General Disclaimer
This document is provided "as is" for your information only and no representation or warranty, express or implied, is given by Aurora Energy Research Limited and its subsidiaries Aurora Energy Research GmbH and Aurora Energy Research Pty Ltd (together, "Aurora"), their directors, employees agents or affiliates (together, Aurora's "Associates") as to its accuracy, reliability or completeness. Aurora and its Associates assume no responsibility, and accept no liability for, any loss arising out of your use of this document. This document is not to be relied upon for any purpose or used in substitution for your own independent investigations and sound judgment. The information contained in this document reflects our beliefs, assumptions, intentions and expectations as of the date of this document and is subject to change. Aurora assumes no obligation, and does not intend, to update this information.

Forward-looking statements
This document contains forward-looking statements and information, which reflect Aurora's current view with respect to future events and financial performance. When used in this document, the words "believes", "expects", "plans", "may", "will", "would", "could", "should", "anticipates", "estimates", "project", "intend" or "outlook" or other variations of these words or other similar expressions are intended to identify forward-looking statements and information. Actual results may differ materially from the expectations expressed or implied in the forward-looking statements as a result of known and unknown risks and uncertainties. Known risks and uncertainties include but are not limited to: risks associated with political events in Europe and elsewhere, contractual risks, creditworthiness of customers, performance of suppliers and management of plant and personnel; risk associated with financial factors such as volatility in exchange rates, increases in interest rates, restrictions on access to capital, and swings in global financial markets; risks associated with domestic and foreign government regulation, including export controls and economic sanctions; and other risks, including litigation. The foregoing list of important factors is not exhaustive.

Copyright
This document and its content (including, but not limited to, the text, images, graphics and illustrations) is the copyright material of Aurora, unless otherwise stated.
This document is confidential and it may not be copied, reproduced, distributed or in any way used for commercial purposes without the prior written consent of Aurora.
Agenda

I. Background and recent activity

II. Revenue stacking for UKPN flexibility contracts

III. Key challenges for LFMs
Local Flexibility Markets have been established in response to growing operational complexities arising from the energy transition

I. Background and recent activity

With the UK's energy mix becoming increasingly intermittent and decentralised over the last decade, the need for location-specific flexibility services connected to the distribution network has been growing.

Local Flexibility Markets (LFMs) first emerged in 2017 from UKPN and WPD as a means to establish a Distribution System Operator (DSO) function which would directly procure flexible, dispatchable capacity to better manage the distribution network.

LFMs specifically help reduce reinforcement and operational risks for DNOs that have increased with the deployment of intermittent generation and uptake of electrified demand.

<table>
<thead>
<tr>
<th>Market Overview</th>
</tr>
</thead>
<tbody>
<tr>
<td>▪ Network issues are primarily addressed through traditional network solutions, i.e. wires and substations.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Service Overview</th>
</tr>
</thead>
<tbody>
<tr>
<td>▪ In 2020, four standardised services for LFMs were launched across all DNOs in GB, coordinated through the ENA's Open Networks Project.</td>
</tr>
</tbody>
</table>

The introduction of standardised contracts aims to reduce complexity and create a level playing field to increase market confidence and encourage participation.

Although contracts are standardised, specific requirements vary by location and range from rolling framework agreements, to 7-year fixed contracts depending on site characteristics. Successful applicants receive both availability and/or utilisation payments.

<table>
<thead>
<tr>
<th>DNO</th>
</tr>
</thead>
<tbody>
<tr>
<td>▪ Network issues are primarily addressed through traditional network solutions, i.e. wires and substations.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>DSO</th>
</tr>
</thead>
<tbody>
<tr>
<td>▪ Competitive markets are used as an alternative to network reinforcement. LFMs are established to procure capacity from various technologies.</td>
</tr>
</tbody>
</table>

Relative to traditional methods, DSO alternative measures can provide:

- Greater network efficiency and lower consumer costs
- Market driven price signals for the value of embedded flexibility
- Revenue stacking opportunities for participants
- Synergies with other system operators

<table>
<thead>
<tr>
<th>Product overview</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 Sustain</td>
</tr>
<tr>
<td>2 Secure</td>
</tr>
<tr>
<td>3 Dynamic</td>
</tr>
<tr>
<td>4 Restore</td>
</tr>
</tbody>
</table>

1) Energy Network Association 2) The service also serves pre-fault constraints for UKPN
I. Background and recent activity

Over 1 GW of capacity has been procured through DNO flexibility tenders in 2020, with total requirements scaling up to 3 GW in 2021

Total tendered and contracted volumes in DNO flexibility tenders in 2020 and 2021

MW (/MVAr for reactive power)

<table>
<thead>
<tr>
<th>Sustain</th>
<th>Secure</th>
<th>Dynamic</th>
<th>Restore</th>
<th>Reactive Power</th>
</tr>
</thead>
<tbody>
<tr>
<td>28</td>
<td>481</td>
<td>827</td>
<td>771</td>
<td>1,088</td>
</tr>
<tr>
<td>+46%</td>
<td>41%</td>
<td>72%</td>
<td>23%</td>
<td>+29%</td>
</tr>
<tr>
<td>28</td>
<td>41</td>
<td>827</td>
<td>771</td>
<td>1,088</td>
</tr>
</tbody>
</table>

Comments

- Since 2017, DNOs have been tendering for and procuring various flexibility services at the local distribution network level to solve congestion in the local electricity grids
- The total size of local flexibility markets in 2020 across GB DNOs for all four standard flexibility products has seen a significant increase, with the total contracted volumes amounting to over 1 GW
- DNOs have been scaling up their volume requirements further in 2021, looking to procure ~3 GW across four standardised products, though around 1.3 GW of the total volumes has already been contracted

UKPN total flexibility volume by tender round, 2017 - 2021

MW

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Total tendered capacity</td>
<td>37.6</td>
<td>136</td>
<td>153</td>
<td>387</td>
</tr>
<tr>
<td>Total awarded capacity</td>
<td>0.3</td>
<td>19.3</td>
<td>123</td>
<td>350</td>
</tr>
</tbody>
</table>

1) Data published by ENA in February 2021. Different products requirements are counted separately. Includes sustain, secure, dynamic and restore; peak capacity is used (maximum possible capacity required at any point in time)

Sources: Aurora Energy Research, Energy Network Association, UK Power Networks
**DNO flexibility services are stackable similar to traditional forms of dispatch, being chiefly compatible with a CM contract**

Revenues stacking for standardised local flexibility products by DNOs:

<table>
<thead>
<tr>
<th>Same Time Period</th>
<th>Wholesale</th>
<th>Capacity Market</th>
<th>Balancing Mechanism</th>
<th>Replacement Reserve</th>
<th>Ancillary Services</th>
<th>DNO Sustain</th>
<th>DNO Secure</th>
<th>DNO Dynamic</th>
</tr>
</thead>
<tbody>
<tr>
<td>DNO Restore</td>
<td>No</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>DNO Dynamic</td>
<td>No</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>DNO Secure</td>
<td>No</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>DNO Sustain</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td></td>
</tr>
</tbody>
</table>

Key considerations:

1. **Wholesale and DNO Secure**: Revenue stackability with wholesale trading varies by DNOs. Some dispatch for the Secure product is instructed in advance (e.g., week-ahead for WPD) so the relevant FP\(^1\) can trade to that position. However, for DNOs where dispatch is closer to real time, revenues are not stackable.

2. **Capacity Market**: There is no obligation to export power other than during a system stress event, which carries a penalty for non-delivery\(^2\). CM rules exempt providers in 'Relevant Balancing Services' (most NGSESO ancillary services) from exporting during stress events. A CM rule change could be raised to extend this to LFMs.

3. **DNO products**:
   - Assets cannot be dispatched for both Restore and Dynamic or Secure services in the same time period. However, as services (e.g. Sustain, Secure and Dynamic) can be across different voltage levels (HV and LV), stacking across services is available if both LV and HV needs are accessible by FPs\(^1\).
   - The performance related payment deductions for non-delivery of DNO services is capped at the maximum payment.

4. **DNO Sustain**: As scheduled availability is pre-agreed within the contract, FP\(^1\) can trade in the WM/BM outside of the contracted window.

5. In general, most services are readily stackable with DNO products in adjacent time periods, and less so in the same time period.

---

1) Flexibility providers, 2) Penalties for non-delivery during stress events are capped at twice the monthly revenue per event, total penalties may not exceed the annual contract revenue.

Sources: Aurora Energy Research, Energy Network Association, UK Power Networks
Three flexibility services are being offered by UKPN, with contract lengths ranging from 1 to up to 7 years

**UKPN Flexibility Service Overview:**

<table>
<thead>
<tr>
<th>Secure</th>
<th>Sustain</th>
<th>Dynamic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Increase generation or decrease demand to reduce peak loads on High Voltage (HV) substations</td>
<td>Increase generation or decrease demand to reduce peak loads on Low Voltage (LV) substations</td>
<td>Increase generation or decrease demand to meet a variety of network needs¹</td>
</tr>
</tbody>
</table>

- FPs³ paid for availability (£/MW/h) and/or utilisation (£/MWh) as bid
- FPs³ paid a fixed £/MW service fee
- FPs³ paid for utilisation (£/MWh) at a price set by the FP; No Service Windows

Minimum ( aggregated) 10kW threshold

- FPs³ commit delivery >6 months ahead (at contract)
- FPs³ commit delivery 1 month ahead of delivery (option for 1 week)
- Optional on FP³ to accept dispatch instruction

<table>
<thead>
<tr>
<th>Real-time dispatch</th>
<th>Scheduled dispatch</th>
<th>Real-time dispatch</th>
</tr>
</thead>
</table>

**UKPN payment structure for Flexibility Services - Secure product:**

- Utilisation Payment (£) = Utilisation Fee (£/MWh) * Energy Delivered (MWh)
- Availability Payment (£) = Availability fee (£/MW/h) * Contracted Capacity (MW) * Total Periods Available (h) * Performance Factor (%)

Performance Factor:

- >= 90%
- <90% and >= 80%
- <80% and >= 70%
- <70% and >= 60%
- <60%

¹ E.g. supplement Secure, manage outages ² Delivery performance is calculated as the monthly ratio of all delivered energy (capped by its contracted energy) to all contracted energy expected during utilisation events. ³ Flexibility Provider
I. Background and recent activity

UKPN's February 2021 Flex Tender awarded 350 MW of capacity at a total cost of £30m across 137 voltage zones

Contract lengths ranged between one and seven years which covered 77 high voltage and 60 low voltage zones have been awarded to 17 companies.

In November 2020, UKPN released flexibility requirements of 387 MW covering 138 sites with more than £50m available for the services. Three categories were to be covered: Secure, Sustain and Dynamic. Delivery of the services will start in Winter 2021/22, Summer 2021, Winter 22/23 or Summer 2022.

- Secure
  - Reduces HV substation peak load
  - Paid for availability (£/MW/h) and utilisation (£/MWh)
  - > 6-month ahead commitment
  - Total: 81.6 MW
  - Total contract value £m: 2.2

- Sustain
  - Reduces LV substation peak load
  - Single fixed service fee (£/MW)
  - Month- or week-ahead commitment
  - Total: 20.4 MW
  - Total contract value £m: 5.1

- Dynamic
  - Reduces HV and LV substation peak load
  - Utilisation payments (£/MWh)
  - Real time dispatch which is optional for the provider to accept
  - Total: 248.1 MW
  - Total contract value £m: 23.0

Sources: Aurora Energy Research, UK Power Networks
Agenda

I. Background and recent activity

II. Revenue stacking for UKPN flexibility contracts

III. Key challenges for LFMs
We use UKPN’s Secure service to examine the additional value that a LFM contract can provide to batteries and gas recip

II. Revenue stacking for UKPN flexibility contracts

Average availability and utilisation payments from February 2021 tender

<table>
<thead>
<tr>
<th>Availability Payment</th>
<th>Utilisation Payment</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>£29/MW/h</td>
<td>£174.5/MWh</td>
<td></td>
</tr>
</tbody>
</table>

Total MW requirements across UKPN DNO regions for Secure Product from February 2021 tender

<table>
<thead>
<tr>
<th>Region</th>
<th>21/22</th>
<th>22/23</th>
<th>23/24</th>
<th>24/25</th>
<th>25/26</th>
<th>26/27</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>EPN</td>
<td>60</td>
<td>23</td>
<td>26</td>
<td>26</td>
<td>26</td>
<td>30</td>
<td>182</td>
</tr>
<tr>
<td>SPN</td>
<td>20</td>
<td>16</td>
<td>17</td>
<td>14</td>
<td>11</td>
<td>13</td>
<td>84</td>
</tr>
<tr>
<td>LPN</td>
<td>15</td>
<td>8</td>
<td>2</td>
<td>9</td>
<td>9</td>
<td>3</td>
<td>43</td>
</tr>
</tbody>
</table>

1) Includes total MW requirements in summer and winter 2) Volume-weighted average published by UKPN

Sources: Aurora Energy Research, UK Power Networks

CONFIDENTIAL
II. Revenue stacking for UKPN flexibility contracts

A Winter LFM contract can boost battery gross margins relative to energy trading only, however the gain is higher for smaller assets

Average gross margins from 2021-2027 for a new build 1h battery cycling 1.5x per day with different asset configurations

- **HV-connected, 1 MW battery**
  - Energy Trading Only: £65/kW/year
  - Energy Trading + UKPN Secure Service: £99/kW/year
  - +54%

- **HV-connected, 10 MW battery**
  - Energy Trading Only: £65/kW/year
  - Energy Trading + UKPN Secure Service: £75/kW/year
  - +16%

Key assumptions:

- **Energy trading:** battery can trade in the Wholesale and Balancing markets outside of the contracted Secure service availability window (assumes the asset opts out from energy trading between 4-8pm)

- **LFM:** assumes a 7-year winter contract (Nov – Feb) for UKPN Secure service with a contracted size of 1 & 4 MW for two battery size

- **Capacity Market:** assets are eligible to stack a CM contract on top of LFM

- **Embedded benefits:**
  - GDUoS/EET: Eastern England rates
  - Assets are eligible to receive embedded benefits if they export during LFM windows, as network charging arrangements do not distinguish between self-dispatch and instruction by UKPN

Sources: Aurora Energy Research, UK Power Networks

---

A 7-year Secure winter contract from UKPN provides a 54% margin uplift for a 1 MW HV-connected battery asset, increasing gross margins by £34/kW/year

However, due to potentially lower LFM requirements, a 10 MW battery may only be able to obtain a 4 MW LFM contract. In this example, a 10 MW asset would see a smaller gross margin uplift of 16%, £10/kW/year

---

1) Batteries participating in the service are allowed to export during the availability window (but not import), though a reduced availability payment could apply as a result of a lower performance factor, if assets fail to subsequently meet DNO’s dispatch instruction after discharging in the previous period(s).
Securing a 1 MW 7-year Winter LFM contract from UKPN increases project IRR by 8% for a new build 1 MW HV-connected battery

Net Present Value (NPV)\(^1\) for a new build HV-connected 1 MW/1 MWh battery cycling 1.5x per day, 2021 entry

\[\text{\pounds k real 2020}\]

11% discount rate used for all merchant revenue streams, and 6% for contracted revenues (CM and LFM) and fixed costs

<table>
<thead>
<tr>
<th>Item</th>
<th>£k real 2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total CAPEX and fixed costs</td>
<td>-502</td>
</tr>
<tr>
<td>Energy Trading margins</td>
<td>-19</td>
</tr>
<tr>
<td>Embedded benefits(^3)</td>
<td>-19</td>
</tr>
<tr>
<td>15-year CM contract(^2)</td>
<td>186</td>
</tr>
<tr>
<td>End-of-life value(^4)</td>
<td>-19</td>
</tr>
<tr>
<td>Total margins without LFM</td>
<td>186</td>
</tr>
<tr>
<td>Reduction in ET margins</td>
<td>186</td>
</tr>
<tr>
<td>Increase in EB</td>
<td>186</td>
</tr>
<tr>
<td>UKPN Secure Service</td>
<td>186</td>
</tr>
<tr>
<td>Total</td>
<td>186</td>
</tr>
</tbody>
</table>

Pre-tax IRR unlevered %

10.9%

Pre-tax IRR unlevered %

19.0%

1) NPV calculated based on discount factors of 6% for CM (15-year) and LFM (7-year) revenues and fixed costs, and 11% for all other revenues and costs over 15-year lifetime. 2) We assume asset taking 15-year CM contracts at the price of the entry year. 3) Includes Triads EET, BSuoS and GDUoS. Done for an average asset for Aurora Central although in practice, this could differ considerably by individual expectations. 4) Assumes £150/kW for 1 hour battery.

1) Grid connection costs could be lower/higher than the average assumption. HV sites in UKPN regions can be scarce.

2) Asset with 2021 entry requires ~£19/kW to break even mainly as a result of lower CM clearing price and reduced de-rating factor.

3) Reduction in trading margins accounts for the additional charging costs (~£3/kW/year) to meet the State of Charge requirement during service window.

4) As the asset is eligible for GDUsO payments during service utilisation, embedded benefits see an increase, with average cycling rate increasing by ~0.2 times/day.
Though smaller, securing a 4 MW LFM contract for a new build 10 MW HV connected battery still increases project IRR by ~3%.

Net Present Value (NPV)\(^1\) for a new build HV-connected 10 MW/10 MWh battery cycling 1.5x per day, 2021 entry

<table>
<thead>
<tr>
<th>£k real 2020</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>-5,018</td>
<td></td>
</tr>
<tr>
<td>Energy Trading margins</td>
<td></td>
</tr>
<tr>
<td>Embedded benefits(^3)</td>
<td></td>
</tr>
<tr>
<td>15-year CM contract(^2)</td>
<td></td>
</tr>
<tr>
<td>End-of-life value(^4)</td>
<td></td>
</tr>
<tr>
<td>Total margins without LFM</td>
<td>-185</td>
</tr>
<tr>
<td>Reduction in ET margins</td>
<td></td>
</tr>
<tr>
<td>Increase in EB</td>
<td></td>
</tr>
<tr>
<td>UKPN Secure Service</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>614</td>
</tr>
</tbody>
</table>

11% discount rate used for all merchant revenue streams, and 6% for contracted revenues (CM and LFM) and fixed costs

Pre-tax IRR unlevered %

| ▪ Grid connection costs could be lower/higher than the average assumption. HV sites in UKPN regions can be scarce |
| ▪ Asset with 2021 entry requires ~£19/kW to break even mainly as a result of lower CM clearing price and reduced de-rating factor |
| ▪ Reduction in trading margins accounts for the additional charging costs (~£3/kW/year) to meet the State of Charge requirement during service window |
| ▪ As the asset is eligible for GDUoS payments during service utilisation, embedded benefits see an increase of £123k (£12.3/kW), with average cycling rate increasing by ~0.2 times/day |

1) NPV calculated based on discount factors of 6% for CM (15-year) and LFM (7-year) revenues and fixed costs, and 11% for all other revenues and costs over 15-year lifetime. 2) We assume asset taking 15-year CM contracts at the price of the entry year. 3) Includes Triads EET, BSUoS and GDUoS. Done for an average asset for Aurora Central although in practice, this could differ considerably by individual expectations. 4) Assumes £150/kW for 1 hour battery.

Sources: Aurora Energy Research, UK Power Networks
II. Revenue stacking for UKPN flexibility contracts

For gas recips, securing a winter LFM contract increases yearly margins by 13% and 8% for 1 MW and 10 MW assets respectively

Average gross margins from 2021-2027 for a new build gas recip with different asset configurations

- HV-connected, 1 MW gas recip (35% HHV efficiency, ETS-exempted) £/kW/year real 2020
  - Energy Trading Only: 130
  - Energy Trading + UKPN Secure Service: 146
  - +13%

- HV-connected, 10 MW gas recip (38% HHV efficiency, no exemption) £/kW/year real 2020
  - Energy Trading Only: 105
  - Energy Trading + UKPN Secure Service: 113
  - +8%

Key assumptions:

- Energy trading: gas recips can trade in the Wholesale and Balancing markets outside of the contracted Secure service availability window (assumes the asset opts out from energy trading between 4-8pm)

- LFM: assumes a 7-year winter contract (Nov – Feb) for UKPN Secure service with a contracted size of 1 & 4 MW for two battery size

- Capacity Market: assets are eligible to stack a CM contract on top of LFM

- Embedded benefits:
  - GDUoS/EET: Eastern England rates
  - Assets are eligible to receive embedded benefits if they export during LFM windows, as network charging arrangements do not distinguish between self-dispatch and instruction by UKPN

Sources: Aurora Energy Research, UK Power Networks

Exemplary business case

A 1 MW asset is ETS exempt under current regulations due to its size, delivering higher energy trading gross margins than a 10 MW asset

A 7-year Secure winter contract from UKPN provides a 13% margin uplift for a 1 MW ETS-exempted gas recip, increasing gross margins by £16/kW/year

However, due to potentially lower LFM requirements, a 10 MW gas recip may only be able to obtain a 4 MW LFM contract. In this example, a 10 MW asset would see a smaller gross margin uplift of 8%, £8/kW/year
II. Revenue stacking for UKPN flexibility contracts

A 1 MW ETS exempt gas recip sees an increase in project IRR by ~2% by securing a LFM contract

Net Present Value (NPV)\(^1\) for a new build 35% HHV efficiency, HV-connected 1 MW gas recip with ETS exemption, 2021 entry

£k real 2020

11% discount rate used for all merchant revenue streams, and 6% for contracted revenues (CM and LFM) and fixed costs

Exempted ETS assets benefit from a material reduction in SRMC that increases overall run hours and captured spark-spreads. However, this could be subject to future reviews

1) NPV calculated based on discount factors of 6% for CM (15-year) and LFM (7-year) revenues and fixed costs, and 11% for all other revenues over the 25-year lifetime
2) We assume asset taking 15-year CM contracts at the price of the entry year
3) Post-CM rolling contracts
4) Includes Triads EET, BSUoS and GDUoS. Done for an average asset for Aurora Central although in practice, this could differ considerably by individual expectations.

Grid connection costs could be lower/higher than the average assumption. HV sites in UKPN regions can be scarce

Trading margins sees a reduction of £47/kW as the asset is fully contracted to provide LFM service in winter, thus losing Wholesale and Balancing revenues from evening peaks

Asset also sees a reduction in embedded benefits due to reduced export hours during evening peak where HV-connected assets in UKPN regions enjoy lucrative GDUoS red rates

However, a 7-year Winter Secure contract (November to February) with UKPN not only counteracts the reduction in trading and embedded benefits, but provides a net increase of £40k (£40/kW) in total NPV for the asset

Sources: Aurora Energy Research, UK Power Networks
Similarly, a 10 MW gas recip achieves an increase of 2% in project IRR with a 7-year Winter LFM contract

<table>
<thead>
<tr>
<th>Net Present Value (NPV)</th>
<th>for a new build 38% HHV efficiency, HV-connected 10 MW gas recip with no ETS exemption, 2021 entry</th>
</tr>
</thead>
<tbody>
<tr>
<td>£k real 2020</td>
<td>$6,976</td>
</tr>
</tbody>
</table>

**II. Revenue stacking for UKPN flexibility contracts**

**Exemplary business case**

A 10MW asset would typically benefit from higher efficiency vs a 1MW asset, however would not be ETS exempt. The loss of the ETS exemption outweighs the efficiency gain, resulting in lower energy trading margins.

As contracted size is smaller than total capacity (4 MW), the increase in total margins is proportional to asset size.

**Grid connection costs could be lower/higher than the average assumption. HV sites in UKPN regions can be scarce.**

**Trading margins sees only a slight reduction as the asset is only contracted to provide 4 MW of LFM service, with the remaining capacity able to trade in the WM and BM capacity.**

**Similarly for embedded benefits, only a minor reduction is seen as the asset is able to capture GDUoS payments during the service utilisation hours while using its non-contracted capacity to trade in Wholesale and Balancing markets.**

**As a result, a 7-year Winter Secure contract (November to February) with UKPN provides a net increase of £576k (£57.6/kW) in total NPV for the asset.**

1) NPV calculated based on discount factors of 6% for CM (15-year) and LFM (7-year) revenues and fixed costs, and 11% for all other revenues over the 25-year lifetime.
2) We assume asset taking 15-year CM contracts at the price of the entry year.
3) Post-contracts CM revenues assume 1-year rolling contract using H1 Central Forecast. Includes Triads EET, BSUoS and GDUoS. Done for an average asset for Aurora Central although in practice, this could differ considerably by individual expectations.

Sources: Aurora Energy Research, UK Power Networks
Agenda

I. Background and recent activity

II. Revenue stacking for UKPN flexibility contracts

III. Key challenges for LFMs
**III. Key challenges for LFMs**

**Whilst DNO LFMs could enhance flexible asset business cases, three main challenges remain**

<table>
<thead>
<tr>
<th>Key Challenges</th>
<th>Implications</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Size and location</strong></td>
<td></td>
</tr>
<tr>
<td>▪ Flexibility requirements for LFMs are highly locational and narrowly defined</td>
<td>▪ Difficult for assets to participate in these services unless they are already situated in the right locations, or new-builds can source appropriate sites</td>
</tr>
<tr>
<td>▪ Grid connection costs could vary depending on the location, while land availability for HV sites can be scarce</td>
<td>▪ Potentially useful for DNOs to share more information like UKPN on revenue ranges and availability on grid connection for each region</td>
</tr>
<tr>
<td>▪ Though varying depending on network asset characteristics, LFM requirements are typically small in volumes</td>
<td>▪ If LFM requirements are small, it is unlikely to materially enhance project economics greater than 10 MW. Economics would improve in areas with higher LFM requirements.</td>
</tr>
<tr>
<td>▪ For instance, the largest awarded contract size is 3.9 MW from UKPN’s April 2020 tender</td>
<td>▪ Developers face additional challenges for smaller assets, such as lower efficiency or higher capex (£/kW) with less economies of scale</td>
</tr>
</tbody>
</table>

| **Revenue stackability**                                                      |                                                                              |
| ▪ Uncertainty over how different revenue streams can be stacked with a LFM contract | ▪ Although certain revenue stacking has been allowed such as CM and embedded benefits, offering further flexibility for stacking with alignment between ESO and DSO dispatch could encourage more build of assets in the required regions – UKPN are working on this through the Regional Development Programme |
| ▪ Ongoing NAFLC reform casts further uncertainty over investment decisions for new-build distributed assets as regions (e.g. UKPN) with high embedded benefits could see large revision depending on the final decision from Ofgem | ▪ Potentially useful for DNOs to publish data on historical utilisation prices and volumes for each region on a more frequent basis |
| ▪ The opportunity costs of participating in DNO services are determined by value available from energy trading or other ancillary services. For batteries operating in Dynamic Containment (DC), this is currently set at £17/MW/h from 24h contract and the high price has made it difficult for other services to compete in the short term | ▪ Though high DC prices currently set the opportunity cost for batteries providing LFM services, DC procurement moving to EFA blocks will allow more flexibility for service stacking. As UKPN winter contract could offer an average of £29/MW/h availability rates during evening peaks, providing LFM during EFA blocks 5&6 would yield higher returns than current DC prices |

| **Visibility of future service requirement**                                  |                                                                              |
| ▪ Though high availability and/or utilisation payments are currently being offered in certain regions with high network requirements, uncertainty remains over how static current zonal requirements are and how long these benefits would remain in place | ▪ Difficult to make investment decision for new build projects based on LFM revenues as it remains unclear whether future regional will stay the same for each region |
| ▪ Potentially useful for DNOs to share a forward looking plan identifying the most critical areas with need for flexibility. UKPN currently publishes out 7 years | |
Key takeaways

1. With the UK’s energy network becoming increasingly decarbonised and decentralised, Local Flexibility Markets (LFMs) have been increasingly used by DNOs to procure flexibility services at the local distribution network, as part of the transition from DNOs to DSOs. Contracted volumes grew from ~250 MW to over 1 GW in 2020, with further increase in procurement target of up to 3 GW in 2021.

2. For batteries, a 7-year winter LFM contract from UKPN’s Secure Service can boost battery gross margins relative to energy trading only. The increase in project IRR is significant at ~8% for a 1 MW battery as the asset is able to fully capitalise on the LFM contract, whereas a 10 MW asset sees a relatively smaller increase in IRR at ~3% due to a limit in contract size.

3. For gas recips, securing a 7-year winter LFM contract from UKPN’s Secure Service increases yearly margins by 13% and 8% for 1 MW and 10 MW assets respectively. Both assets see an increase in project IRRs by ~2% with the revenue stacking with a LFM contract.

4. Whilst LFM contracts provide lucrative additional revenues to the flex business cases, three main challenges remain around the current limitation on contract size and highly locational nature of the LFM requirements, uncertainties over revenue stackability and locational benefits being reformed under NAFLC, and limited visibility on future service requirements. These issues would need to be addressed to provide better investment signal for the LFMs. UKPN already publish 7 years ahead and are looking to increase visibility. Also, work at the Open Networks project with other DNOs and ESOs aims to tackle the other challenges.

Source: Aurora Energy Research, UK Power Networks

1) Network Access and Forward Looking Charges