerings and for additional works around business case.

Project reference		**Option 2a**	**Option 2b**
CAPEX (excl. development costs)		£3,155,026	
Total Loan amount		£2,801,700 (90%)	
Averaged interest rate		3.5%	4.5%
Distributable income to community (over whole 5 yr period)	Y1-Y5	£85,976	£0
	Y6-Y10	£238,043	£123,668
	Y11-Y15	£410,293	£343,933
	Y16-Y20	£491,733	£462,246
	Y21-Y25	£884,874	£885,370
	Y26-Y30	£1,375,252	£1,375,252

Table20: Impact of varying loan rates on project income (30 years) for Option 2

The above shows that there is the potential to realise good distributable community benefits through these projects if sufficient investment can be achieved at lower interest rates. It may become more challenging over the near future to secure good buy in to projects once UK wide inflation increases and interest rates inevitably increase. It is recommended that an early discussion take place with Sharenergy to talk through the above process in greater detail. They would also be able to provide introduction to active community solar projects where community funding has been a significant success.

6. Conclusions and next steps

6.1. Conclusions

Table 21 below provides a summary of the assessed risk for the main project considerations, prior to providing a summary of the overall assumed project risk. This assessment is based on the proposed development of the identified Rushmead Farm 5MW development (Option 2).

Issue	Risk	Considerations
Grid connection	High	The identified grid opportunities are limited, and costs are based on budget estimates and discussions alone. A detailed feasibility study from the DNO may reduce this risk, taking into account several additional grid studies and usually allowing for multiple options to be investigated. Furthermore, the grid cost for Option 2 is wholly dependent on the SGC project going ahead, and their associated risks therefore also impact this project. Should the Client wish to proceed with the project, and the collaboration with the SGC project is confirmed, it is recommended that a formal grid application is made as soon as possible. This is ultimately to minimise the potential for any remaining capacity in the wider network being lost to competing generation projects, and also to identify whether or not upstream reinforcement (or any significant network upgrades) are recognised at an early stage.
Planning	High	Based on an initial assessment there is the potential for sustained planning concerns from the Cotswolds Conservation Board regarding the AONB. Potential amenity and residential visual impacts have been mitigated where possible through avoidance of sensitive areas however this will likely remain a challenge in planning.
Construction & technical	Low	The location is on open agricultural land with an existing junction into the landowners property, which should lead to reasonably low construction costs for new access and infrastructure. The site is near to the M4 no obstacles apparent between this and the site (such as low bridges, waterways etc).
Resource & generation	Low	The initial solar resource estimate is considered to be reasonable based on the nature of the site and sourced operational information from other solar farms. There is a low risk that the achievable yield is significantly below that estimated in the base case assessment.
Financial	Medium-High	The base case project returns for the Option 2 project look reasonably attractive for the Client without the need for additional drivers for development. The grid connection cost is vital to the overall viability of the scheme and this highlights the importance of securing a realistic and cost-effective route to export generation. The sensitivity analysis shows the considerable positive impact from obtaining grant funding, which is potentially achievable for a community-led project (although perhaps not at the 50-75% level modelled in the sensitivity analysis). The capital and operational costs utilised in the model are estimated and further work is needed to finalise these. There is also a risk that higher business rates may be applied following the next valuation review and this would extend the payback of the project, although it is hoped that the Council will grant some level of business rates relief to the community. Finally, the financial returns are based on several assumptions in relation to future electricity costs. The sensitivity analysis demonstrates the drop in financial viability with a small reduction in assumed power price. It is vital for the project that a long-term route to market is identified.
H&S	Low	The proposed location is considered to present minimal possible construction and operational health and safety issues.

Overall risk	Medium - High	

Table 21: Risk register for the proposed solar development

The main risk for the 5MW, shared grid project at this stage is considered to be around the planning works and the grid connection. These items are largely dependent on the council's wider plans and the development risk of their parallel wind project. If the council project were not to go ahead, MCLT would have to carefully reconsider financials and funding routes to ensure a viable project could be realised.

Should the council project not go ahead, a commercial developer would likely look to maximise the grid connection opportunity and install a 10-20MW solar array. Sharenergy have highlighted two community driven solar schemes in Appendix F, Ray Valley Solar Farm (19MW) and Bretton Hall Solar Scheme (30MW), which are in development post subsidy. MCLT could approach the council to collaborate on such a project, as it is likely to have a lower planning risk compared with a wind and solar development. This could also realise the opportunity to access council funding routes.

6.2. Recommendations

The above document has set out the completed feasibility works for the two sites and identified a development that could achieve a potentially viable return. It is proposed that Locogen and the Client discuss the project to decide on the completion of further development works.

The proposed next steps for this assessment are listed below:

- Sharenergy to host workshop with Client to further discuss options for funding, timescales and strategy;
- MCLT to engage with council to determine the likelihood of progressing with a collaborative project & to gauge business rates relief options;
- If council collaboration is unlikely, MCLT to consider larger (10-20MW) solar project to maximise value of grid connection and take advantage of economies of scale;
- Request a detailed study from WPD South West for 20MW, 12MW and 5MW capacities;
- Revise financial models to include feedback from DNO and council;
- Engage with Cotswolds Conservation Board to determine likelihood of planning approval, and
- Proceed with community engagement and planning works.

Appendix A. Capital & Operational cost tolerances

The capital and operational cost tolerances for a 5MW project are outlined below and overleaf.

Cost item	Low-end	Utilised	High-end	Comment
Planning condition discharge	£7,500	£10,200	£35,000	Significant variation due to variation in works requested ahead of construction.
Surveys (topographical, services & ground investigation)	£7,500	£10,000	£15,000	Determined in planning.
Pre-construction PM (incl. procurement)	£20,000	£25,000	£30,000	Cost depends on agreed scope and provider.
EPC cost for installation	£2,200,000	£2,475,000	£3,000,000	
Grid connection	£500,000	£500,000	£3,000,000	Cost depends on potential to share grid costs with other renewable development on nearby land.
Construction PM (owner's engineer)	£10,000	£15,000	£30,000	Cost depends on agreed scope and provider.
Construction insurance and additional ad-hoc items	£10,000	£17,800	£50,000	
Total cost (excl. contingency)	**£2,755,000**	**£3,053,000**	**£6,160,000**	

Table 22: Estimated capital costs & tolerances for 5MW PV installation

Appendix A. Capital & Operational cost tolerances (contd.)

Cost item	Low-end	Utilised	High-end	Comment
Asset management fee	£5000	£5,500	£10,000	Costs can differ significantly depending on company size of selected provider and whether used to managing smaller PV sites.
Accounting and bookkeeping	£3,000	£4,000	£5,000	
Ongoing compliance works (monitoring and reporting)	£0	£1,500	£2,500	May be no requirement for compliance works, expectation is minimal ecological surveys/checks.
Metering and site consumption	£3,000	£3,900	£4,500	
Rent	£0	£0	£18,000	A fully commercial annual rental would typically be £800-900/acre. Loss of potential earnings would amount to less than half this amount.
O&M costs	£15,000	£22,000	£25,000	O&M scope can differ significantly and could secure cheaper rates but carrying higher risk.
Operational insurance	£6,000	£7,750	£10,000	Will differ depending on level of cover and history of claims.
Business rates	£0	£13,250	£30,000	As discussed in Section 5.4.3.
Inverter & panel replacement fund	£3,000	£4,600	£8,000	Will depend on assumptions used on replacement and assumed cost reduction over time
Total cost	**£35,000**	**£62,500**	**£113,000**	

Table 23: Estimated operational costs & tolerances for 5MW PV installation

Appendix B. Grant funding and loans

Currently, the UK government is incentivising the uptake of small-scale renewable energy installations through the Sustainable Export Guarantee (SEG). The SEG is administered by energy companies, who are able to set their own tariff rates. A list of SEG suppliers can be found on Ofgem's website. Regardless of this incentive, funding for capital costs is key to realising renewables projects, especially for community groups who tend not to have large cash reserves. Locogen has identified the following funding pots which the client may be eligible to apply to. This a non-exhaustive list, and further lists are available on the Community Energy England and Centre for Sustainable Energy websites.

Local grants

- **Caring for the Cotswolds:** Grants of up to £2,500 for community-led projects in the Cotswolds associated with environmental protection: https://www.cotswoldsaonb.org.uk/looking-after/caring-for-the-cotswolds/apply-for-funding/

- **Member Awarded Funding:** South Gloucestershire Council provides match funding to local community groups of up to £3,000 per ward: https://www.southglos.gov.uk/community-and-living/grants/community-grants/member-awarded-funding/

- **Gloucestershire Community Foundation:** Grants are offered to many different types of projects- although currently no renewable opportunities, there may be in the future: https://www.gloucestershirecf.org.uk/Pages/Category/our-grant-programmes

- **West of England Combined Authority LEP**: Several funding rounds to support economic recovery & growth: https://www.westofengland-ca.gov.uk/lep/lep-funding-and-projects/

- South Gloucestershire Council have stated an intention to set up a "**Green South Gloucestershire Fund**" which will receive contributions from developers, businesses and residents for investment in renewable energy projects, retrofitting projects, green infrastructure and habitat/biodiversity projects.

Large grants and loans suitable for group applications

- **Rural Community Energy Fund (Stage 2 funding):** Large grants (up to £100,000) for community projects development phase (including planning applications): https://www.gov.uk/guidance/rural-community-energy-fund

- **Reaching Communities England:** Large grants (minimum £10,000) for community projects: https://www.tnlcommunityfund.org.uk/funding/programmes/reaching-communities-england

- **Energy Redress Scheme**: Large grants (minimum £20,000) for charities conducting emissions reductions projects: https://energyredress.org.uk/apply-funding

- **People and communities:** Grants from £10,000 to £500,000 for community projects including systems and equipment: https://www.tnlcommunityfund.org.uk/funding/programmes/people-and-communities

- **Aviva Community Fund**: Grant of up to £50,000 available for community resilience projects: https://www.avivacommunityfund.co.uk/uploads/terms/aviva-community-fund-eligibility.pdf

- **Social and Sustainable Fund:** Loans of £250,000+ for community projects including those addressing fuel poverty and energy efficiency: https://www.socialandsustainable.com/community-investment-fund/

Other grants and loans

- **The National Lottery Awards for All:** Grants £300 and £10,000 for community projects: https://www.tnlcommunityfund.org.uk/funding/programmes/national-lottery-awards-for-all-england

- **Tesco Bags of Help**: Small grants for community projects including environmental improvements: https://tescobagsofhelp.org.uk/home/community-apply-bags-help-grant/

- **Sureserve Foundation Community awards:** Grants of up to £5,000 for community projects that enhance energy efficiency and/or combat fuel poverty: https://www.thesureservefoundation.org/

While few of these grant sources are likely to provide a significant proportion of the costs of setting up a solar farm, they might make a contribution to aspects of the scheme such as contributing toward the cost of enhancement opportunities (as discussed in Section 2.1.11).

Additional funding routes

In addition to the above, there are more traditional funding routes, outlined below.

1. **Non-recourse bank funding** – Securing a loan from a bank to build a solar project (where the solar project is the security) is a common route for raising a significant proportion of the equity to build a project. Banks are typically risk-averse and there are several steps put in place to ensure that the project is able to repay this loan over the life of the project:
    a. First of all, the bank will typically undergo detailed technical, legal and financial due diligence on a project which can exceed £100,000 and would be payable by the Community Group. In addition, there may be arrangement fees to pay of circa 2% as well as ongoing bank 'management fees' throughout the term of the loan.
    b. Subsidy-free projects do have significantly higher revenue uncertainty when compared to projects that previously were able to secure incentives. The funding available will therefore likely be fixed on a low estimate of future revenue to be conservative. This, along with the typical use of the P90 energy yield (equivalent to the statistical worst generation year in 10 – equal to the probability of being exceeded 90% of the time) means that the achievable yield and revenue assumed by bank models may be below the base case model. This in turn may reduce the loan to value amount that could be secured and require additional funding or equity to be put in the project by the Community Group.
    c. Typically, we would expect solar projects with base case unlevered returns of 7% or above to be able to secure reasonable levels of bank finance. Typical loans may look for 4% interest and have a 20-year term.
    d. The Community Group could look to reduce the revenue uncertainty by agreeing to purchase the electricity generated through a sleeved PPA or similar arrangement as set out in Appendix C.

2. **Peer to Peer (P2P) funding or crowdfunding** – This is an increasingly popular approach to take for renewable developments and has been supported through increased attention on people looking to make ethical investments and some changes to tax incentives and regulations (e.g. allowing lending through ISA scheme). Typically, individuals will loan money to a project and receive interest and the original money back when the loan is repaid. There are a number of parties that manage P2P lending for

renewable projects including Triodos[5] and Abundance[6]. These parties will generally accept higher risk projects than the 'high street' banks, but they may require higher returns on their loan to be of interest. In addition, the management fees from the parties that offer this platform can be significant. With regards to raising funds from the community or general public, there are no examples projects known to the team where this has been successful.

There are a number of platforms that encourage and arrange for investment in schemes such as Community Energy. One of these is Abundance. Abundance were involved in the Resilience 0.5MW wind project in the Forest of Dean in 2014[7] but their more recent case studies all seem to be much larger schemes such as the Orbital Marine Project in Orkney[8].

Such schemes tend to have fairly high costs for the investment that they raise, specifically the management fees associated with raising the finance. These higher costs were viable when the Feed in Tariff (FiT) was offered by the government, and might work for more entrepreneurial schemes such as Orkney Marine but smaller Community Energy schemes would struggle to pay them in the post-FiT situation.

Projects such as Energy Local (discussed subsequently) may have received innovation funding, which is often available for community projects. However, as many of these models are now becoming more established, innovation funding becomes increasingly less available for similar schemes. The challenge for these 'sandboxed' projects is now to make the Energy Local model work commercially *without* grant funding.

These options can be discussed further but is important to have a clear understanding of how the project could be funded, and what the cost of the funding will likely be, to ensure that this is a worthwhile proposition.

Partnering opportunities

MCLT raised the matter of partnering with a support organisation, whereby the financial aspects of the project could be managed on their behalf. Sharenergy[9] offer an operations service that covers all these items at a reasonable annual fee. Bright Renewables[10] also offer a similar service, as do Energy4All[11]. Energy4All's model is slightly different to the other two as the schemes are considered as members of Energy4All rather than clients.

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[5] https://www.triodoscrowdfunding.co.uk

[6] https://www.abundanceinvestment.com

[7] https://medium.abundanceinvestment.com/community-energy-and-farmers-a-recipe-for-renewables-success-60378bbc36e

[8] https://medium.abundanceinvestment.com/meet-the-developer-orbital-marine-power-orkney-7331659cb8dc

[9] https://www.sharenergy.coop/services

[10] https://brightrenewables.co.uk

[11] https://energy4all.co.uk

Appendix C. Operation & Governance

This appendix provides some insight into the means by which Community Groups such as MCLT may operate in the energy market.

Ownership models

The ownership models that are available to this project can be summarised as follows:

1. **Develop, own and operate** – This option would require the Community Group to take on full development and construction risk but also benefit from the full project returns available. This also gives the Community Group complete control over how the project is progressed and ultimately funded (as discussed later in this section).
2. **Pass project to third party to develop, own and operate** – This option means that there is no development cost risk associated with the project and is favoured where the development process is seen as being beyond the Client's comfortable level of risk or being too far from their 'core business'. Renewable energy development is complicated and there is the potential for this project to spend c. £200,000 in development without any positive outcome. In this instance, the Client could look to pass the project to a commercial developer and define terms for land rental (commercial rental rates would exceed £100,000 per annum) and/or define a requirement to sell the power at an agreed rate to the Community Group once operational. However, it is unlikely that this project (given it's relatively small scale from a commercial perspective, teamed with high connection costs) would be attractive to a third party developer.
3. **Establish a joint venture** – MCLT could propose the project to a commercial developer or partner and develop the site as a joint venture (JV). The terms of such would be agreed between both parties with regards to apportionment of ownership and operative responsibilities.

Assuming MCLT were to continue to develop, own and operate the project, the group may consider setting up a separate company specifically for the energy project. Below is an outline of community group structures and each one's suitability for the solar project.

Community group structures

Community Benefit Societies

Most Community Energy ownership schemes are arranged as a Community Benefit Society (CBS). A CBS is a form of co-operative but the financial benefit accrues to the community not to the members. The members can be paid interest on their investment in the CBS but only at a level required to raise the capital. These rates were around 5% when the Feed in Tariff (FiT) was operating, but they are now more commonly around 3% post-FiT. If the CBS has a good year, it could decide not to pay a higher interest rate, and any surplus would be used to re-pay capital or go to the Community Benefit Fund. Marshfield Community Land Trust are already a registered Community Benefit Society so could run the solar project as a scheme within the Land Trust, or it could decide to set up a separate CBS specifically for the solar project. Having a separate CBS would add to the costs and administration, there would need to be a board, annual accounts, an AGM etc, but it would remove any risk to the Land Trust if the solar project ran into difficulties.

Anyone who buys shares in a CBS becomes a member of the society, with one member one vote, regardless of the number of shares owned. There is a legal maximum of £100,000 per shareholder, the minimum is set by the CBS. Having a low minimum encourages those with limited means to take part but increases the administrative burden.

The interest rate expected from the scheme would need to be outlined in the share offer document, along with an appraisal of the risks that might affect the ability of the CBS to pay those rates, e.g. increased installation costs, maintenance issues or low electricity prices on a PPA. Sometimes a CBS finds it cannot pay interest in the first few years – this is normally compensated for by slightly higher interest rates in later years.

Community Energy shares are generally a long-term investment, they are not suitable for anyone looking for a quick return on their capital. Shareholders can request to have their capital repaid if they need to, but there is no requirement on the CBS to agree to such a request. However, it is generally in the CBS's interest to re-pay the capital invested as soon as possible, thus reducing the debt burden in future years. At each AGM the CBS will decide on what interest rate it can afford and how much capital to re-pay. This capital re-payment could be taken up by individuals who've requested to have their money back or it could be spread across the membership.

A CBS can also raise money through bonds. Bonds have an agreed interest rate and capital repayment schedule and are often for shorter terms than shares, typically ten years. They therefore offer less flexibility to the CBS than issuing shares, but they can appeal to people who are more risk-averse or are looking to invest over a shorter time frame. Bonds are often used as a secondary fund raiser, sometimes for repaying existing temporary loans. Bondholders are not members of the society, unless they also own shares.

Charities

Charities can own renewable energy assets and can raise grants that might not be available to other types of organisation, but they cannot sell shares. Charities can raise money through Charitable Bonds without setting up a CBS, but the bondholders are not members of the charity in the way that shareholders are with a CBS. Charitable Bonds until recently have mostly been arranged by larger charities but Big Society Capital have launched a scheme to help smaller charities take up this option.[12] It is harder to set up a charity than a CBS and the reporting regime is stricter, this route would normally only be taken by organisations that are already a charity that don't want to set up a separate CBS.

Energy Supply Company or Energy Services Company

One unconventional structure may be for the Community group to setup and an Energy Supply Company (ESC) or Energy Services Company (ESCo). Generally, an ESC will buy electricity from the grid and sell this electricity to its customers, however they can also own renewable assets and include this in the sale mix. Alternatively, an ESCo will usually sell heat or electricity as a service, and can also own the heat and power assets in a property.

For example, ONECarluke is the local development trust in Carluke, a town of 14,000 in south-west Scotland. ONECarluke is setting up an Energy Services Company (ESCo) and building local support for an energy club. The energy club will install solar PV and batteries on the rooftops of local homes and businesses, and then supply that electricity to club members, providing a discount on electricity costs, and generating income for the community. This depends on monitoring of generation and loads, made possible by the ZUoS Communities Platform. A number of local businesses have committed to participate in an initial pilot, to be installed by March 2022, with the ambition to scale the project across the whole town over the coming years.

The energy club ensures an inclusive net-zero transition – membership will be open to all, so everyone can benefit. ZUoS Communities is the user interface which will provide the ESCo with

[12] https://bigsocietycapital.com/portfolio/charity-bond-support-fund/

energy and carbon insights, and the club members with details of energy usage, costs, and carbon savings.

This however is seen to be a very challenging route for a project such as the 5MW scheme proposed here. Operating as a community ESC/ESCo may require several ongoing job roles, and many community groups find it difficult to maintain sufficient organisational capacity throughout a project's lifetime, especially with regards to legal advice, technical skills and administrative responsibilities. Furthermore, the community ESC/ESCo would be subject to risks that larger companies (such as the big six) can overcome with capital.

Nevertheless, there are several community led ESC/ESCos in the UK. A detailed study on their challenges (though with a weighting on heat as a service) was completed as part of the MPP Capstone Project at the University of Edinburgh[13].

13 https://static1.squarespace.com/static/536b92d8e4b0750dff7e241c/t/56c1e81b27d4bd75b2db1aaa/1455548450999/Challenges+facing+Community-ESCos+in+the+UK.pdf

Appendix D. Revenue streams

New renewable energy projects can no longer benefit from Renewable Obligation (RO) or Feed-in-Tariff (FiT) subsidies, which are a crucial revenue stream for many existing schemes to achieve a workable financial return. Although technologies have become more efficient and cost effective in the interim, developers, whether private or community led, do need to look for means of maximising the value of generation to achieve viable revenue streams.

The proceeding sections discuss the various revenue streams available to renewable energy projects. As well as conventional revenue streams available such as export Power Purchase Agreements (PPAs) this section also discusses other potential revenue streams available, such as grid balancing services, and comments on their applicability to technology type and scale.

For the majority of commercial scale renewable energy project, a grid connection with sufficient export capacity will be vital for the viability of a renewable generation project. The exception is if a private wire is connected to a sufficiently large load, a *Private wire* PPA, which is discussed subsequently. A connection to the grid is also a requirement if a project is to take advantage of any grid balancing services.

1. SEG

Since Feed-in Tariffs for solar PV were closed, the Government announced that owners of electricity generating equipment, including solar PV, could make agreements with licensed electricity suppliers for the payment of electricity exported back to the grid. These agreements, known as Smart Export Guarantees (SEGs) are made between the owner of the generating plant and an electricity supplier and the details of guarantee (including the amount of money received and the length of the contract) will be determined by the supplier.

In addition to this, some suppliers are now starting to offer variable 'agile' export tariffs, which don't give a guaranteed price per kWh for every unit exported back to the grid, but which vary this rate alongside half-hourly wholesale rates such that the rates received for exporting back to the grid are maximised. This works particularly well where batteries are installed, such that the energy generated can be reserved or 'held back' from the grid until the times where export payments are at their highest.

2. PPAs

A PPA is a long-term electricity supply agreement between a generator and a purchaser. PPAs are frequently sought by large consumers of power to secure a long-term secure supply at an agreeable price. Different types of PPA exist which can be via a physical connection or virtual connection. These are considered below.

2.1. Utility PPA

A utility (or 'off-site') PPA is the export of electricity onto the local distribution or transmission network and there is therefore no requirement for the generator to be located close to the end consumer. The average price for a utility export PPA export is typically £35-55/MWh although shorter fixed-term PPAs can often achieve better prices. For example, in 2021 solar developments have secured rates in excess of £90/MWh for fixed three-year rates, and c. £110/MWh for a one year co. Projects that are able to secure 1-year PPA contracts generally can secure the best rates if they have a good PPA procurement policy that renews when market prices are high. Larger commercial projects have historically had to secure longer term PPAs of 10-15 years to satisfy banks (where there is deemed to be a risk of no offtaker being secured for sale of electricity in later years). For these longer term PPAs, the prices are often fixed for the first 1-2 years and then move over to an inter-day electricity price index which is generally not as attractive as forward selling for fixed rates when market prices are high.

2.2. Private wire PPA

Rather than exporting all generated power to the grid as discussed above, another PPA option is a private wire connection to supply a local consumer.

Increasingly, more new renewable energy projects are seeking private wire arrangements with large consumers of energy. Such agreements are mutually beneficial for the generator and the consumer and can therefore be driven by either party. The consumer can avoid distribution and transmission costs that are passed on by the utility energy supplier by connecting to a private wire and the generator can therefore negotiate a selling price that is lower than that from the utility and above the wholesale market price.

A private wire PPA offers direct control of energy supply and purchase and makes customer relations more efficient. The generator can also still be connected to the grid for export when onsite demands from the consumer is too low. Achieving a grid connection agreement is also made easier in such circumstances as the maximum export is often greatly reduced. A potential risk of arranging a private wire PPA is the assurance that demand and generation will remain over the lifetime of the contract. If the consumer is a factory for example which closes down, then the generator will no longer have its main export route. Figure 20 below shows a schematic of a generic private wire PPA arrangement.

Consumers with a consistent base load and high energy demand are well suited to private wire schemes with intermittent renewables. This is because any time that power is being generated, the project wants to be able to send it to the consumer to maximise income from the higher purchase price of power compared to grid export. The consumer would want to maximise the amount of electricity received via the private wire to lower bills and carbon emissions from their activities. In rural areas large consumers could include, for example, agriculture, distilleries and aquaculture.

Private wire PPAs offer greater revenue per unit of power exported compared to utility PPAs, with average prices of £70-100/MWh. Negotiating a price depends on the consumer's drivers, demands and other supply options.

Solar technologies generally have an advantage for private wire PPA schemes because there are more opportunities where these can be deployed on adjacent land to the consumer (from a purely resource perspective, not accounting for planning considerations). The Marshfield site has already been identified, therefore it would be idea for a large/significant consumer to be located nearby.

The distance to the consumer will be dependent on the size of generation system; the consumer's load, and complexity of cable route. For a 5MW project, an indicative benchmark of 5km between the generation substation and consumer could be used as a maximum distance when assessing sites. The closer the distance, the lower the cabling infrastructure cost and the less the cable losses.

Normal direct wire connections are to one property. There are two ways to connect to more than one property;

1. By splitting the array so part of the site supplies one building, other parts serve different buildings. This has been done by Pomona Solar Coop[14] in Herefordshire where the array feeds several small industrial units. The disadvantage of this approach is that the amount delivered to each unit is limited by the proportion of the site it is connected to.

[14] see http://pomonasolar.org.uk/

2. By creating a microgrid whereby all the electricity for several buildings comes from one main grid connected meter, with all other buildings operating on sub meters. This gets over the limitation problem of the split system but requires that all the buildings are reliant on the scheme for all their electricity, thus they lose their ability to switch suppliers and it can be awkward to re-connect to the national grid if someone wants to opt out of the microgrid.
   One possibility is to keep the national grid meter for lighting only and connect the power meter to the microgrid. This makes it easier to opt out of the microgrid, however the buildings then still have to pay a standing charge on their main grid meter. It does not seem to be worthwhile creating a microgrid for a solar installation, as the amount of each building's electricity demand the solar could fulfil would be low. If there was wind power available, or a mixture of renewables and energy storage then a microgrid might be worth considering.

Unfortunately, at this time there does not appear to be a sufficiently large consumer locally that could benefit from a private wire to the MCLT solar array.

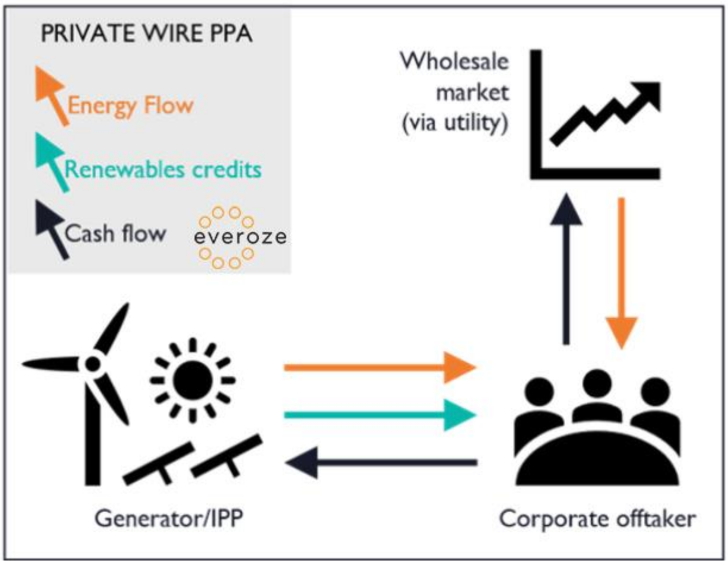

Figure 20: Private wire PPA schematic[15]

Urban Chain and F&S Energy

The main benefit of a direct wire arrangement is that the purchaser does not have to pay the additional charges levied for using the national grid (use of system charges) or the additional levies such as those to pay for the Feed in Tariff (FiT) or the Climate Change Levy (CCL).

Urban Chain and F&S energy have both been working on schemes whereby the purchaser avoids these charges even though there is no direct wire connection to the renewable assets. We are uncertain what future these schemes have, but we imagine that Ofgem will want to close such loopholes, otherwise the use of system charges and other levies will fall disproportionally on those purchasers who do not have such an arrangement.

[15] Everoze Partners Limited 2020: https://everoze.com/ppa-models/

2.3. Sleeved PPA

A sleeved PPA is very similar to the utility PPA in that the power generated will be exported to the grid and the end consumer will then import from the grid. However, there is a PPA agreement and price in place between the generator and consumer. A third-party supplier such as an energy service provider acts as an intermediary between the generator and consumer by taking the power generated and 'sleeving' it to the consumer at its point of consumption. The intermediary party will then claim a fee for facilitating the transaction. Figure 22 shows a schematic of a sleeved PPA set-up.

A sleeved PPA agreement can be useful for acquiring a higher selling price where a local private wire connection is not possible. However, transmission and distribution charges cannot be avoided, and the supplier would still secure their mark up on the generation. Sleeved PPAs are therefore less financially attractive than private wire PPAs in the majority of cases. The exception being if the capital costs for installing the private wire PPA are prohibitively expensive. A sleeved PPA service does however can reduce the revenue uncertainty by locking in a fixed rate for some or all of the power over the duration of the PPA.

Historically sleeved PPAs have been secured between large commercial generators and multinational companies. However, an increasing number of intermediary energy services providers are looking to offer sleeved PPA contracts for smaller commercial scale projects.

The price received for export in a PPA arrangement is similar, or sometimes even less initially, than the export price achieved under a utility PPA. Average prices are typically £40-55/MWh. The benefit over utility PPAs however is the potential to agree a longer contract with set pricing so that there is greater certainty on longer term revenue. This is illustrated in Figure 21 below which is based on a 15 year PPA contract (annual revenues therefore revert to market rates at this point).

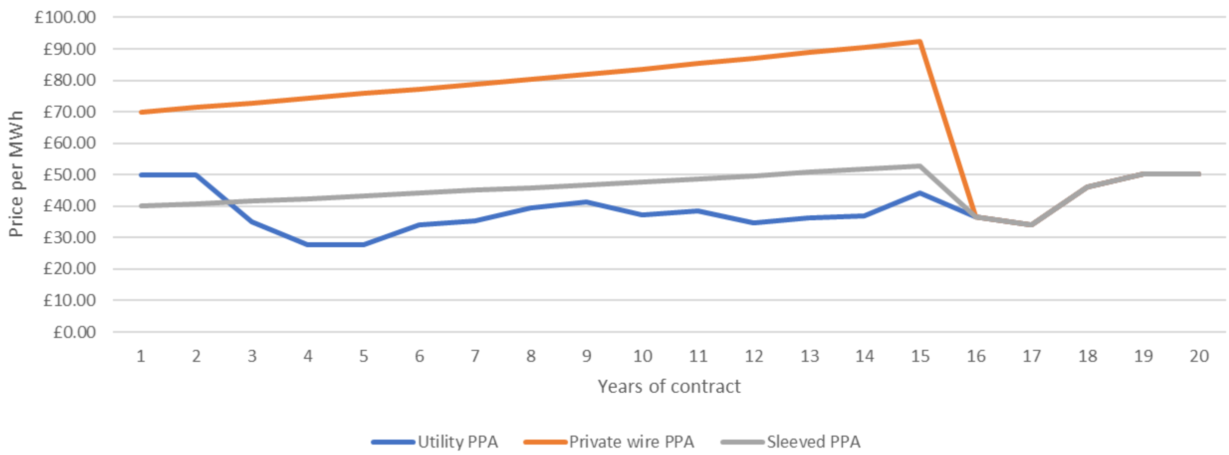

Figure 21: PPA comparison with 15-year contract

A sleeved PPA may be considered to be a viable option and in this case the Council could be a suitable consumer. No existing opportunities for a private wire PPA were identified and therefore it is likely that a sleeved PPA would offer a more financially viable route to market.

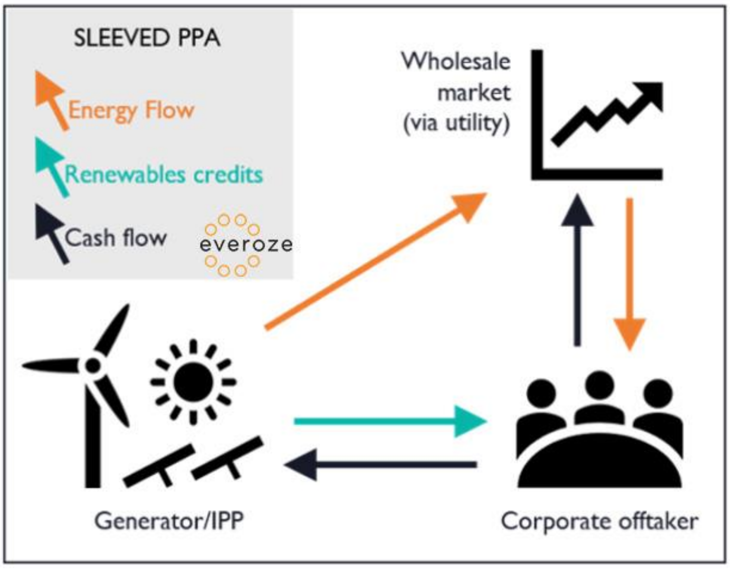

Figure 22: Sleeved PPA schematic[15]

MCLT would need to identify and approach a potential sleeved PPA customer to buy the electricity generated by the solar. One option may be to sell the energy to South Gloucester Council, to be distributed across their assets and contribute to their renewables targets. It should be noted that, should a commercial or public body act as the consumer of the energy, the project carbon accounting would likely benefit the consumer and not offset the consumption of Marshfield Village.

Several community projects have identified potential sleeved PPA customers via the Renewables Exchange[16], created specifically to link renewable generators up with offtakers.

Alternatively, Peer to peer (P2P) trading is similar to a sleeved PPA however consumers can purchase power from multiple generators rather than being reliant on a single one. A licensed supplier (such as Octopus or Bulb) is required as an intermediary between generator and consumer. P2P mainly benefits the consumer as they can pick and choose the best prices for their energy. However, P2P does offer an alternative route to market for generators and community owned projects may be offered a better price than a fixed PPA.

2.4. Virtual PPA

Virtual (also known as synthetic) PPAs decouple power and financial flow. In a similar way to other PPAs, generators and consumers agree an electricity price. However, a third-party intermediary, such as an energy service trader and/or provider, will trade the generated power on the generator's behalf on the wholesale market The consumer will then receive the electricity from the grid that was exported by the generator.

Virtual PPAs can operate using a contracts for difference model which involves the generator and consumer agreeing a strike price. The respective PPA partners will compensate one another so that the agreed PPA price is paid as the market price varies above and below over the course of a year (or other defined time period).

A major benefit of virtual PPAs is the simple contracting arrangements between the generator and consumer, which can be particularly important for community groups with limited internal

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16 https://www.renewableexchange.co.uk/

resource and funding. Virtual PPAs allow a multi-buyer model to operate meaning it is far more flexible than the other PPA options. The structure is more complex than other PPAs, as shown by Figure 23.

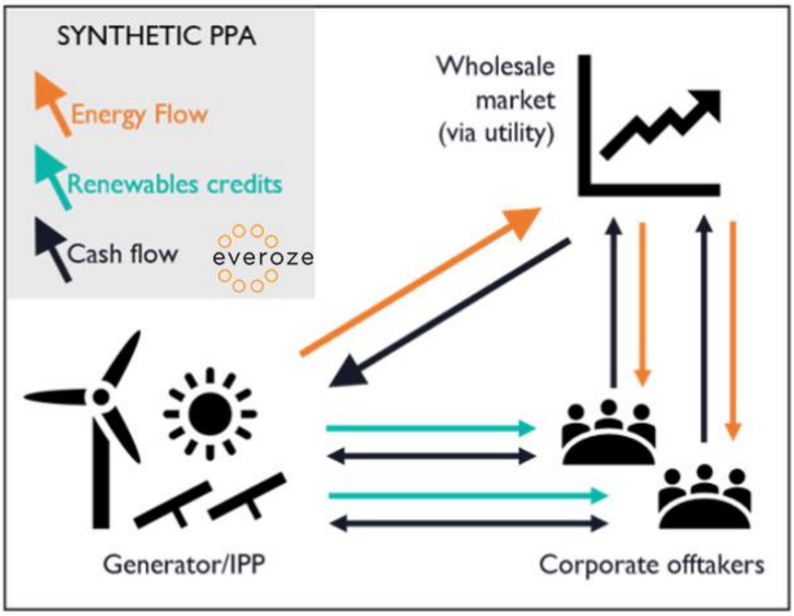

Figure 23: Virtual PPA schematic[15]

2.5. PPA options applicable to Marshfield

The Marshfield project would most benefit from a sleeved PPA that provides price certainty over a sustained period of 10-20 years which would be beneficial for reducing revenue risk for funders/investors. The key limitation to this approach is that the project is relatively small and may not be considered large enough in generation terms to justify an attractive long term rate.

The alternative option, albeit a higher risk one, is to maximise the potential revenue upside by re-negotiating short term (i.e. 1 year) merchant PPA contracts when pricing is high. The disadvantage of this approach is that, without any floor price, there is a risk that sustained periods of low electricity pricing may lead to project securing a short term PPA that is well below the modelled average of say £50/MWh. Pricing was very low at the start of the Covid pandemic and rates of £40-45/MWh were being secured by some generators.

Before a site becomes operational a developer can typically secure a PPA 6-9 months before the estimated commissioning date (albeit they may carry some risk if the project commissioning is delayed substantially as the supplier is expecting the generation to be available. Once operational the available time period in advance of a PPA renewal will differ between suppliers. Smaller suppliers will generally not secure new PPA contracts that are >6 months away from renewal, whilst larger suppliers will often look to agree PPA rates for periods that are 12-24 months in the future.

The current electricity market is a good example of where ongoing short term contracts are beneficial. Rates have been locked in >£90/MWh for the next 12 months and some are securing 2023 and 2024 PPA deals with large suppliers that are still comfortably above the expected export guarantee rate of c. £55/MWh.

Ultimately the approach that is ultimately taken will likely be dictated by any funder/investors. Large high street banks for example that provide project finance have typically pushed developers to secure PPA rates that cover the full length of the repayment period but only at a tracker rate beyind year 2 that was well below those being secured by short period PPAs.

3. Energy Local Model and impact of the Local Electricity Bill

The Energy Local[17] model was started in Bethesda in North Wales where a hydro scheme has been operating for several years. The community have an arrangement with Octopus energy that allows local Octopus customers to get cheaper electricity when the hydro is operating. The hydro operators also get slightly more for the electricity generated if it is used locally.

The Energy Local model is the basis for the Local Electricity Bill which is currently going through Parliament. The Local Electricity Bill is however rather vague, simply stating that suppliers should enable and encourage such schemes.

There are a handful of other communities now taking up the Energy Local model but Octopus have stressed that the Energy Local scheme they are running is a trial and they are not committed to continuing it indefinitely or offering it to other places around the UK. This model is of interest to the community, but it would be difficult to build it into a business model with any degree of confidence.

Local Energy Systems are an emerging market with several pilot trials taking place across the UK. Due to the immature nature of the technology and regulatory barriers to commercial deployment, many of these pilot projects are receiving grant funding from UK Government through the Department for Business Energy and Industrial Strategy. One such example is the Power Forward Challenge, which has funded 8 pilot projects to develop innovative solutions that address the challenges of decarbonising the grid. Locogen were successful in gaining grant funding from the Power Forward Challenge to develop our ZUoS solution. ZUoS is an energy services platform that provides energy optimisation through a Zonal Use of System software control system, incentivising local energy matching.

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[17] https://energylocal.org.uk/guide1

Appendix E. Battery Storage Opportunity

1. Background & Technology

Following the feedback from the local DNOs, Locogen investigated alternative routes for income from energy storage. If the SGC project were not to go ahead, the solar project (base case) at 5MW is unlikely to be financially viable given the large cost of the grid connection. However, this opens up an opportunity for the community group to install additional capacity, in the form of more solar PV (which we strongly recommend) and/or energy storage. For example, 5MW solar + a 5MW battery would (in most cases) require a connection capable of exporting 10MW of generation.

Essentially, while the DNO can inform whether or not a connection of 10MW is possible and how much it would cost, they do not have the capacity to inform whether energy storage will be beneficial to the national grid, but rather can advise on the usefulness to the distribution grid. Generally, there appears to be a dissociation between National Grid and the DNOs where storage is addressed. There are several independent companies facilitating energy storage development in order to provide grid balancing services to the transmission system operator (TSO), National Grid, and it appears the extent of their involvement with DNOs is limited to securing export and import capacity. These are known as TSO balancing services.

Beyond providing capacity, National Grid has a statutory obligation to maintain the frequency of the national transmission system between 49.5 and 50.5Hz (±1% of 50Hz). The frequency fluctuates continuously as demand and generation vary. If demand increases above generation, the frequency of the transmission system will fall and vice versa. National Grid must therefore ensure that generation and/or demand are kept in reserve to provide maximum security of supply. Different means of offering grid balancing services, and the associated potential additional revenue streams, are outlined in Section 2 of this appendix.

1.1. Battery Technology

S*hort-duration* battery storage are the most prevalent in the energy market today, due to a number of factors, including the availability and value of frequency-based grid balancing services (i.e. millisecond response to deviations in grid frequency for short durations). The market leading battery technology is lithium-ion based, with a charge cycle of 1 hour (i.e. 1MW:1MWh batteries), which are suited to the provision of grid balancing services and deferring solar export. Given evolving market dynamics, there is early-stage activity into designing these systems to offer 1.25 – 2 hours duration (i.e. 1MW:2MWh). There are various types of lithium batteries, but the most common is LFP (lithium iron phosphate) and NMC (Lithium-Nickel-Manganese-Cobalt-Oxide). Each have their own benefits. There are numerous Li-on battery manufacturers, including BYD, LGChem, Tesla and many more. The CAPEX costs for a 1-hour (1MW:1MWh) lithium-ion based battery system is in the region of £350,000 - 400,000/MW. The price increases for a 1.5 hour and 2-hour system.

Long-duration storage technologies do exist but are at present not yet widely used due to a number of factors including financial feasibility. Example of such include Flow batteries, from manufacturers such as Invinity and Cellcube, which specialise in vanadium redox flow batteries (VRFB) and new manufacturer StorTera offering a single liquid flow battery. These could be used for frequency response services due to their rapid ramp rate, but are also suited well to value streams that require longer charge and discharge cycles, for example energy markets (i.e. day ahead and intraday trading). Long duration storage batteries can offer longer charge and discharge cycles of between 4 – 12 hours. Long duration storage technology are approximately 2-3 times the price of short-duration lithium-ion based systems and are priced on a per MWh basis. Given this they are not considered further in this study.

Locogen have assumed a 1-hour duration battery is deemed to be a reasonable level of response for the current market. During the specification phase this may change dependant on further consultation with aggregators and manufacturers and this could impact costs. We could look into modular systems, should the opportunity for longer duration systems become more viable in the future.

1.2. Layout & Ancillaries

Battery sites are generally modular and consist of a number of battery units. Similar to solar, PV arrays, these battery units are connected to inverters which convert DC electricity from the batteries to AC electricity for the grid (and vice versa) and subsequently transformers which increase the voltage (usually c. 600V) to grid voltage (for >1MW sites, this is upwards of 11kV). The inverters and transformers are often housed in a single on-site substation. In addition to this there will be cabling to connect the system; security fencing (and often security cameras), and lighting.

For illustrative purposes, a 9MW/9MWh battery site is shown below. The site footprint is c. 800m^2. Each battery unit (B) has a capacity of 1MWh, which exports via a 1MVA inverter (i). In this example, every three inverters are linked to a transformer (T). There is also the site substation compound (ss) which hosts grid connection and controls (though may also house transformer in some configurations). All is contained within a security fence, with ample lighting and parking.

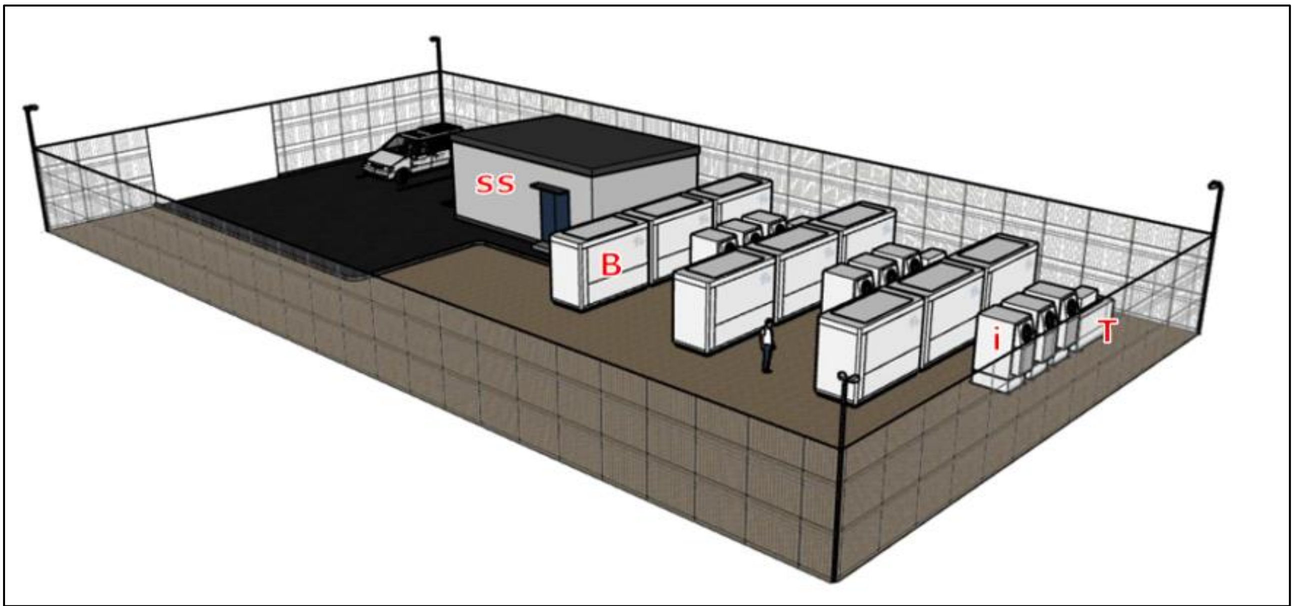

Figure 24: Example utility-scale energy storage site layout (9MW) from Multi Source Power

One example of a site where battery has been co-located with solar (at a scale of interest) would be Gridserve's site at Clayhill (MK45 5JD, developed by Anesco). This is a stand-alone 10MW solar PV installation with 6MW of battery storage. The battery storage can be seen from satellite imagery.

1.3. Battery Degradation

A key consideration for batteries is the number of cycles (one cycle is a full charge and discharge of the battery) per day. There is a direct correlation between battery cycles and degradation (the more cycles, the more quickly the battery degrades). For example, optimising the battery ~5-6 cycles per day would degrade the battery more quickly (~5 years), impacting the payback. A ballpark battery lifetime of 10 years would equate to ~2-3 cycles per day. Manufacturers provide a warranty based on cycles per day and this can range from 1-5 (the higher the cycles, the more extra costs on the warranty). The £/MW/year revenues (provided in Section 2 of this appendix) are based on 2 cycles per day.

1.4. Indicative costs

Table 22 below illustrates the estimated development, capital and operational costs associated with a 5MW battery in addition to the solar project. The following should be noted:

- The development costs include for additional planning and technical support, but do not include the costs associated with the grid connection, which should be derived from the cost for a 5-12MW connection in Section 3 of the report. Similarly, the capital costs include for the unit, ancillaries and installation, but not the grid connection works.
- The operational expenditure includes for O&M, accounting, and Balance of Plant electrical (HV) maintenance and insurance. It is possible that this cost could be reduced for a combined solar & storage project. The Client should add to this OPEX a land rental amount, which for storage is often in the region of £1,000/MW for commercial storage projects (though is anticipated to be less for a community-led project on council land).
- Locogen have not included business rates as this project is community led and is therefore likely to be exempt. These can be added to OPEX if required.
- The Client may also want to consider battery replacement cost, spread over a conservative 10 year lifetime of the battery equipment. Note that in 10 years, battery prices may drop considerably.

Cost Item	**Estimate cost**
Development costs	£35,000
Capital costs	£2,055,000
Estimated total cost	£2,090,000
Total upfront cost (incl. 10% contingency)	**£2,299,000**
Operational costs	£59,558
Total operational cost (incl. 10% contingency)	**£65,514**

Table 24: High level indicative costs for 5MW battery project at Marshfield

2. Current value streams

A battery can be optimised across a range of value streams to generate revenue. Those that are currently considered to be most relevant are described in this section. These have been organised into five broad 'categories' as listed in Table 25 below. Based on discussions with various stakeholders, recent consultancy studies, and research for our own development's projects, Locogen have made a high-level estimate of the value that can be gained from each, and the likely future trend. Please note that the value indicated is not cumulative (i.e. an asset cannot be used in each value stream simultaneously) and there are barriers to entry for each (i.e. satisfying National Grids requirements to enter into Ancillary Services).

Value Stream	Summary	Estimated Value[18] (£/MW/yr)	Future Value trend
Energy markets	Given the increasing penetration of distributed power and renewables, the volatility in these markets is increasing, which will lead to greater value opportunities. This includes the day-ahead and intra-day energy markets.	~£10,000 – £20,000	↗
Balancing Mechanism	The electricity market is settled (i.e. supply = demand) every 30 minutes. During what is known as each 'settlement period' the TSO uses the Balancing Mechanism (BM) to instruct assets to increase or decrease their generation or consumption to ensure a balance between supply and demand. The BM is receiving increased attention by market stakeholders due to the value opportunity it currently offers and will offer going forward as the market becomes more volatile. This value stream has only recently opened to distributed assets.	~£10,000 – £20,000	↗
Ancillary Services	There are a range of ancillary (or balancing) services that the TSO procure to help balance the national transmission network. Dynamic Containment is currently the most profitable (and most relevant to batteries) ancillary service, but as competition increases in the future (which is anticipated in 2022) the prices are likely to decline to a lower, but more stable, level (a trend seen with other ancillary services).	~£100,000 – £120,000	↘
Capacity Markets	Battery assets are currently de-rated by ~50%, so the value that they can secure is currently low.	~£500 – £3,000	→
DNO flexibility services	Some DNOs are procuring a range of flexibility services. There are currently no standards or long-term security in this revenue stream, and it is highly locational and ad-hoc dependant on specific DNOs and their needs.	~£1,000 – £5,000	→

[18] Estimates are based on a 1MW / 1 MWh battery asset

Table 25: Overview of available revenue streams with estimated value and future direction.

2.1. Energy Markets – Arbitrage

Profiting from energy price arbitrage means storing energy when the price is low and exporting when high. Arbitrage typically involves storing energy in the early hours of the morning and discharging in the evening. Electricity is traded in the Day Ahead (DA) and Intra-Day (ID) energy markets.

- **DA**: It is relatively straight forward to stay in control of the day ahead market with a storage device. However, opportunities to import electricity at very low prices and export at very high rates are rare in the day ahead market auctions. These auctions are therefore most useful for preparing reserve power to capitalise on generating revenue through other means.
- **ID**: The intra-day market has a far greater variability on power prices which can be utilised to optimise the revenue from a storage asset. There are generally hundreds of MW of power traded within each trading period, and there are promising opportunities here for solar generators which incorporate battery storage.

If participating in the Balancing Mechanism, plans must be submitted to National Grid an hour ahead of real time. The advantage here is access to the Balancing Mechanism, however it does not allow for intra-day market trading until the last moment before trading. Depending on circumstances, one option may be preferable to the other.

Any size of storage is eligible to take advantage of this service. It has limited value for standalone projects and the value varies by geography. For example, benefits are higher in south England compared to Scotland. This requires a high level of user input and management to take advantage of diurnal pricing. A community group may therefore find difficulty to access suitable resources for this and may wish to enlist the services of an aggregator on their behalf, which will cost (an aggregator management fee is in the region of 5-20% depending on the project).

The cost-benefit of utilising arbitrage must be considered in terms of battery degradation and lifetime. Chemical batteries will also have a warranted number of charge and discharge cycles which will be a limiting constraint on revenue generation through arbitrage. This is typically around 400 cycles per year for a lithium-ion battery for example. It is therefore important to discharge at the right time to receive the greatest potential reward. If well managed, arbitrage could result in revenues of up to £150/kWh across a year although this is highly variable and uncertain. Figure 25 below shows the cumulative revenue modelled across a given year for different discharge rates.

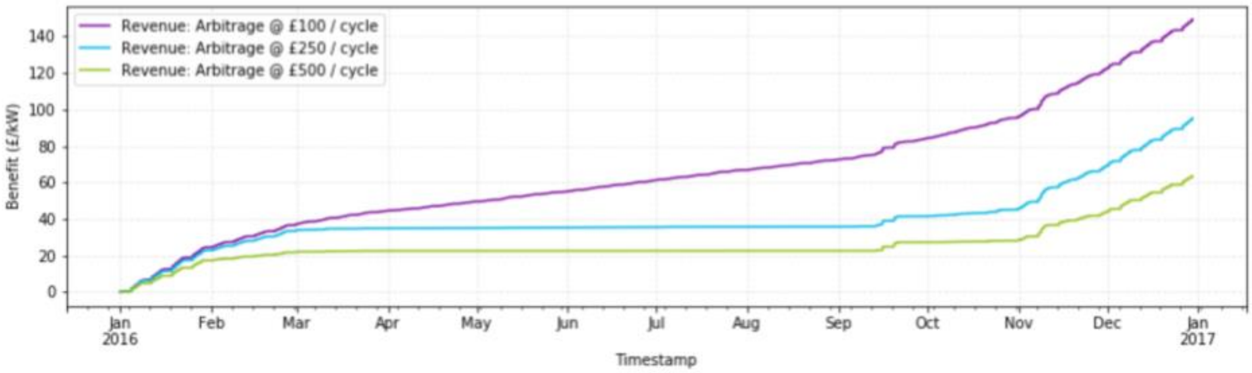

Figure 25: Modelled arbitrage revenue scenarios[19]

When co-located with solar there may be value in deferring export to the grid, especially in areas where there is high solar curtailment (often due to grid complexity/high numbers of local solar developments). Essentially, revenue is recognised by storing the solar generated and selling when the value of exported electricity is higher, rather than exporting directly to the grid.

This is an added revenue stream, but also added complexity: should the Client wish to do both, there could be 3-4 cycles per day which would ultimately degrade the battery faster. Therefore, a trade-off needs to be made between exporting the solar directly and using the batter for buy/sell only; versus using the battery to take advantage of both revenue streams at risk of reducing the asset's lifetime. Often it is the case that only curtailed energy is stored for future trading, as this is of least value.

2.2. Balancing Mechanism

The Balancing Mechanism is a tool used by National Grid to balance electricity supply and demand in close to real time. It is used to balance supply and demand in each half hour trading period of every day. Where an imbalance between electricity generation and demand is predicted by National Grid within a time period then it can accept bids to increase or decrease generation or consumption.

A key feature of the Balancing Mechanism is that every transaction and action is made public. National Grid are actively seeking to improve the accessibility of distributed generators in taking part in the Balancing Mechanism, particularly those with battery storage.

Minimum bid and offer sizes for the Balancing Mechanism are declared in tranches of 1MW. If the asset is less than 1MW then some aggregators are able to combine the asset with other projects sharing the same grid supply point (GSP), therefore overcoming the 1MW threshold and allowing participation. Certain qualifying criteria must also be met including to allow participation. For instance the bidder must qualify to be a Virtual Lead Party. This means that the services of an established aggregator are most likely required and advised to operate on behalf of the asset owners.

2.3. Ancillary Services

The Transmission System Operator (TSO), National Grid, has a portfolio of 'Ancillary Services' (or grid balancing services) that they procure to help them balance the electricity network that

[19] Robyn Lucas, Open Energi, Throughput vs. Revenues: Making the most from battery storage, 2019.

seek to maintain the frequency within the 49.5Hz-50.5Hz bracket. National Grid have two different markets currently available for frequency response, in which distribution-connected battery storage can participate, these are discussed subsequently:

- **Firm Frequency Response (FFR) market** procures a month in advance.
- **Dynamic Containment** faster-acting frequency response (soon to be accompanied by Dynamic Regulation (DR) and Dynamic Moderation (DM)).

There are others ancillary services, e.g. Reserve services such as STOR (Short-term operating reserve), which are less relevant for battery assets and hence will not be discussed further.

2.3.1. Firm Frequency Response

A generator offering a FFR service will be required to increase or decrease generation within 2 – 30 seconds, depending on the service type. The FFR service is split into two separate types, non-dynamic (static) and dynamic respectively. Non-dynamic FFR is a static frequency response and is triggered at a predefined contractual frequency deviation. No response is required within the National Grid operating range. Dynamic FFR is provided continuously and is used to manage second by second frequency variations. Dynamic FFR is an automatic response which will apply to all frequencies outwith 50Hz ± 0.015Hz. The Dynamic FFR is further split into Primary, Secondary and High products which defines the length and speed of the response of the service.

The minimum size of generator to contract directly with National Grid for FFR is 1MW. The type of generation for FFR must be dispatchable, meaning that output can be regulated at the operator’s discretion. This is ideally suited to fossil-fuel based generators such as gas plants and is not possible for intermittent and stochastic renewable generators to participate. The exception is if the renewable generator has onsite storage as part of the system which is of a size to make the system dispatchable such as batteries teamed with solar.

FFR is the largest frequency contract operating in the UK and has been generally beneficial to operators. The average price for non-dynamic FFR in 2019 was £2.87/MWh whilst the average dynamic FFR price across the same period was £6.39/MWh. Prices can however be much higher than this with the 2019-20 winter 24/7 average price being approximately £150/MWh. The annual peak in consumption is observed during winter evenings and this saw prices being as high as £600/MWh in some instances. It is cautioned that FFR payments are seasonally dependent and the high prices during winter evening peaks is highly influenced by coinciding with triad auction periods. Nonetheless, FFR represents one of the most reliable and financially rewarding options for assets to generate grid balancing service revenue.

There are a number of barriers that impact the accessibility of FFR for intermittent renewable energy assets. For example, Primary, Secondary and High products are procured as a single bundled product. In order to provide such a product, generators would have to operate part-loaded, meaning that output is below maximum. This is so that generation can be turned up or down as required. Revenue from exported generation is therefore reduced if operating at part-load compared to full load. Fossil fuel generators such as gas can more easily operate at part-load as a fuel reserve can be kept for use at another time. Intermittent renewable generators such as hydro, wind and solar do not have this luxury unless suitable storage is installed. Operating at partial load therefore equates to lost revenue which is uncertain to be recouped at a later date. Consequently, the cost for an intermittent renewable generator to provide frequency response as a bundle tends to be higher than competing fossil fuel generators as they must account for a lost opportunity cost.

2.3.2. Dynamic Containment

Dynamic Containment (DC) was launched in October 2021. This is possibly the most relevant to a battery asset. This is a fast-acting post-fault service (i.e. if a sudden demand or generation loss) to contain frequency within the statutory range of +/- 0.5Hz (of 50 Hz). It requires automatic dispatch to enable a battery to respond within 0.5 – 1 second to frequency deviations in the grid. The service runs tenders daily for 24 hours at a time, essentially looking to move the market closer to real time.

2.4. Capacity Market

Established by the UK Government and administered by the TSO, the Capacity Market is a series of auctions designed to boost capacity in the market to provide insurance against the possibility of blackouts as power stations come offline and more intermittent sources of power increase.

The Capacity Market was introduced by BEIS as part of the Electricity Market reform. A steady and predictable revenue stream is provided to assets which can deliver energy at times of system stress. Penalties are incurred by those which do not fulfil their Capacity Market contract obligations. New build generators should have an installed capacity of at least 2MW to contract directly with National Grid.

There are two capacity auctions each year:

- T-4: this is the main auction and buys the majority of capacity required for four years' time. New build generators can secure 15 year contracts.
- T-1: these are top-up auctions which take place ahead of each delivery year in case there are sites that were not ready for T-4. However, T-4 has higher prices so it is advantageous to bid within T-4. Existing generators can apply for one year contracts through this auction.

Payments are monthly and fixed by the agreed auction clearing price and therefore provides a valuable ensured revenue for developers and investors in a new generating project. Participants can bid for contracts in auctions four years ahead of commissioning. Projects that take payments from the Capacity Market are not eligible for Fast Reserve or STOR payments. Prices in the capacity market have collapsed considerably in recent years to less than £1/kW/a. The Capacity Market is not favourable for intermittent renewable energy generators as it relies on a firm and predictable supply which cannot be offered without taking very high risk.

2.5. DNO Flexibility Services

DNOs and DSOs

Presently, the UK has a single system operator, the National Grid, which is responsible for nation-wide frequency management and transmission. As the energy landscape changes from a fossil-fuel based, centralised system with a low number of connections to a more complex system with energy flow in both directions, greater storage, intermittent renewable generation and electricity for heat and transport, there is a necessity to more effectively manage the distribution system. There has therefore been a push for a transition from a district network operator (DNO) model to a distribution system operator (DSO) one.

DNOs have embraced this transition to DSO which is expected to occur around 2024. The transition is purposed to make it easier for distributed renewable generation schemes to be installed onto the local network. Under the current model, customers pay the DNO to connect and supply. A key feature of the new DSO model would see a more active network with customer participation and opportunity for the DSO to be paying the customer. This is a promising move for community and local energy, with smart microgrids offering services to boost resilience and reliability of the system and ensuring consumers are supplied with an affordable, available and low carbon energy supply whilst accelerating progress towards national climate change targets. Opportunities for community energy could also include enabling local energy markets for peer-to-peer trading and opening up revenue streams for customers through local grid balancing services. The creation of DSOs would be particularly beneficial in areas with grid constraints as smart local energy systems incorporating storage and trading would reduce the maximum export requirement to the grid. However, it should be noted that, compared to national grid services, DSO services are not anticipated to be as profitable, estimated to have an annual income of

£1-5k per MW per year, and are suited to smaller projects c. 1MW with a local grid connection and requirement for services.

The DSO service will vary geographically, however having a more local, focussed operator is bound to improve and encourage more proactive dialogue with local community groups and enterprises. The grid balancing services discussed in the proceeding sections reflect the current situation based on National Grid being the sole system operator across the UK.

Distribution Network Operators (DNOs) are at a very early stage of procuring flexibility from e.g. battery assets as well as other types of loads, to provide support to the local distribution electricity grid. Several DNOs use a marketplace called Piclo to present bids and offers for grid support that they require. There are currently no standards or long-term security in this revenue stream, and it is highly locational and ad-hoc, dependant on DNO needs.

3. Community groups' routes to market

The next step for MCLT would be to discuss the project with a specialist battery optimisation provider (discussed subsequently) and gauge their interest on the prospective asset, what scale would be useful and what the potential revenues may be if installed in this location. As this is a National Grid service, generally location is not an issue, however the connection for the Marshfield site would be a considerable distance, which may impact the time taken to supply the service and therefor may be technically challenging.

Alternatively, the Community group could approach storage installers to offer the available land and solar generation to a storage project. By collaborating with the community group the developer will have improved case in planning, presumably a low rent and also a reduced grid connection cost. The community group may not make any revenue from the storage project, but would avoid the risk in entering the storage market, and would benefit from a reduced cost of the grid connection and may be able to secure a valuable PPA for the solar energy.

3.1.1. Battery Optimisation Providers

There are many existing organisations who would be capable of supporting the community group in operating within these markets. To ensure the storage system is managed to maximise revenue streams it is recommended that MCLT engage with a battery optimisation partner to provide 24/7 optimisation of the battery to enable the asset to be optimised to its full potential and create positive returns on your investment. The technology and value streams are complex and to ensure return on your investment it is vital to work with a company that has this type of experience and capabilities. Optimisation management fees are in the region of 10-20%, due to the continuous effort required to optimise the asset.

There are a variety of providers that can provide this optimisation, including:

- Aggregators, e.g. Flexitricity, Grid Beyond, Upside Energy, Lime Jump.
- Battery optimisers, e.g. Habitat Energy, Arenko.
- Energy suppliers, e.g. Centrica, EDF Energy, ESB.
- Energy Traders, e.g. VEST energy.

Aggregators don't guarantee any prices for energy, but instead take a management fee. Generally, this fee will be 2-10% of the profits made. They are therefore incentivised to make as much money from the trading of balancing serviced as possible. Most of these providers also offer a wider selection of services, including turnkey solutions.

4. Project Risks and Uncertainties

The main uncertainty is the level of revenue generation in the future, given the lack of long-term contracts and dynamic nature of the market. There is limited certainty in the exact value that could be generated from these revenue streams, given the lack of long-term contracts, the dynamic nature of the energy market and competition driving prices up/down.

The value in the markets are dynamic and vary depending on a multitude of factors including the need for service provision (e.g. TSO need for frequency response), competition (e.g. the more providers offering frequency services, the more the price is depressed), and regulation (e.g. OFGEM changing the market rules will lead to great volatility in the value within the Balancing Mechanism).

However, there are a number of fundamental factors that can provide confidence in investment:

- National Grid has, and likely always will, require support to balance the grid. For years power stations have provided ancillary services, but as these come offline and are not being replaced, the TSO therefore requires new forms of support. A number of different types of response will be needed, including batteries that can provide frequency support.
- There is increasing price volatility in the energy markets and balancing mechanism and this is expected to continue as more renewables are introduced, the settlement period reduces and as time-of-use tariffs increase. These changes will bring about a more liquid market and present more opportunities to monetise flexibility.

Discussing price evolution with aggregators we found general agreement in terms of price evolution, as follows:

- It is expected that Dynamic Containment will provide a 6 figure per MW revenue in 2021 and 2022, when more competition is anticipated to enter the market. Once competition increases the value will be eroded but will likely remain a key revenue stream for battery systems.
- As the energy markets develop, it is anticipated that larger revenue opportunities will occur in the energy markets (day ahead, intraday day and balancing mechanism), although from a low base. Overall, market stakeholders remain positive that the dynamic nature of the market will drive an acceptable return for investors.
- One stakeholder believes there is more value in hedging flexibility in the future energy markets, as more energy suppliers without generation assets require future flexibility to balance their position in the market (an issue felt last winter by many smaller suppliers).

5. Next steps

Should the Client proceed with a battery option at the site, Locogen would recommend the following next steps:

1. Gather indicative revenue and optimisation offers from a variety of aggregators/battery optimisation companies;
2. Approach aggregators and/or third party developers to assess their interest in stepping into the project and for initial offers to be made to quantify the rental business model;
3. Commission a specification for the battery technology and gather quotes from a selection of manufacturers;
4. Share a summary of this information alongside recommendations of which providers to select;
5. Pending this outcome – confirm grid connection and proceed with the project.

Appendix F. Additional reading and case studies

The below case studies were provided by Sharenergy to provide some examples to MCLT of subsidy free and challenging community projects of a similar nature. As a general note, Sharenergy reiterate that there are very few post-FIT case studies available, and very little community energy has been installed in the last two years without FIT.

- Egni[20] were using up their previous FiT accreditation which was extended due to Covid. Also all their installations are on buildings that use at least some of the electricity generated.
- Reading hydro[21] and Congleton Hydro[22], both have FiT and direct wire arrangements, Reading to a Lido, Congleton to the Siemmens factory.
- Bristol Hydro[23] has not got the FiT but they have received 50% ERDF funding instead.
- The 4.2 MW wind turbine at Avonmouth for Lawrence Weston Ambition[24] is the most significant post FiT scheme to our knowledge. However, it has the advantage of scale and has also received £500k of grant funding from the West of England Combined Authority.
- There is also the 30MW ground mounted solar scheme at Bretton Hall[25]. This project is grid connected and has no capital funding but again has the advantage of scale.
- Creacombe Solar Farm Extension[26] is subsidy free, again this is large and is being developed as part of a larger scheme which has FiTs accreditation.
- Sharenergy are working on a 2MW solar farm in Oswaldtwistle with the Prospects Foundation, but this will only be viable if we can arrange a direct wire connection into a neighbouring industrial facility.
- The Low Carbon Hub are pushing forward with the Ray Valley Solar Farm[27]. This project is 19MW so again has the advantage of scale.
- Sharenergy have also been working on setting up the Big Solar Co-op[28] which aims to address the issue of risk with pots FiT rooftop solar.

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20 https://egni.coop

21 https://readinghydro.org

22 https://www.congletonhydro.co.uk

23 https://bristolenergy.coop/a-busy-year-for-the-bristol-community-hydro-scheme

24 https://thebristolmayor.com/2020/10/23/renewable-energy

25 https://brettonhallsolar.squarespace.com/eng-02-exhibboards

26 https://www.creacombesolarfarm.co.uk

27 https://www.lowcarbonhub.org/p/projects/ray-valley-solar

28 www.bigsolar.coop