

TECHNO-ECONOMIC ASSESSMENT OF NATURAL GAS DISPLACEMENT POTENTIAL OF BIOMETHANE: A CASE STUDY ON DOMESTIC ENERGY SUPPLY IN THE UK

Tekena Fubara¹, Franjo Cecelja¹, Aidong Yang^{2, *}

¹Department of Chemical Process Engineering, University of Surrey, Guildford, GU2 7XH, UK

²Department of Engineering Science, University of Oxford, Oxford, OX1 3PJ, UK

*Corresponding author. Tel: +44 1865273094, e-mail: aidong.yang@eng.ox.ac.uk

ABSTRACT

Mathematical modelling and optimisation at both household and energy supply network levels were developed to study the transformation of the natural gas-based domestic energy supply system with the introduction of biomethane generation, processing and utilisation based on a range of feedstock and conversion technologies. Biomethane processing includes, among other options considered, the conceptual development of a novel approach for upgrading biogas which utilises existing onshore natural gas processing capacity. Four different objective functions were considered for optimisation, representing different economic and environmental propositions, to identify the best path for introducing biomethane with multiple types of feedstock. Applying these objective functions to UK's domestic energy supply, and assuming a range of subsidies available, it was established that a technically significant displacement of natural gas could be achieved, with displacement capabilities of 48% to 72%, and greenhouse gas (GHG) reductions between 64% and 80%. Economically, these ranges of achievement would correspond to various levels of capital investment and economic viability, depending on the objective functions. Those cases leading to a positive net present value (NPV) appeared to heavily rely on subsidies and could run into a significant loss if subsidies were removed in the operational phase. In contrast, optimisation not assuming any subsidies in the first place could lead to a fundamentally economically viable system, but at the cost of a significantly lower level of biomethane penetration compared to the cases assuming subsidies. Overall, the results have indicated the importance of carefully selecting optimisation objectives, and revealed the potential consequences of adopting financial subsidies in developing the biomethane infrastructure.

KEYWORDS: techno-economic modelling, biogas, bio-SNG, greenhouse gas emission, natural gas

1 INTRODUCTION

Biomethane refers to methane produced from biomass feedstock through industrial processes, including both biogas produced by anaerobic digestion and bio-synthetic natural gas (Bio-SNG) as a product of gasification based thermal processing of biomass. Biomethane offers a renewable alternative to natural

gas and can be produced from a wide range of organic matters. To bring the level of biomethane utilisation to its full potential, it is important to develop a sound understanding of its optimal techno-economic space.

A number of past efforts have attempted to assess biomethane potential for various applications and regions and for different types of feedstock. DECC in the UK (DECC, n.d.) collated information on the economic aspect of biogas including production capital costs and operating costs, production capacities, options for different types of biomethane applications in the UK, as well as subsidies, drivers and barriers to growth; non-optimised modelling was used to analyse various scenarios. Murphy and Power (2008) investigated biogas production in Ireland from three crop rotations: wheat, barley and sugar beet, as a method to meet the European Biofuels Directive which requires the incorporation of biofuels in the transport sector. A more recent assessment of Ireland has been conducted by O'shea et al. (2017), with a focus on cattle slurry and grass silage. Other regional assessments include the work of Tricase and Lombardie (2009) for Italy, focusing on the potential of biogas with animal sewage as feedstock, as well as the work for Sweden on the energy efficiency requirements for a biogas infrastructure (Berglund & Borjesson, 2006) and on economic feasibility of using biogas for transport and district heating (Borjesson and Ahlgren, 2012).

In addition to economic potential, environmental benefits and impacts of biomethane have also been studied. For example, Whiting and Azapagic (2014) established the lifecycle environmental impacts of producing biogas from agricultural wastes by anaerobic digestion to replace natural gas in a Combined Heat and Power (CHP) plant, which demonstrated that up to 50% of the greenhouse gas (GHG) could be reduced, but with higher acidification and eutrophication of 25 and 12 times higher, respectively. Evangelisti et al. (2013) studied the environmental impacts of anaerobic digestion with energy and organic fertilizer production, specific to the Greater London area, UK. In the work of Horschig et al. (2016) on estimating biomethane market potential, greenhouse gas (GHG) emissions for farm-fed and waste-fed systems and different applications were quantified so as to establish their relative contribution to meeting UK and German national GHG reduction targets.

These existing assessments have all focused on specific regions, which are a sensible choice as feedstock availability, potential applications and the policy landscape for biomethane are typically different between various regions. On the other hand, a comprehensive regional assessment would benefit from a study that covers all the important types of feedstock, as opposed to focusing on a subset. Furthermore, given the commercial and public interests associated with biomethane, it is desirable to identify the optimal (as opposed to merely feasible) scenarios for biomethane production and allocation among different sectors against specific objectives, to best inform the relevant stakeholders. Optimisation-based assessment has recently been carried out by Hoo et al. (2017) on the resource potential of palm oil mill effluent (POME) based biomethane production and utilisation in Malaysia. Calderon et al. (2017) have reported a spatially-explicit multi-period mixed integer linear programming (MILP) model, with a mathematical framework that addresses the strategic design of the supply chain in the UK for biomass-derived synthetic natural gas

(bio-SNG) through gasification. Also on bio-SNG, Singlitico et al. (2017) have incorporated geographical information system (GIS) into an optimisation model. Considering anaerobic digestion, Yan et al (2016) have developed multi-objective superstructure optimisation of biomass to biomethane system, focusing on technical and environmental (as opposed to economic) objectives.

In this work, detailed energy flows from the production of biomethane (including both biogas from anaerobic digestion and bio-SNG from gasification), its distribution and use in households alongside natural gas are modelled. The model encompasses a broad range of feedstock and generation routes, as well as a variety of utilisation pathways. In particular, a novel option for biogas upgrading which leverages existing onshore natural gas processing plants is included. Subsequently, respective technical, economic, and carbon emission models for feedstock acquisition, conversion and utilisation are constructed, and an optimisation problem is formulated to identify optimal potential of biomethane as a replacement of natural gas. While the modelling framework is generic, a case study of the UK domestic energy supply market is presented to demonstrate the proposed approach, which particularly emphasises the impact of the choice of objective functions and that of subsidisation.

2 TECHNO-ECONOMIC MODELING OF BIOMETHANE GENERATION AND UTILISATION

2.1 Biomethane production pathways

Various types of feedstock can be used for biomethane generation. As proven in practice, we group feedstock into seven broad categories along their suitability for the two dominant conversion technologies considered, namely anaerobic digestion and gasification, as shown in Table 1 and also in Figure 1.

Table 1: Feedstock Types for AD and Gasification

| Scheme | BIOMETHANE FEEDSTOCK | | | | | | |
|------------------------|-------------------------|---|--------|----------------|----------------|-----------------|---------------|
| | Farm Animal Waste | Municipal Solid Waste/Commercial & Industrial Waste | Sewage | Macro algae | Micro algae | Energy Crops | Wood- chip |
| Anaerobic Digestion | X | X | X | X | X | X | |
| Gasification | | | | | | X | X |

In the matching between feedstock types and conversion processes considered in this work, only energy crops and woodchip are assigned to gasification, in that they relatively possess a low moisture content and a consistent composition, both desirable for efficient production of high-quality biomethane through a thermal route. Note that gasification can potentially be applied also to MSW, although it is not typically considered a conventional feedstock compared to lignocellulosic biomass (Consonni and Vigano, 2012).

However, as technology further develops, new connections between feedstock type and conversion process could become viable and hence should be included in the optimisation model.

As shown in Figure 2, the produced biomethane can be consumed by a centralised CHP facility to produce power exported to the electricity grid and heat for district residential heating. Alternatively, it can be upgraded for injection to the gas grid, to supply the residential sector together with the conventional natural gas through CCGT (combined-cycle gas turbine) based power stations and gas supply to consumers for heating. The upgrading process can take place in either a purpose-built biogas upgrade facility, or, as newly proposed in this work, in an existing onshore natural gas processing plant (see Section 2.1.1 for details). While all the above options apply to the biogas from AD, the high-quality of biomethane from gasification allows it to be directly injected to the gas grid. The suitability of a biomass type for each pathway is determined by their availability and geographical distribution. For instance, the onshore natural gas processing plants are normally located remotely from urban places which, along with comparatively low availability, makes sewage type of feedstock impractical to consider. In contrast, microalgae facilities, with more controllable location and scale, can be tied to the onshore natural gas processing plant. It should be noted that the term “plant” in this paper refers to a plant type which may have multiple installations, as opposed to a specific instance of this plant type.

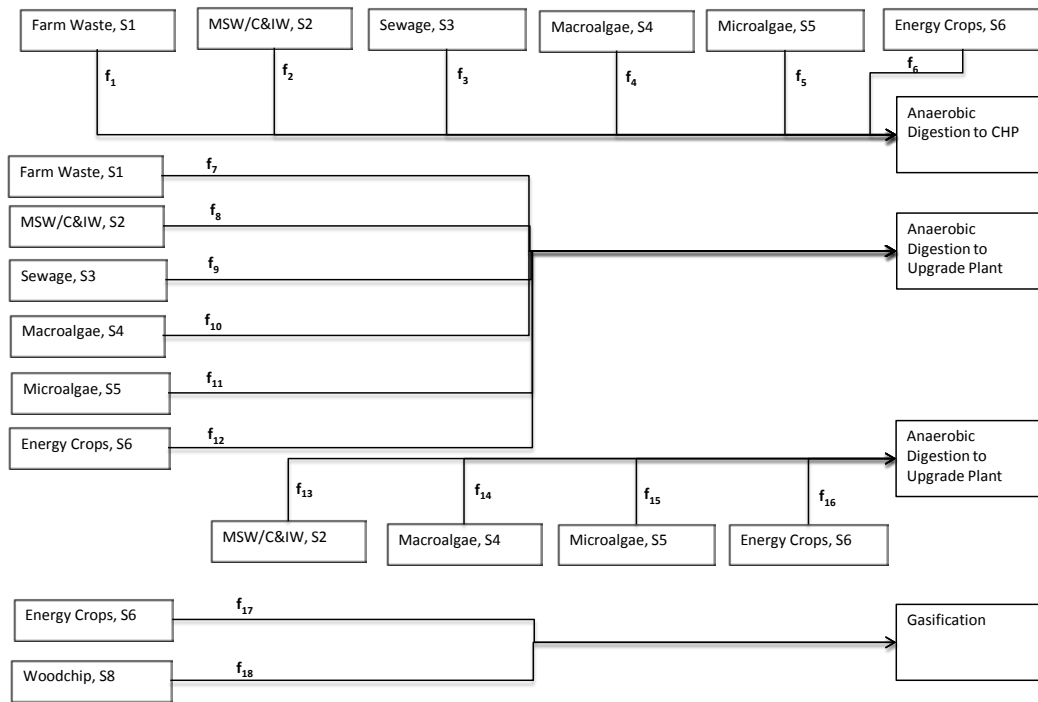


Figure 1: Pathways for feedstock use for energy generation [*MSW = Municipal Solid Waste, C&IW = Commercial and Industrial Waste*].

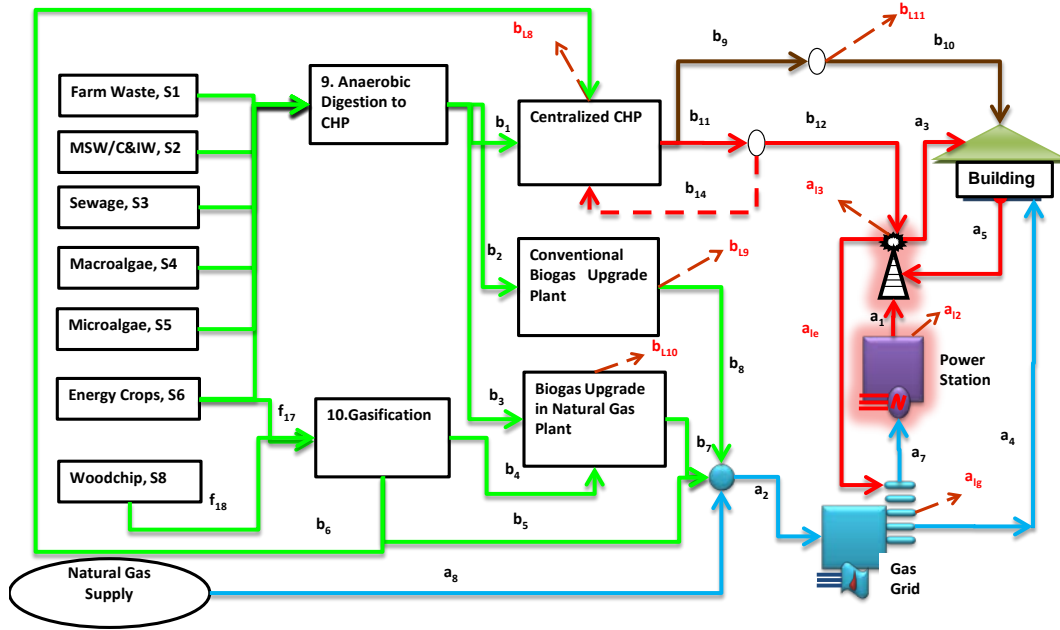


Figure 2: Flow chart for biomethane processing and application.

The energy and material flow and corresponding notation in Figure 1 and Figure 2 are given below:

- a_1 Total electricity supply from the centralised Combined Cycle Gas Turbine (CCGT) power station to the electricity grid
- a_2 Total natural gas and biomethane flow into the gas grid
- a_3 Total electricity supply to the household from the centralised CCGT power station
- a_4 Total natural gas supply to the household from the grid
- a_7 Total natural gas flow from the grid to the centralised CCGT power station
- a_8 Total natural gas supplied
- a_{12} Total energy lost from the centralised CCGT power station in converting gas to electricity
- a_{13} Total amount of energy lost while distributing centralised electricity to households from the electricity grid
- a_{1e} Total amount of electrical energy consumed by the gas grid to various users per unit of gas distributed
- a_{1g} Total amount of gas energy consumed by the gas grid to various users per unit of gas distributed
- b_1 Biogas supply from anaerobic digestion processes to the centralised CHP plant

| | |
|-------------------|---|
| b ₂ | Biogas supply from anaerobic digestion processes to the biogas upgrade plant |
| b ₃ | Biogas supply from anaerobic digestion processes to the onshore natural gas processing plant |
| b ₄ | Bio-SNG supply from the gasification plant to the onshore natural gas processing plant |
| b ₅ | Bio-SNG supply from the gasification plant directly injected into the grid |
| b ₆ | Bio-SNG supply from the gasification plant supplied to the centralised CHP |
| b ₈ | Biogas supply from the biogas upgrade plant to the national gas grid |
| b ₉ | Overall heat energy supply from the centralised CHP plant |
| b ₁₀ | Actual heat delivered to the household from the centralised CHP after accounting for heat losses |
| b ₁₁ | Total electricity supplied from the centralised CHP plant |
| b ₁₂ | Actual electricity delivered to the electric grid from the centralised CHP plant, after deducting internal CHP electricity energy consumption |
| b ₁₄ | Electrical energy consumed by the centralised CHP plant |
| b _{L8} | Energy lost by the centralised CHP plant |
| b _{L9} | Total energy lost and consumed by the biogas upgrade plant |
| b _{L10} | Total energy lost and consumed from the onshore natural gas processing plant |
| b _{L11} | Total heat energy lost during the distribution of heat from the centralised CHP plant |
| f1, f7 | Energy supply from the farm waste feed, <i>kWh</i> |
| f2, f8, f13 | Energy supply from the MSW and C&IW feed, <i>kWh</i> |
| f3, f9 | Energy supply from the sewage-based feed, <i>kWh</i> |
| f4, f10, f14 | Energy supply from the macro-algae-based feed, <i>kWh</i> |
| f5, f11, f15 | Energy supply from the micro-algae-based feed, <i>kWh</i> |
| f6, f12, f16, f17 | Energy supply from the energy crops-based feed, <i>kWh</i> |
| f18 | Energy supply from the wood chips, <i>kWh</i> |

The feedstock-conversion-application pathways are further summarised in Table 2, which exclude unfavourable combinations which can be immediately identified due to geographical unsuitability. It should be mentioned that spatial locations of feedstock and processing facilities are not among the decision variables handled in this work, owing to the difficulties in quantifying the locations of all types of potential feedstock at a national level. Therefore, the optimisation framework developed in this work

should be used for an early-stage screening of combinations of feedstock types, conversion technologies and applications; the superior combinations identified as such could define a narrower scope for a more detailed optimisation model in which further decision factors such as geographical locations can be incorporated. It should also be noted that in this paper, the term “gasification” refers to the route in which biomass is firstly gasified to produce syngas, which is subsequently converted into methane through the methanation process; details of this conversion route can be found in Chen et al. (2017).

Table 2: Possible pathways for biomethane generation and utilisation

| Scheme [Feedstock] | | Biomethane Processing and Utilisation | | | |
|---|-------------------------|---------------------------------------|------------------|-------------------------------------|-----------------------------------|
| | | Centralised CHP | | Biogas upgrade in natural gas plant | Biogas upgrade in dedicated plant |
| | | Heat & electricity | Electricity only | | |
| Farm animal waste | $[f_1, f_7]$ | x | x | | x |
| MSW/C&IW | $[f_2, f_8, f_{13}]$ | x | x | x | x |
| Sewage | $[f_3, f_9]$ | x | x | | x |
| Macroalgae | $[f_4, f_{10}, f_{14}]$ | x | x | x | x |
| Microalgae | $[f_5, f_{11}, f_{15}]$ | x | x | x | x |
| Energy crops for AD | $[f_6, f_{12}, f_{16}]$ | x | x | x | x |
| Energy crops, woodchip for gasification | $[f_{17}, f_{18}]$ | x | x | | |
| | | | | | x |

f_i is the bio-energy obtained from each the conversion process – AD or gasification, i refers to the energy flow being considered, as shown in Figures 1 and 2.

To complete the depiction of biomethane application pathways, Figure 3 represents the household-level energy flows which consist of a gas boiler, a gas boiler heat storage, heating components, an electricity junction box, as well as the point of entry of centralised CHP heat to the household. Here, the electricity supply from the grid, a_3 in Figure 2 feeds in as y_1 in Figure 3. Also, the gas supply a_4 in Figure 2 feeds in as y_3 in Figure 3.

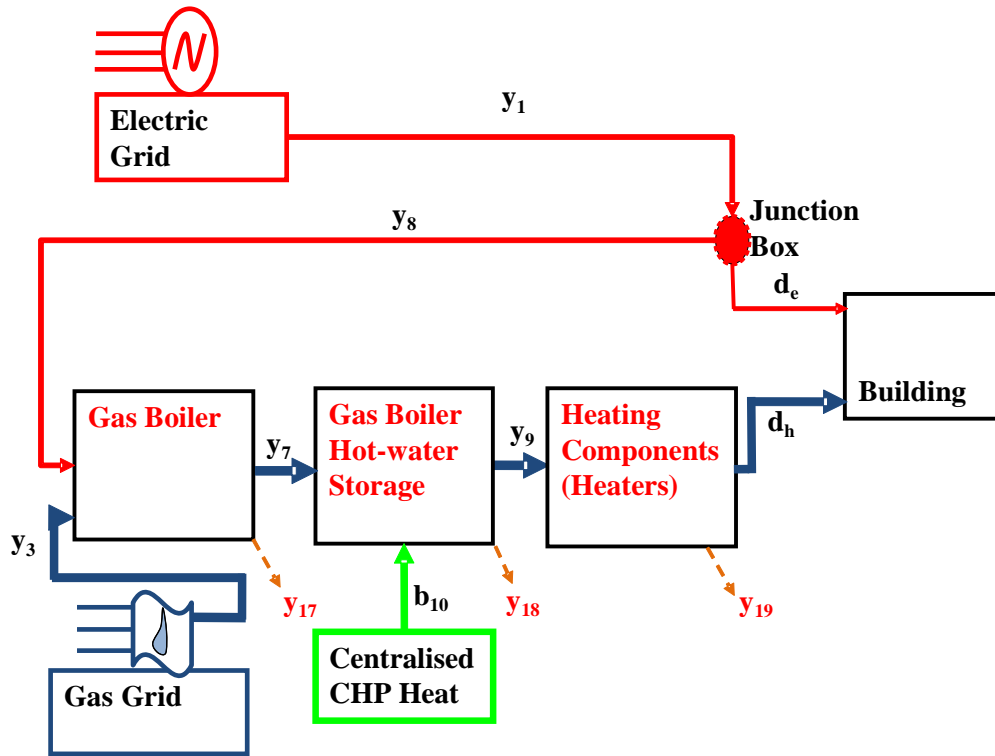


Figure 3: Flow chart for domestic energy supply at the household level.

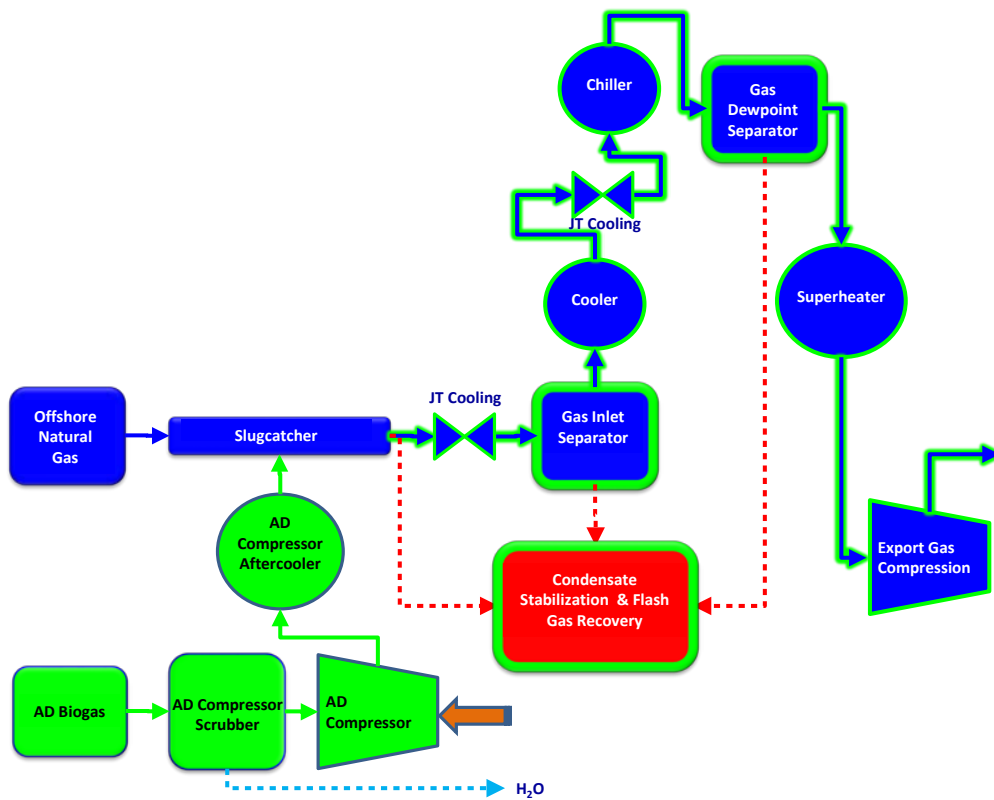
The flows in Figure 3 include:

- d_e Electrical energy demand at the household
- d_h Heat energy demand at the household
- y_1 Electric energy supply to the junction box of the building
- y_3 Fuel energy supply to the gas boiler
- y_7 Thermal energy supply from the gas boiler hot-water storage to the heating components (heater) within the building/heating pipes
- y_8 Electrical energy supply to the gas boiler
- y_9 Thermal energy flow into the heating components
- y_{17} Energy loss from the gas boiler
- y_{18} Energy loss from the gas boiler hot-water storage
- y_{19} Energy loss from the heating components

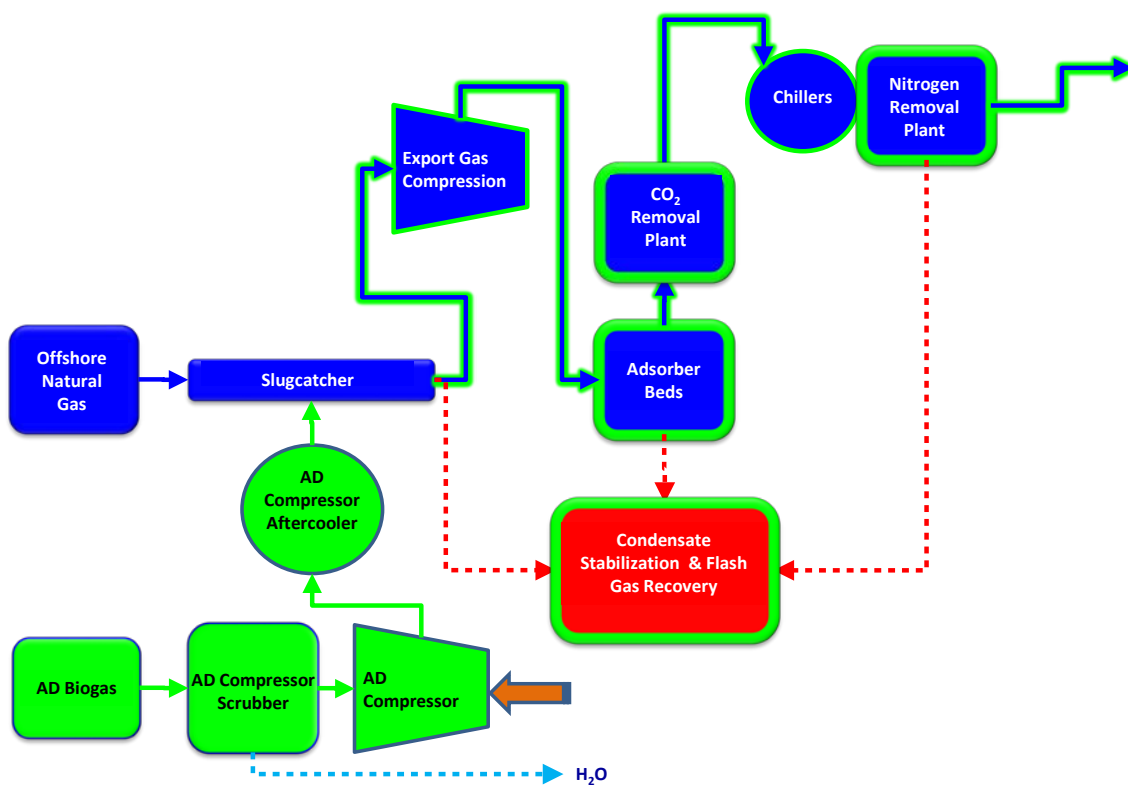
2.1.1 Using existing onshore natural gas processing plants for biogas upgrading

As a novel option, existing facilities for treating natural gas onshore are proposed for upgrading biogas. Conceptual process simulation of actual existing sample natural gas processing plants to upgrade biogas was carried out using Aspen HYSYS to establish the technical feasibility and process efficiency (Fubara, 2016). In this subsection, the flowsheet for each of two different plant configurations typically found in the gas industry is explained. It is worth noting that these conceptual models were based on actual existing plants with real data, but the proposed scheme of treating biogas in such facilities has not been validated by actual plant trials.

The first plant (Figure 4a) treats gas with a high inlet pressure and moisture content, low CO₂ and N₂ and a high calorific value. It receives such a gas feed from an onshore gas processing plant via a slug catcher, which separates the bulk oil and water from the gas stream. Subsequently, the gas is passed through a Joule-Thompson (JT) valve which then reduces the pressure of the gas, and hence its temperature. The gas is then passed to a gas inlet separator which removes any further liquid generated by this cooling process. The partially dry gas is further cooled using a series of coolers, JT valves and chillers to get the gas to sub-zero temperatures. This sub-cooled gas is sent to a gas dewpoint separator to remove any further liquid left in the gas where it meets the hydrocarbon and water dewpoint required to enter the grid. The gas is finally heated up by a superheater and compressed up to the gas grid pressure prior to being injected into the grid.



(a)



(b)

Figure 4: Onshore natural gas plant with two configurations (a and b) as an option for biogas upgrade.

The second plant (Figure 4b) treats drier gas with a lower inlet pressure and high CO₂ and N₂ content, hence a low calorific value. A slug catcher is still used to remove bulk liquid. The gas is then compressed to slightly above gas grid entry pressure, before being sent to the CO₂ removal plants to remove significant amounts of CO₂ from the gas. The adsorber beds are then used where any further water and condensates are removed, so as to meet the gas grid dewpoint entry specifications. A series of chillers and nitrogen removal plants finally remove any significant amount of nitrogen so as to increase the calorific value of the gas before being sent into the grid.

With both types of plant, this work proposes to take biogas from an AD plant, pass it through a scrubber to remove bulk water, and then the biogas is compressed and cooled for entry into the onshore natural gas plant to be processed alongside the rest of the natural gas from the offshore platforms.

2.2 Optimisation problem statement and model overview

In order to identify the maximum potential of biomethane in a national domestic energy supply system, an optimisation problem is solved in this work as an adaptation to that constructed in a previous work (Fubara et al., 2013), to determine the best combination of the options in feedstock types and conversion processes as outlined in Section 2.1, so that the demands for heat and power are met with a mixture of natural gas and biomethane while minimising or maximising a specific economic or environmental objective. Referring to Figures 1 and 2, the solution of the optimisation problem will determine the types and amounts of feedstock to be selected, and the flows through various processing steps, as well as the contributing ratios of biomethane and natural gas (hence the level of displacement) for fulfilling the total demands. The model, developed for the purpose of strategic analysis, considers a period of multiple years with a rather detailed demand profile (using a resolution of one hour), but without accounting for spatial heterogeneity within the analysed region. The model is solved by discontinuous non-linear programming (DNLP) using the BARON solver in GAMS.

Optimisation of energy systems often requires considering a range of objectives. While multi-objective optimisation can be applied to support decisions that simultaneously consider different goals, this work has focused on examining the displacement potential of biomethane under individual objectives or drivers. In particular, four economic and environmental objectives, considering a time period of 20 years, are considered:

- 1) Minimising the total Greenhouse Gas (GHG) generation expressed by CO₂ equivalent in the overall energy supply, G_t ,

$$G_t = \sum_{n=1}^{20} GHG_n(n) - GHG_r(n) - GHG_u(n) \quad (1)$$

- GHG_n Total lifecycle GHG from the Base Case which uses only natural gas for energy generation for the household
- GHG_r Reduced lifecycle GHG attributable to natural gas from the reduced use of natural gas following the introduction of biomethane
- GHG_u Total lifecycle GHG attributable to both the generation and utilisation of biomethane to generate energy for the end-user household, with the boundary covering both the generation and utilisation processes
- G_t Total savings in GHG from replacing energy supply through natural gas with energy supply through biogas and biomethane over a year
- n Year of the assessment

2) Maximising the present value of biomethane infrastructure, **PV_t**,

$$PV_t = PV_c + PV_u + PV_n + PV_g + PV_a \quad (2)$$

- PV_a Net present value (NPV) of introducing AD plants in the energy infrastructure
- PV_c NPV of introducing centralised CHP plants
- PV_g NPV of introducing gasification plants in the energy infrastructure
- PV_n NPV of using an onshore natural gas processing plants to upgrade biogas
- PV_u NPV of introducing biogas upgrade plants

3) Maximising the combined Present Value of the biomethane infrastructure and GHG savings, **PV_{tc}**,

$$PV_{tc} = PV_t + PV_{co} \quad (3)$$

$$PV_{co} = \sum_{n=1}^{20} \left[\frac{C_{cot}(n)}{(1 + r_d)^n} \right] \quad (4)$$

- C_{cot} Total economic gain from savings in GHG in replacing conventional natural gas-based energy supply with biomethane supply
- r_d Discount rate reflecting the expected return on the asset capital
- PV_{co} The present value of GHG savings to the investor in the biomethane infrastructure

4) Maximising the use of biomethane in the overall energy supply and use, **Lh_t**,

$$Lh_t = Lh_a + Lh_g \quad (5)$$

Lh_a Total amount (energy value) of biogas used over the period of assessment

Lh_g Total amount (energy value) of bio-SNG used over the period of assessment

The above objective functions are to be maximised or minimised while satisfying flow balances and operational constraints, provided in Appendix B.

2.3 Economic modelling

Optimisation objectives (2) and (3) introduced above require the determination of net present values, which in turn needs the quantification of costs and revenues across the domestic energy supply chain.

2.3.1 Energy costs

The cost of heat and electricity to the household in year n without the heat supply from the centralised CHP, Co_1 is given as:

$$Co_{weekdays}(n) = \sum_{s=1}^5 \sum_{t=1}^{24} nd(s) \times \left\{ \left(C_e(n) \times a_{3,weekdays}(t,s) \right) + \left(C_n(n) \times a_{4,weekdays}(t,s) \right) \right\} \quad (6)$$

$$Co_{weekends}(n) = \sum_{s=1}^5 \sum_{t=1}^{24} nw(s) \times \left\{ \left(C_e(n) \times a_{3,saturdays}(t,s) \right) + \left(C_n(n) \times a_{4,saturdays}(t,s) \right) + \left(C_e(n) \times a_{3,sundays}(t,s) \right) + \left(C_n(n) \times a_{4,sundays}(t,s) \right) \right\} \quad (7)$$

$$Co_1(n) = Co_{weekends}(n) + Co_{weekdays}(n) \quad (8)$$

where,

$a_{3,saturday}$ Power supply to household on Saturdays

$a_{3,sundays}$ Power supply to household on Sundays

$a_{3,weekdays}$ Power supply to household on weekdays

$a_{4,saturday}$ Gas supply to household on Saturdays

$a_{4,sundays}$ Gas supply to household on Sundays

| | |
|--------------------------|---|
| $a_{4, \text{weekdays}}$ | Gas supply to household on weekdays |
| C_e | Unit cost of electricity |
| C_n | Unit cost of natural gas |
| Co_1 | Overall annual cost of energy supply to the household where there is no centralised CHP heat supply to the household |
| Co_{weekdays} | Overall annual cost of electricity and heat supply from the centralised grid over the weekdays |
| Co_{weekend} | Overall annual cost of electricity and heat supply from the centralised grid over the weekend days, |
| nd | Number of week days in a season |
| nw | Number of weeks in a season |
| t | Hour in the day over which the unit of energy consumed is measured |
| s | Season in the year over which the energy is consumed (five seasons were considered, namely Winter, Spring, Summer, High Summer, Autumn) |

For the case with utilisation of heat from centralised CHP, an additional cost item is introduced:

$$Co_{\text{heat}_{CHP}}(n) = \sum_{s=1}^5 \sum_{t=1}^{24} \left\{ nd(s) \times (m_{10}(n) \times b_{10, \text{weekday}}(t, s)) \right\} + nw(s) \quad (9)$$

$$\times \left\{ (m_{10}(n) \times b_{10, \text{saturday}}(t, s)) + (m_{10}(n) \times b_{10, \text{sunday}}(t, s)) \right\}$$

$$Co_2(n) = Co_1(n) + Co_{\text{heat}_{CHP}}(n) \quad (10)$$

where,

| | |
|---------------------------|--|
| $b_{10, \text{weekday}}$ | Heat supplied to the household from the centralised CHP, on weekdays |
| $b_{10, \text{saturday}}$ | Heat supplied to the household from the centralised CHP, on Saturdays |
| $b_{10, \text{sunday}}$ | Heat supplied to the household from the centralised CHP, on Sundays |
| Co_2 | Overall annual cost of energy supply to the household, including that of the centralised CHP heat supply |
| $Co_{\text{heat}_{CHP}}$ | Overall cost of heat supplied from the centralised CHP to the household |
| m_{10} | Unit cost of heat from the centralised CHP |

The total present cost of energy to the household, PC, is:

$$PC = \sum_{n=1}^{20} \frac{(-C_{o2}(n))}{((1+r)^n)} \quad (11)$$

where,

r Discount rate for the household

n Year of assessment

The total cost comprises a number of cost items including capital costs, tax liabilities, and feedstock costs. The modelling of these costs for relevant system components is summarised in Appendix C.

2.3.2 Revenue streams

A number of revenue streams are available to the system considered, including the sale of energy products and incentives/subsidies. Table 3 indicates revenues from energy sale associated with heat and power from CHP, power from central power plants, and gas from the gas grid that is directly consumed by domestic users (for heating). Based on the current policies in the UK, Table 3 also provides a summary snapshot of which incentives are applicable to each processing unit, including the Enhanced Capital Allowance (ECA), Feed-in-Tariff (FiT), Renewable Heat Incentive (RHI), and the Climate Change Levy (CCL). Note that Renewable Obligation Certificates (ROCs) are another source of incentives that are applicable to large-scale biogas to electricity schemes greater than 5 MW in capacity. Any other scheme between 50 kW and 5 MW can make a one-off choice between ROCs or FiTs. Given the relatively complex arrangement of ROCs, this work considers only FiTs for simplicity of analysis.

Table 3: Mapping of Revenue Streams

| Process System | Revenue from energy sale (Rs) | Applicable economic incentives in the UK | | | |
|---|-------------------------------------|--|-------------|-------------|-------------|
| | | ECA (Rec) | FiT (Rf) | RHI (Rh) | CCL (Rc) |
| AD-based biogas generation units | | | | | |
| Bio-SNG generation | X | | | X | |
| Centralised CHP | X | X | X | X | X |
| Biogas upgrade plant | X | | | X | |
| Biogas upgrade in an onshore natural gas plant | X | | | X | |
| Natural gas supply from the grid | X | | | | |
| Centralised power plant | X | | | | |

In the UK, the Enhanced Capital Allowance provides businesses that invest in given technologies e.g. CHP, with a tax relief in the fifth year, where capital invested in the first year can be written-off the tax liability in the fifth year. The Feed-in-Tariff promotes the uptake of small-scale renewable and low carbon electricity generation technologies by providing a fixed generation and export rate for electricity

fed into the grid from low carbon technologies. The Renewable Heat Incentive is government environmental programme that provides a fixed sum for heat generated from renewable sources. While the Climate Change Levy exemption allows accruable benefits on electricity and gas where they are generated from low carbon sources, with the default that all other energy sources normally have to pay this sum.

The modelling of these revenue streams is summarised in Appendix D.

2.3.3 Summary of the economic model

The key overall economic model equations over the life cycle of the facilities over 20 years of assessment are as given below:

$$PVs_i = Recv_i + \sum_{n=1}^{20} \frac{[(Rf_i(n) + Rh_i(n) + Rc_i(n))]}{(1 + r_d)^n} \quad (12)$$

$$\begin{aligned} PV_i &= -C_i + Recv_i \\ &+ \sum_{n=1}^{20} \frac{[(Rs_i(n) + Rf_i(n) + Rh_i(n) + Rc_i(n)) - (T_i(n) + To_i(n) + Cf_i(n))]}{(1 + r_d)^n} \end{aligned} \quad (13)$$

$$Rs_t = \sum_{n=1}^{20} \{Rs_c(n) + Rs_u(n) + Rs_{ng}(n) + Rs_g(n) + Rs_a(n)\} \quad (14)$$

$$C_t = C_c + C_u + C_{ng} + C_g + C_a \quad (15)$$

$$PVs_t = PVs_c + PVs_u + PVs_{ng} + PVs_g + PVs_a \quad (16)$$

where,

- i Plant type, i = c (centralised CHP), u (conventional biogas upgrade), ng (onshore natural gas processing), g (gasification), a (AD)
- C_a Capital investment cost per household for the AD-based biogas generation plants
- C_i Capital investment per household for plant type i
- C_c Capital investment cost per household for the centralised CHP plants
- C_{f_i} Unit cost of feedstock for plant type i
- C_u Capital investment cost per household for the conventional biogas upgrade plants
- C_{ng} Capital investment cost per household for the onshore natural gas processing plants
- C_g Capital investment cost per household for the gasification-based plants
- C_t Total capital investment for all plant types over the life cycle of assessment
- n Year of assessment

| | |
|------------|--|
| PV_i | NPV of all the investment for the plant type i over the life cycle period of assessment, |
| PV_{S_a} | Total subsidy contribution to the NPV for the anaerobic digestion-based biogas generation |
| PV_{S_c} | Total subsidy contribution to the NPV for the centralised CHP |
| PV_{S_g} | Total subsidy contribution to the NPV for the gasification plants |
| PV_{S_i} | NPV of the subsidies for the plant type i over the life cycle period of assessment |
| PV_{S_n} | NPV of total subsidy contribution to the NPV for the onshore natural gas processing plants |
| PV_{S_t} | NPV of subsidies for all the plant types over the life cycle period of assessment |
| PV_{S_u} | NPV of total subsidy contribution to the NPV for the conventional biogas upgrade plants |
| Rc_i | Climate Change Levy Exemption for plant type i |
| rd | Discount rate reflecting the expected return on the asset capital |
| $Recv_i$ | Present value of the Enhanced Capital Allowance for plant type i , |
| Rf_i | Annual Feed-in-Tariff for any of plant type i |
| Rh_i | Annual Renewable Heat Incentive for plant type i |
| Rs_a | Annual revenue from the sale of energy products from the AD biogas generation plants |
| Rs_c | Annual revenue from the sale of energy products from the centralised CHP |
| Rs_g | Annual revenue from the sale of energy products from the gasification plants |
| Rs_n | Annual revenue from the sale of energy products from the onshore natural gas processing plant in processing biogas |
| Rs_u | Annual revenue from the sale of energy products from the conventional biogas upgrade plants |
| Rs_t | Total revenue from all plant types over the life cycle of assessment |
| T_i | Annual tax liability for plant type i |
| To_i | Annual operating costs for plant type i |

The equation for PV_i underpins the objective function of maximising the present value of biomethane infrastructure CAPEX, as introduced earlier by equation (2) in Section 2.2. The other three economic quantities, C_t , PV_{S_t} and Rs_t , are used to determine respectively the total CAPEX required to introduce the optimal biomethane infrastructure, the sales revenues from this new infrastructure and incomes through subsidies.

2.4 GHG balance for biomethane Introduction into the domestic energy supply system

The purpose of GHG balance for the introduction of biomethane into the domestic energy supply system is to quantify GHG reduction compared to the base case system that uses natural gas only. All literature data on GHG emission were collated from sources that applied a cradle-to-grave approach. For each

process unit, this therefore covers the GHG embedded in its feedstock and the direct GHG emissions from that unit.

The GHG emission by the base system, GHG_n , is calculated by

$$GHG_n = (GH_e \times y_1) + \left(GH_h \times \frac{d_h}{E_{st}} \right) \quad (17)$$

where,

| | |
|----------|--|
| d_h | Total household boiler fuel gas demand for the generation of heat |
| E_{st} | Percentage of the thermal energy supplied from the boiler with respect to the fuel energy supplied to the boiler |
| GH_e | Base case (natural gas energy network) lifecycle GHG of unit electricity supply (to household) from natural gas-fired CCGT |
| GH_h | Base case (natural gas energy network) lifecycle GHG of unit heat supply from natural gas –fired boiler |
| y_1 | Total electricity supply to the household from the centralised power plant |

In the system incorporating a biomethane infrastructure, the part of the energy supply from biomethane introduces the following GHG emission:

$$GHG_u = GHG_a + GHG_g + GHG_{10} + GHG_{11} + GHG_{12} + GHG_{13} + GHG_{14} \quad (18)$$

where,

| | |
|------------|---|
| GHG_a | Lifecycle GHG attributable to all the AD biogas generation processes |
| GHG_g | Lifecycle GHG attributable to all the gasification-based generation processes |
| GHG_{10} | Lifecycle GHG associated with the use of the centralised CHP |
| GHG_{11} | Lifecycle GHG associated with the use of the biogas upgrade plant |
| GHG_{12} | Lifecycle GHG associated with the use of the onshore natural gas processing plant for upgrading biogas |
| GHG_{13} | Lifecycle GHG associated with the use of the biomethane for producing electricity from centralised power plant and supplying household through the electricity grid |
| GHG_{14} | Lifecycle GHG associated with the use of the biomethane for supplying heat to household through the gas grid |

In such a system, biomethane complements natural gas; the latter's GHG emission, reduced from the base case due to the partial displacement by biomethane, is

$$GHG_r = [(GH_e \times a_1 \times E_{ed}) + (GH_h \times a_4)] \times \varphi_r \quad (19)$$

where,

E_{ed} Efficiency of the centralised electricity distribution system

φ_r Fraction of natural gas in the total gas supply through the gas grid, determined by a_8/a_2 according to Figure 2

Comparing the GHG emission from the base case and the combined emission from biomethane and natural gas in the new system, the GHG reduction by incorporating the biomethane infrastructure can be determined:

$$GHG_s = GHG_n - GHG_r - GHG_u \quad (20)$$

If the terms in the above equation are all for single years, summing up GHGs over the entire period of assessment will give the total GHG savings, i.e. G_t which was introduced earlier as one of the optimisation objectives in Section 2.2 (equation (1)). Assigning a unit price for GHG emission, C_{co2} , the cost savings from GHG reduction for year n (used in equation (4)) becomes

$$C_{cot}(n) = C_{co2} \times GHG_s(n) \quad (21)$$

3 CASE STUDY OF THE UNITED KINGDOM DOMESTIC ENERGY MARKET

The case study is on the UK domestic energy supply chain based on natural gas, with a base case consisting of centralised power generation through CCGT, and the household gas boilers running on natural gas for heat generation. The aim of the case study is to establish the various optimal routes for introducing biomethane production and conversion into the current system, and hence the potential for replacing natural gas with biomethane.

3.1 UK domestic energy market

The total UK gas demand stood at 97 billion m^3 /year in 2009, while the domestic gas demand stood at 35 billion m^3 /year (National Grid, 2009), implying that the domestic gas demand is about 36.1% of the national demand. The Digest of UK Energy Statistics (DUKES) report for 2012 put the total domestic energy natural gas consumption at 339.1 TWh against a total natural gas supply of 999.7 TWh, implying that the domestic natural gas use was 33.9% of the total natural gas supply (UK Government, 2012). It is also worth noting that Department of Energy and Climate Change (DECC) has stated that about 36% (DECC, 2013) of the total primary energy demand in the UK is satisfied by natural gas, which is about

951.8 TWh/year. Out of this, the UK produces about 395 TWh of electricity every year and also imports 5 TWh, implying a total electricity consumption rate of 400 TWh/year (Martinez-Perez, et al., 2006).

3.2 Key assumptions and data collection

The following assumptions are made for this study based on key facts and also to clearly define the basis of the analysis:

- A typical lifetime of 20 years was assumed for the various plants (Melin, 2011).
- Depreciation is assumed to be linear over 20 years of the life of the investment.
- The parasitic energy (heat and/or electricity) requirement within the plant is met by the plant itself.
- The revenue from the sale of energy product (biomethane) for the anaerobic digestion based system of biomethane generation is zero. Biomethane is only regarded as saleable when it is upgraded to natural gas quality.
- Base Case refers to the UK domestic energy supply system based on natural gas.
- The unit price of clean biomethane which is injectable to the grid will assume the same unit price per kWh as that of the wholesale price of natural gas in the market.
- There is currently no actual price for heat from centralised CHPs in the UK, therefore a hypothetical price has been adopted based on literature analysis (Zglobisz et al., 2010; Dave, et al., 2013).

Completion of this case study required a large amount of data, which have been collated from multiple literature sources. As a summary, these data include:

- Energy efficiency figures at the household level, including that the boiler, heat storage, radiator;
- Energy efficiency figures at the energy network level, including the electrical efficiency of the electric grid system, the efficiency of the gas distribution network and of the central power plants;
- Economic data including applicable corporation tax, discount rates, feed-in-tariff, renewable heat incentives and climate change levy rates;
- Technical data for each biomethane generation system, including feedstock productivity/generation rate, calorific value of each type of biomethane based on feedstock, biomethane potential/yield from each feedstock, cost of each feedstock, and market potential in the UK;
- Greenhouse gas emission for each biomethane feedstock, electric supply from the grid, natural gas supply from the grid, biogas upgrade process, centralised CHP, and upgrade of biogas in an onshore natural gas processing plant.

Detailed data tables used in this work are given in Appendix A.

4 RESULTS AND DISCUSSION

The system that incorporates a biomethane infrastructure into UK's domestic energy supply has been optimised. In this section, results from applying various objective functions are presented first. In these optimisations, government subsidies as presented in Section 2.3, which are available in the UK, have been included in the model, however they are policy dependent and may be unavailable in other cases. In the second part of this section, the implication of government subsidies to the deployment of a biomethane infrastructure is analysed. Note that our work has analysed both the case with and that without the utilisation of CHP heat (Fubara, 2016); the results reported in this paper have however focused on the former which is considered sufficient for demonstrating the approach.

4.1 Optimisation results and key observations

Tables 4 and 5 summarise the key output from the modelling analysis. All optimisation criteria resulted in a technically significant displacement of natural gas from the UK domestic energy supply system, with displacement capabilities of 48% to 72%. In comparison, earlier work carried out by the National Grid stated that about 48% of the UK natural gas demand could be met by AD and gasification, with projections that 50% of the UK domestic natural gas demand can be met by this renewable gas in the future (National Grid, 2009). To the contrary, DECC carried out future scenarios for biomethane potential where they stated that only 3-5 TWh/year or ~0.5% of the UK natural gas demand could be produced in the UK by 2020 (EUA, 2012). The value of the proposed approach in this work lies in allowing the decision makers to explore the biomethane potential via optimisation with diverse objectives, which can identify the range of potential as achievable if the system was to be developed with different drivers. On GHG reductions, the optimisation results suggest a range of 64% to 80%. In absolute values, the introduction of biogas will result in a CO₂ reduction of 2.45 – 3.04 tonnes CO₂e/household/year with a CO₂ cash value savings of £314 – 389 /household. This is achievable with a capital investment of £5,275 – £17,328 per household to set up the biomethane architecture (£143 billion - £470 billion based on 27.1 million households in the UK). The NPV from this investment over a 20-year lifecycle when optimised against various criteria, ranges from a profit of £6,407 to a loss of £8,539 per household.

Table 4: Potential techno-economic potential of biomethane in UK's domestic energy supply (with subsidies)

| | UNITS | BASE CASE | BIOMETHANE + NATURAL GAS | | | |
|--|-----------------------------|-----------|--|--|---|--|
| | | | <i>Maximising the present value of biomethane infrastructure and GHG savings, PVtc</i> | <i>Maximising the present value of biomethane infrastructure only, PVt</i> | <i>Maximising the total GHG savings, Gt</i> | <i>Maximising the use of biomethane, Lht</i> |
| NPV of introducing biomethane architecture, PVt | £/household | 0 | 6,075 | 6,047 | -3,214 | -8,858 |
| NPV of introducing biomethane architecture and GHG savings, PVtc | £/Household | - | 6,407 | 6,362 | -2,825 | -8,539 |
| Present value of subsidy/incentives by government, PVst | £/Household | 0 | 8,573 | 8,356 | 7,331 | 7,257 |
| Total capital investment for introducing bio-energy architecture, Ct | £/Household | 0 | 5,560 | 5,275 | 12,603 | 17,328 |
| Total GHG savings per household per year, GHGs (g CO ₂ e) | (g CO ₂ e) | - | 2.590E+06 | 2.455E+06 | 3.035E+06 | 2.488E+06 |
| % Reduction in GHG emission from Base Case position | % GHG reduction / household | - | 68% | 64% | 80% | 65% |
| Annual revenue from GHG savings through bio-energy products, PVco | £/Household | - | 332 | 314 | 389 | 319 |
| Annual revenue from sale of bio-energy products, Rst | £/Household/yr | - | 779 | 750 | 667 | 616 |
| Annual consumption of natural gas, Pet | kWh/Household | 26,242 | 11,493 | 11,870 | 13,614 | 7,257 |
| % Displacement of natural gas | % | - | 56.20% | 54.77% | 48.12% | 72% |

Table 5: Technical structure of potential biomethane systems for UK's domestic energy supply (with subsidies)

| UNITS | | BIOGAS + NATURAL GAS | | | |
|--|-----------------------------|---|--|---|--|
| | | <i>Maximising the present value of biomethane infrastructure and GHG saving, PVtc</i> | <i>Maximising the present value of biomethane infrastructure only, PVt</i> | <i>Maximising the total GHG savings, Gt</i> | <i>Maximising the use of biomethane, Lht</i> |
| Total amount of energy generated by the AD plants, Lha | <i>kWh / Year/Household</i> | 12041.12 | 12564.26 | 8440.74 | 8607.70 |
| Total amount of energy generated by the gasification plants, Lhg | <i>kWh / Year/Household</i> | 1652.86 | 742.68 | 3932.68 | 4571.92 |
| Total amount of electricity produced by the centralised CHP, Lec | <i>kWh / Year/Household</i> | 2370.18 | 2321.90 | 2159.52 | 1486.70 |
| Total amount of heat produced by the centralised CHP, Lhc | <i>kWh / Year/Household</i> | 1983.21 | 1942.82 | 1806.95 | 1243.98 |
| Total amount of energy processed by the biogas upgrade plant, Lhu | <i>kWh / Year/Household</i> | 416.39 | 314.64 | 2176.98 | 3296.99 |
| Total amount of energy processed by the onshore natural gas processing plant for biogas upgrade, Lhn | <i>kWh / Year/Household</i> | 6302.60 | 6815.59 | 440.09 | 551.48 |

Comparison of results between the cases with different objective functions reveals some shared features in the solutions as well as a number of key differences. In all the cases analysed, AD always presented a greater potential in terms of total energy supply than gasification, due to the higher feedstock availability of the former. Also, only the case of maximising the biomethane supply showed the minimum use of centralised CHP. The conventional biogas upgrade option was sparsely selected when NPV was part of the optimisation criteria. The use of the onshore natural gas processing plant for upgrading biogas reaches the highest level of 6,815 kWh/year/household (185 TWh/year nationally) processed when the combined NPV for GHG savings and investment returns is maximised as an objective function, compared to 441 kWh/year/household (12 TWh/year nationally) when the GHG reductions are maximised. This suggests that the use of the onshore natural gas processing plant to upgrade biogas is most favourable when maximising the combined economic and environmental benefit than when maximising the GHG savings alone. Also, AD biogas generation was increased, and gasification reduced when only the NPV of the biomethane infrastructure was the optimisation objective as compared to when the combined NPV was the optimisation criterion. This implies that there are economic and environmental trade-offs between these two types of biomethane streams.

Interestingly, a system that maximises GHG reduction leads to a rather low level of displacement of natural gas compared to the other cases, as the model and its parameterisation entail that further displacement of natural gas would invoke the deployment of certain type(s) of biomethane production with a high GHG footprint which overweighs the GHG reduction achievable by the further displacement of natural gas. Given the disparity between the intuitive expectation from applying a specific objective function and its actual consequence, a careful choice of the objective function will need to be made when developing a biomethane roadmap.

Finally, the solution to the optimisation model corresponding to each objective function determines the selected quantities of feedstock, with Figure 5 showing the Sankey diagram for the system energy flows when the combined present value of the biomethane infrastructure and GHG savings (PV_{tc}) is maximised.

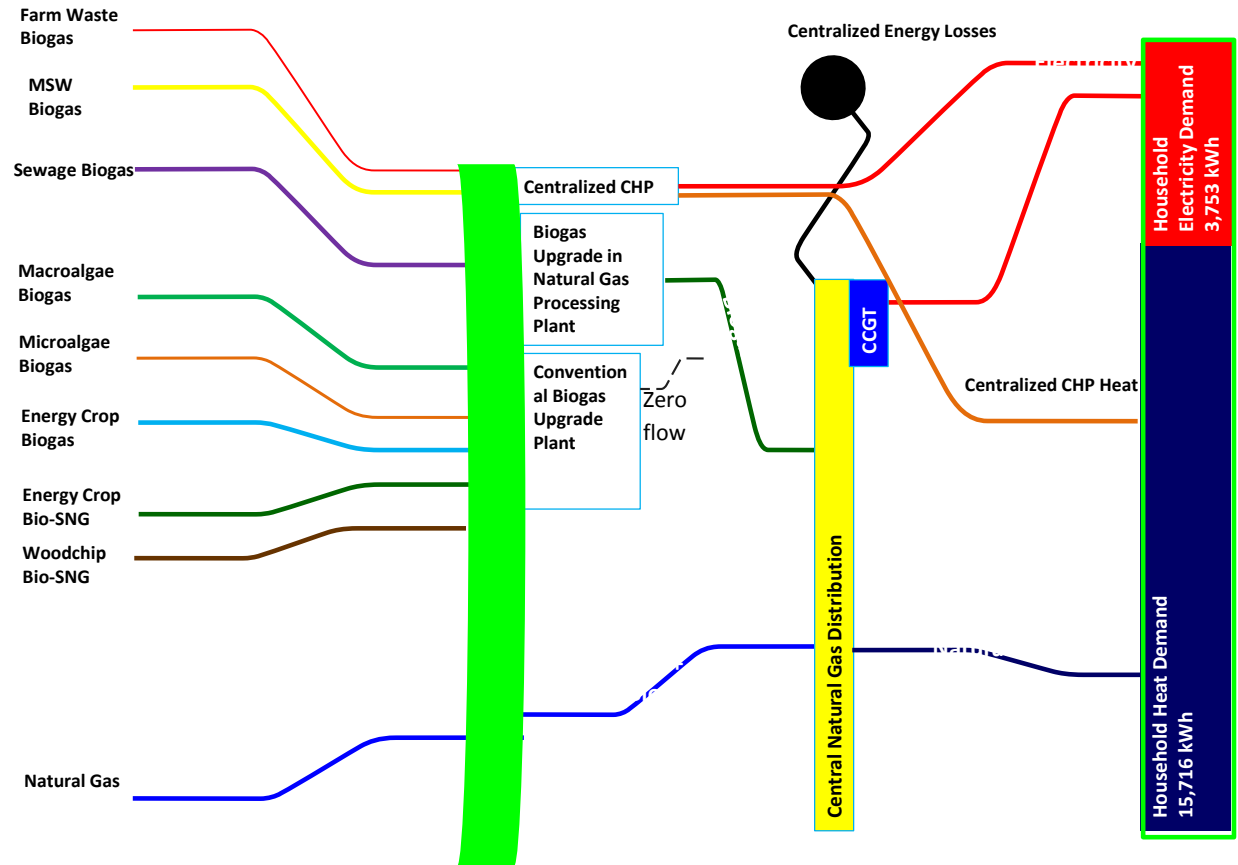


Figure 5: Sankey diagram for the energy flows in a system optimised for maximising the combined present value of the biomethane infrastructure and GHG savings (PV_{tc}): the case with subsidies.

4.2 Implications of governmental subsidies

In a free market economy, the use of subsidies to support an energy policy creates an artificial price for a product and may affect the development of a sector in various ways. Where these subsidies are applied (including Renewable Heat Incentive, Climate Change Levy, Feed-in-Tariff in the case of the UK, the maximum combined NPV of biomethane infrastructure and GHG savings reaches £6,407 per household, which however comes with subsidies at a present value of £8,573 per household. The relative proportions of the three income streams are shown in the outer pie chart in Figure 6, where the inner pie chart shows the relative sizes of capital investment and operating costs against the total income, all in terms of the present value over a 20 years period. It can be clearly seen that such a system will be operating at a significant loss, if the subsidies ceased to exist, indicating the potential risk of establishing the

biomethane roadmap with a heavy dependence on subsidies, the implementation of which may suffer from changes of policies.

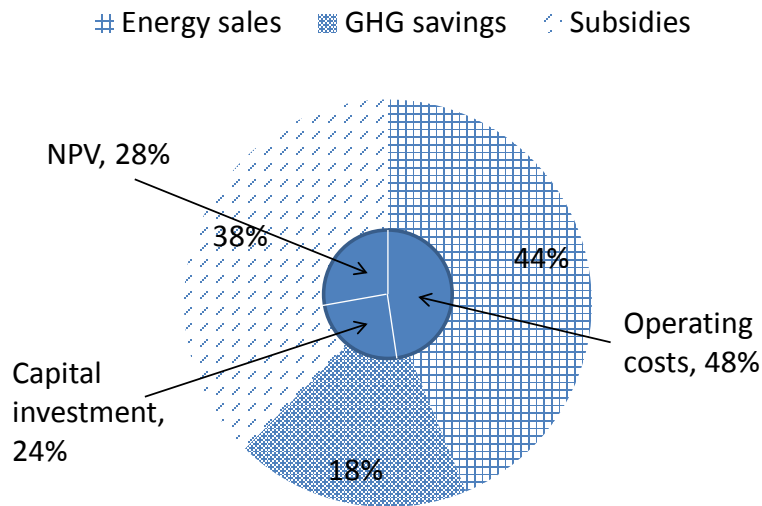


Figure 6: Proportions of present values of revenues and costs over 20 years when maximising PVtc (combined NPV of biomethane infrastructure and GHG savings) with subsidies.

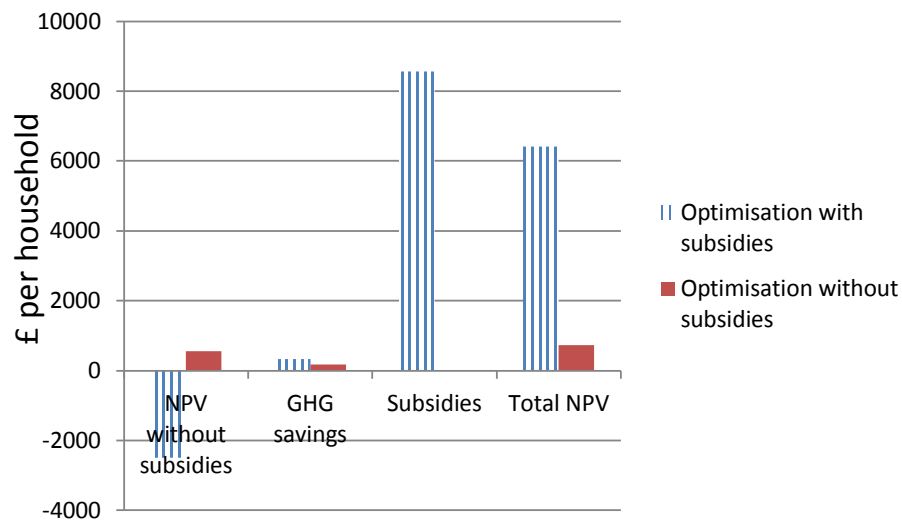


Figure 7: Effect of subsidies on the NPV for introducing biomethane: results of maximising PVtc (combined NPV of biomethane infrastructure and GHG savings).

To the contrary, where subsidies are entirely not considered in the planning phase, and the system optimised on this basis, the introduction of biomethane could become a truly profitable business venture, as shown in Figure 7 where the optimal criterion is to maximise the combined NPV of the biomethane infrastructure and the GHG savings. Based on the parameters and assumptions adopted in this study, this result suggests that it is possible for a biomethane infrastructure to be set up with true economic viability without the need for subsidies. If a system following one of these economically favourable designs is actually implemented, any introduction of subsidies during its operation will only further improve its profitability and enhance its economic robustness.

It should be emphasised that, the improved economic viability identified by planning without subsidies is at the cost of a significant reduction in the level of biomethane penetration: For the same objective function of maximising the combined NPV of the biomethane infrastructure and GHG savings, the natural gas displacement potential of biomethane reduces from 56% where subsidies are applied to 17% without subsidies applied (detailed results for the latter are not shown). Comparing the energy flow scenario for the case with subsidies applied (as shown in Figure 5) and that without any subsidies applied (as shown in Figure 8), applying subsidies allows the development of a greater capacity of gasification. In particular, energy crop and woodchip feedstock generation volumes were significantly increased where subsidies were applied. For AD biogas generation, its total capacity also increases noticeably with subsidies applied, primarily due to the increased adoption of macroalgae, sewage, and energy crop feedstock. These changes suggest that the assumed availability of subsidies can alter the size, structure as well as economics of the proposed optimal biomethane infrastructure.

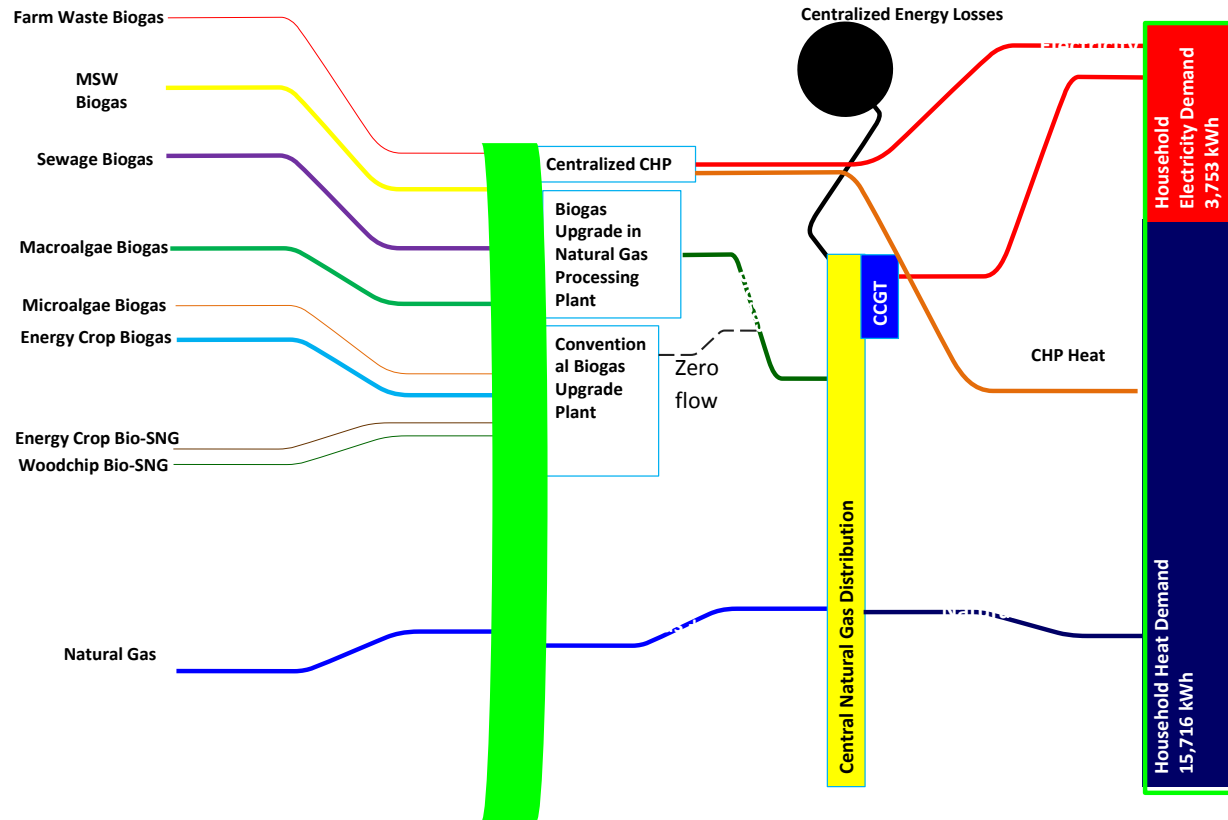


Figure 8: Sankey diagram for the energy flows in a system optimised for maximising the combined Present Value of the biomethane infrastructure and GHG savings (PV_{tc}): the case without subsidies.

4.3 Limitations of this work

As an effort of strategic screening, this work contains a number of limitations. In particular:

- The mathematical modelling does not take into consideration barriers to technology development other than technical and costs barriers.
- The effect of feedstock availability and variation, competing feedstock usage, as well as other spatial and temporal feedstock variability has not been included.
- Effects of geographical locations of the raw materials and the processing facilities, and the related logistics operations, have not been modelled.
- The effect of economies of scale, learning curve, and other wider policy drivers have not been taken into consideration.

-
- Further economic benefits from the sale of digestate and other by-products produced from each of the processing units considered in this study, have not been assessed. More generally, interconnections with wider systems such as the whole energy-food-water nexus have not been considered.
 - All calculations are done for a steady-state system, therefore no heat accumulation over time in domestic household boilers or any other centralised thermal storage is considered.
 - The model has focussed on the replacing the domestic energy natural gas supply only, and has therefore not taken into consideration any specific grid constraints arising from increased energy flow through the gas grid or the electricity grid.
 - In assessing the GHG-reduction potential of biomethane generation and utilisation, parameters were obtained by collating data from multiple sources, where the reliability in the stated boundaries and data quality inevitably vary despite the intended cradle-to-grave scope, which may have affected the results of this current study.

5 CONCLUSIONS

In this work, a comprehensive model was developed for assessing the technological entry paths for biogas and bio-SNG into the sector of domestic energy supply. An optimisation approach was adopted to identify the best combination of feedstock and technical options corresponding to each one of the four objectives that represent different economic and environmental perspectives.

When applied to a case study of the UK, it was shown that all optimisation criteria resulted in a technically significant displacement of natural gas from the UK domestic energy supply system, with displacement capabilities of 48% to 72%, and GHG reductions ranging from 64% to 80%. This demonstrates that the proposed approach allows the decision makers to explore the biomethane potential via optimisation with diverse objectives, which can identify the range of potential as achievable if the system was to be developed with different drivers. The results of the case study also revealed that increase in biomethane introduction and decrease in GHG do not necessarily occur hand-in-hand, due to the differences in the GHG footprint between biomethane pathways. This suggests the importance of carefully choosing the optimisation target so that planning decisions can achieve the desired outcome.

Economically, the range of achievement in natural gas displacement and GHG reduction would correspond to various levels of capital investment and economic gains or losses, depending on the

objective functions. For a system that maximises the net present value (NPV) of both the capital investment and the economic savings from GHG reduction, a capital investment of £5,560 per household (£150 billion for the country) would be needed to set up the biomethane architecture that has the potential to displace natural gas consumption by 56% and to reduce GHG emission by 64%, with an NPV over a 20-year lifecycle of £6,407 per household (£174 billion for the country). Such a positive economic outlook would however dramatically deteriorate to an inviable level, if subsidies were removed in the operational phase. In contrast, an optimal design not assuming any subsidies in the first place could lead to a fundamentally viable system, but at the cost of a much lower level of biomethane penetration compared to the case assuming subsidies. This implies that financial policy instruments need to be carefully chosen, possibly through a rational combination of subsidies and carbon tax.

APPENDIX A: TECHNICAL / ECONOMIC DATA SELECTION FOR THE UK CASE STUDY

There was significant disparity in the data sets from literature, and therefore nominal values representing the most probabilistic value was selected to be used.

Table A1: Energy Efficiency Parameters – Household Level and Network Level

| Parameter | Value |
|--|---------|
| <u>Efficiency at the household level</u> | |
| Boiler, E_{st} (Carbon Trust, 2011) | 0.85 |
| Boiler heat storage, E_{bt} | 1 |
| Radiator, E_{ht} | 1 |
| Electricity consumption of boiler as a fraction of the heat generated by the boiler, B_e | 0.0125 |
| Electricity consumption by the boiler pump, y_8 (kWe) (Cho, et al., n.d.) | 0.0625 |
| <u>Efficiency at the network level</u> (National Grid, 2011) | |
| Electricity distribution system efficiency, E_{ed} | 0.95 |
| Efficiency of gas distribution, in electricity consumed per kwh energy distributed, E_e | 0.00298 |
| Efficiency of gas distribution, in gas consumed per kwh energy distributed, E_g | 0.00066 |
| Central power plant (CCGT) efficiency, E_{pp} | 0.55 |

where E_{st} is the percentage of thermal energy supplied from the boiler with respect to the total fuel energy (natural gas) supplied to the boiler.

Key efficiency values for the various units both at the household energy distribution level and the network level were established, and are as shown in Table A1. The economic parameters for economic modelling for the case study of the UK energy supply chain, including tax rates and values for incentives/subsidies, are as shown in Table A2.

Household energy use data was obtained from the UK Energy Research Council (UKERC, 2011), and a typical average 4 Bedroom household data was used. The 4-bedroom household size used on the basis that it provides an average use profile when compared to the 2, 3, and 5 bedroom properties studied.

Table A2: Key Economic Data

| Parameter | Symbol | Value |
|-----------------------------|----------|--------------|
| Corporation Tax | T_c | 21% |
| Feed-in-Tariff (Generation) | R_{f1} | £0.0896/kWh |
| Feed-in-Tariff (Export) | R_{f2} | £0.0450/kWh |
| Renewable Heat Incentive | R_h | £0.071/kWh |
| Climate Change Levy | R_c | £0.00182/kWh |
| Discount Rate | r_d | 4.7 |

Data was collected for the biomethane potential for various feedstock, as well as the calorific value of the gas, in addition to the maximum market potential in the UK as a case study. Also defined were the parasitic energy consumption of each unit, investment and operating costs for each unit, and the GHG emissions of each unit. These are defined in Table A3 and Table A4. Also, in quantifying the GHG emission in this study, lifecycle footprint using the cradle to grave approach was considered – from the extraction of natural gas from the reservoirs and the generation of biomethane to the supply point to the household. The key references for determining the range of literature values for these various data are as shown in Table A6.

Table A3: Literature Data Collated for Different Feedstock for Biomethane Generation*

| Feedstock | Unit | MS W/C &I | Farm Animal Waste | Energy Crops | Macro -Algae | Micro -Algae | Waste water sludge | Woodchip for Gasification |
|-------------------------------|-------------------------------------|------------------------------|----------------------------------|-------------------------|-------------------------|-------------------------|-----------------------------------|--|
| Calorific value of Biogas | <i>kWh/m³</i> | 5.83 | 6.5 | 5.83 | 5.07 | N/A | 6.73 | 10 |
| Biomethane Potential/Yield | <i>kWh/Tonne</i> | 650 | 400 | 2000 | 350 | 700 | 2000 | 3000 |
| Cost of Feedstock** | <i>£/Tonne</i> | -50 | 8 | 70 | 400 | 300 | 0 | 90 |
| Feedstock availability*** | <i>% of total energy demand</i> | 3.20 | 4.00 | 40 | 26 | 13 | 40 | 30 |

* Data sources used in this work are summarised in Table A6.

** Note that transportation costs for feedstock are adequately represented in the cost of the individual feedstock, on the premise that the plants have been optimally sited.

***This refers to the UK case with reference to domestic energy demand, determined based on the estimated available tonnage per year, biomethane yield, and calorific value of biogas.

Table A4: GHG emission data of feedstock provision and processing

| System | Unit | Selected value |
|---|--|-----------------------|
| Farm Animal-Waste | $g\ CO_2e/kWh_{biomethane}$ | 75 |
| MSW | $g\ CO_2e/kWh_{biomethane}$ | 15 |
| Sewage | $g\ CO_2e/kWh_{biomethane}$ | 5 |
| Macro-Algae | $g\ CO_2e/kWh_{biomethane}$ | 30 |
| Micro-Algae | $g\ CO_2e/kWh_{biomethane}$ | 75 |
| Energy Crops | $g\ CO_2e/kWh_{biomethane}$ | 50 |
| Woodchip | $g\ CO_2e/kWh_{biomethane}$ | 50 |
| Natural Gas-Fired Electricity | $g\ CO_2e/kWe$ | 900 |
| Average UK Electricity Mix | $g\ CO_2e/kWe$ | 850 |
| Natural Gas-Fired Heat Supply | $g\ CO_2e/kWh_{heat\ supplied}$ | 14 |
| Biogas Upgrade | <i>GHG as a % of feed biogas GHG</i> | 30 |
| Centralised CHP | <i>GHG as a % of feed biogas/bio-SNG</i> | 70 |
| Upgrade in an onshore Natural Gas Plant | <i>GHG as a % of feed biogas GHG</i> | 30 |

C_{co2} is the unit cost of CO_2 taken as £16/Tonne CO_2 (0.016p/g CO_2e) (Ares, 2014).

Assuming that 50% of the overall GHG from literature for a biogas process is linked to generation, Table A4 provides the factor of that 50% GHG from generation, which is equivalent to that for the upgrade and utilisation processes.

Table A5: Data for individual plant types (energy consumption and economic costs)

| Feedstock | Unit | Biogas plant | Bio-SNG plant | Conventional biogas upgrade plant | Onshore natural gas processing plant for treating biogas | Centralised CHP | Centralised CCGT |
|-------------------------|-------------------------------------|--------------|---------------|-----------------------------------|--|-----------------|------------------|
| Plant Life | <i>Years</i> | 20 | 20 | 20 | | 20 | 20 |
| Elect. Energy Consumed | $kWh_{consumed}/kWh_{gas-feed}$ | | | | | 5 | 55 |
| Heat Energy Consumed | $kWh_{consumed}/kWh_{gas-feed}$ | | | | | 52 | |
| Total Energy Consumed | $kWh_{consumed}/kWh_{gas-feed}$ | 0.550 | 0.40 | 0.300 | 0.012 | | |
| Electrical Efficiency | <i>% of Biogas Feed</i> | | | | | 49 | |
| Thermal Efficiency | <i>% of Biogas Feed</i> | | | | | 41 | |
| Heat Distribution Loss | <i>% of heat supplied</i> | | | | | 20 | |
| Max. Biogas Injection | $kWh_{biogas} : kWh_{natural\ gas}$ | | | | 1:1 | | |
| Capital Investment Cost | $£/kW_{capacity}$ | 1000 | 1000 | 800 | 15 | 2150 | |
| O&M Costs | <i>% of CAPEX</i> | 10 | 9 | 8.00 | 2.00 | 1.81 | |

Table A6: Key Sources for Reference Data

| Parameters | References |
|---|--|
| Parasitic energy consumption for biogas generation and the overall biogas conversion efficiency | (Zglobisz, et al., 2010), (Borjesson and Ahlgren, 2012), (Poschl, et al., 2010), (Balussou, et al., 2012), (Finning CAT, n.d.), (Wipro, 2014), (Nielsen and Oleskowicz-Popiel, 2008), (Zamalloa, et al., 2011), (Dave et al., 2013), (Murphy and Power, 2008). |
| Parasitic energy consumed for gasification, and the overall efficiency of gasification | (Mozaffarian and Zwart, 2003) (Nystrom and Bjokombi, 2007) (Gallagher and Murphy, 2013) (Tuna, 2008), (Progressive Energy & CNG Services, 2010), (Mozaffarian and Zwart, 2003), (Gallagher and Murphy, n.d.), (Melin, 2011). |
| Investment and operating costs for AD biogas generation | (Borjesson and Ahlgren, 2012), (Zglobisz et al., 2010), (Enagri, 2011), (Foreest, 2012), (Dave et al., 2013), (Balussou, et al., 2012). |
| Investment and operating costs for gasification | (Gallagher and Murphy, 2013), (Melin, 2011), (Progressive Energy & CNG Services, 2010), (Clarke et al., 2009), (Koornneef et al., 2013), (Clarke et al., 2009) (NREL, n.d.) (DTI, 2003). |
| Base case electricity and heat supply GHG impact | (Whiting and Azapagic, 2014), (Evangelisti, et al., 2013) |
| GHG linked to the CCGT | (Abadie and Charmorro, 2008), (Fuchsz and Kohlhe, 2015), (Evangelisti, et al., 2013). |

APPENDIX B: EQUATIONS FOR ENERGY FLOW BALANCES AND CONSTRAINTS

The equations presented here should be understood together with Figures 1, 2 and 3, and notations therein, particularly for the meaning of the variables including f_i , a_i , b_i and y_i .

Energy Balance for the Household Boiler

The household heat demand data obtained from the UK Energy Research Council (UKERC, 2011), d_{hb} , is provided as gas consumption over time. However, to convert this to the actual heat demand over time, d_h , an efficiency of the conventional boiler, E_{st} , was assumed:

$$d_h = E_{st} \times d_{hb} \quad (\text{i.})$$

Energy Balance for the Energy Supply Network at the Household Level

$$y_3 - y_7 - y_{17} = 0 \quad (\text{ii.})$$

$$y_7 - (E_{st} \times y_3) = 0 \quad (\text{iii.})$$

$$y_8 = B_e \times d_h \quad (\text{iv.})$$

$$b_{10} + y_7 - y_9 - y_{18} = 0 \quad (\text{v.})$$

$$y_9 = E_{bt} \times (y_7 + b_{10}) \quad (\text{vi.})$$

$$y_9 - d_h - y_{19} = 0 \quad (\text{vii.})$$

$$d_h = E_{ht} \times y_9 \quad (\text{viii.})$$

$$y_1 - d_e - y_8 = 0 \quad (\text{ix.})$$

where,

Be Efficiency for electricity supplied to the boiler based on the amount of heat it produces

d_e Electricity demand

E_{bt} Efficiency of heat storage

E_{ht} Efficiency of radiator

Energy Balance for Biomethane Feedstock Supply

$$z_1 - (f_1 + f_7) - b_{L1} = 0 \quad (\text{x.})$$

$$z_2 - (f_2 + f_8 + f_{13}) - b_{L2} = 0 \quad (\text{xi.})$$

$$z_3 - (f_3 + f_9) - b_{L3} = 0 \quad (\text{xii.})$$

$$z_4 - (f_4 + f_{10} + f_{14}) - b_{L4} = 0 \quad (\text{xiii.})$$

$$z_5 - (f_5 + f_{11} + f_{15}) - b_{L5} = 0 \quad (\text{xiv.})$$

$$z_6 - (f_6 + f_{12} + f_{16}) - b_{L6} = 0 \quad (\text{xv.})$$

$$z_7 - f_{17} - b_{L7} = 0 \quad (\text{xvi.})$$

$$z_8 - f_{18} - b_{L12} = 0 \quad (\text{xvii.})$$

$$f_{19} - f_{17} - f_{18} - b_{L6} - b_{L7} = 0 \quad (\text{xviii.})$$

where

z_i Total primary energy from each feedstock for biogas/bio-SNG supplied, with i referring to the energy flow being considered

Energy Balance for Biomethane Generation

Following the flow structures presented in Figures 1 and 2 and the flow numbers thereof, the following energy balance equations need to be satisfied:

$$b_3 - f_{13} - f_{14} - f_{15} - f_{16} = 0 \quad (\text{xix.})$$

$$b_1 - f_1 - f_2 - f_3 - f_4 - f_5 - f_6 = 0 \quad (\text{xx.})$$

$$b_2 - f_7 - f_8 - f_9 - f_{10} - f_{11} - f_{12} = 0 \quad (\text{xxi.})$$

$$b_4 + b_5 + b_6 - f_{17} - f_{18} = 0 \quad (\text{xxii.})$$

$$b_1 + b_6 - b_9 - b_{11} - b_{L8} = 0 \quad (\text{xxiii.})$$

Energy Flow Constraints for Biomethane Generation, Processing and Use

$$\begin{aligned}b_{L1} - (w_5 \times z_1) &= 0 & (\text{xxiv.}) \\b_{L2} - (w_5 \times z_2) &= 0 & (\text{xxv.}) \\b_{L3} - (w_5 \times z_3) &= 0 & (\text{xxvi.}) \\b_{L4} - (w_5 \times z_4) &= 0 & (\text{xxvii.}) \\b_{L5} - (w_5 \times z_5) &= 0 & (\text{xxviii.}) \\f_1 + f_7 &= (P_1 \times S_1) & (\text{xxix.}) \\f_2 + f_8 + f_{13} &= (P_2 \times S_2) & (\text{xxx.}) \\f_3 + f_9 &= (P_3 \times S_3) & (\text{xxxi.}) \\f_4 + f_{10} + f_{14} &= (P_4 \times S_4) & (\text{xxxii.}) \\f_5 + f_{11} + f_{15} &= (P_5 \times S_5) & (\text{xxxiii.}) \\f_6 + f_{12} + f_{16} + f_{17} &= (P_9 \times S_9) & (\text{xxxiv.}) \\f_{18} &= (P_8 \times S_8) & (\text{xxxv.}) \\b_9 - [E_{ch} \times (b_1 + b_6)] &= 0 & (\text{xxxvi.}) \\b_{11} - [E_{ce} \times (b_1 + b_6)] &= 0 & (\text{xxxvii.}) \\b_{L8} - [(1 - E_{ct}) \times (b_1 + b_6)] &= 0 & (\text{xxxviii.}) \\E_{ct} - E_{ce} - E_{ch} &= 0 & (\text{xxxix.}) \\b_{L11} - (w_1 \times b_9) &= 0 & (\text{xl.}) \\b_{14} - (w_2 \times b_{11}) &= 0 & (\text{xli.}) \\b_{L9} - (w_3 \times b_2) &= 0 & (\text{xlii.}) \\b_{L10} - [w_4 \times (b_3 + b_4)] &= 0 & (\text{xliii.}) \\a_{Le} - (E_e \times a_2) &= 0 & (\text{xliv.}) \\a_{Lg} - (E_g \times a_2) &= 0 & (\text{xlv.}) \\a_1 - (E_{pp} \times a_7) &= 0 & (\text{xlvi.}) \\a_{L3} - [(1 - E_{ed}) \times (a_1 + b_{12})] &= 0 & (\text{xlvii.})\end{aligned}$$

where

E_{ce} Electrical efficiency of the centralised CHP plant

| | |
|----------|--|
| E_{ch} | Thermal efficiency of the centralised CHP plant |
| E_{ct} | Total efficiency of the centralised CHP plant |
| E_e | Efficiency of gas distribution, in electricity consumed per kWh energy distributed |
| E_{ed} | Efficiency of the Electricity Distribution System |
| E_g | Efficiency of gas distribution, in gas consumed per kWh energy distributed |
| E_{pp} | Central power plant (CCGT) efficiency |
| P_i | Biomethane potential for each of the given bio-energy feedstock |
| S_i | Total units of feedstock i, supplied for the particular system being considered |
| w_1 | Process efficiency for the centralised CHP heat supply |
| w_2 | Percentage amount of electricity consumed by the centralised CHP plant. |
| w_3 | Process efficiency of the Biogas Upgrade Plant |
| w_4 | Process efficiency of the conventional natural gas processing plant |
| w_5 | Process efficiency of biomass feedstock conversion |

Energy Balance for Biomethane Processing and Use

$$b_9 - b_{L11} - b_{10} = 0 \quad (\text{xlviii.})$$

$$b_{11} - b_{12} - b_{14} = 0 \quad (\text{xlix.})$$

$$b_2 - b_8 - b_{L9} = 0 \quad (\text{l.})$$

$$b_3 + b_4 - b_7 - b_{L10} = 0 \quad (\text{li.})$$

$$a_2 - b_8 - b_7 - b_5 - a_8 = 0 \quad (\text{lii.})$$

$$a_2 - a_4 - a_7 - a_{lg} = 0 \quad (\text{liii.})$$

$$a_7 - a_1 - a_{l2} = 0 \quad (\text{liv.})$$

$$a_1 + b_{12} - a_3 - a_{l3} - a_{le} = 0 \quad (\text{lv.})$$

$$a_{lc} + a_{l2} - a_{l3} - a_{le} - a_{lg} = 0 \quad (\text{lvi.})$$

$$a_{l1} - a_{le} - a_{lg} = 0 \quad (\text{lvii.})$$

$$a_3 - y_1 = 0 \quad (\text{lviii.})$$

$$a_4 - y_3 = 0 \quad (\text{lix.})$$

Constraint for Biogas Upgrading with Existing Gas Processing Plant

For the option of upgrading biogas within a natural gas processing plant, a constraint is introduced to reflect the realistic scenario that not more than a threshold fraction (α) of the gas from the natural gas processing plant can be made up of biogas (b_3 and b_4) compared to the natural gas (a_8):

$$b_3 + b_4 \leq \alpha \times (b_3 + b_4 + a_8) \quad (\text{lx.})$$

Beyond this level, the calorific value for entry to the gas grid can no longer be met according to the standards. In the case of the UK National Transmission Specification (NTS) regulatory requirements, this fraction was chosen in this work as 0.5.

Constraints Reflecting Feedstock Availability

Furthermore, the maximum biomethane-to-natural gas displacement percentage by a specific type of feedstock is limited by the feedstock's availability in the country of interest. In this work, this constraint is introduced by imposing a maximum percentage of total gas supply through the gas grid that can be provided by biomethane from each specific type of biomass:

$$f_1 + f_7 \leq (a_2 \times f_{1m}) \quad (\text{lxi.})$$

$$f_2 + f_8 + f_{13} \leq (a_2 \times f_{2m}) \quad (\text{lxii.})$$

$$f_3 + f_9 \leq (a_2 \times f_{3m}) \quad (\text{lxiii.})$$

$$f_4 + f_{10} + f_{14} \leq (a_2 \times f_{4m}) \quad (\text{lxiv.})$$

$$f_5 + f_{11} + f_{15} \leq (a_2 \times f_{5m}) \quad (\text{lxv.})$$

$$f_6 + f_{12} + f_{16} + f_{17} \leq (a_2 \times f_{9m}) \quad (\text{lxvi.})$$

$$f_{18} \leq (a_2 \times f_{8m}) \quad (\text{lxvii.})$$

where

| | |
|----------|--|
| f_{1m} | Maximum percentage of biomethane in the natural gas grid obtained from farm waste feedstock |
| f_{2m} | Maximum percentage of biomethane in the natural gas grid obtained from MSW / C&IW feedstock |
| f_{3m} | Maximum percentage of biomethane in the natural gas grid obtained from sewage feedstock |
| f_{4m} | Maximum percentage of biomethane in the natural gas grid obtained from Macroalgae Feedstock |
| f_{5m} | Maximum percentage of biomethane in the natural gas grid obtained from microalgae feedstock |
| f_{8m} | Maximum percentage of biomethane in the natural gas grid obtained from energy crops feedstock for gasification |
| f_{9m} | Maximum percentage of biomethane in the natural gas grid obtained from energy crops feedstock for AD |

Values of the above parameters are presented in Table A3 in Appendix A.

APPENDIX C: MODELLING OF COST STREAMS

Costs Streams for the Various Biomethane Units

There are a number of costs, including capital costs, tax liabilities, and feedstock costs, applied to each type of the biomethane processing units, which is represented by i in the following equations which may refer to one of the following types of units:

- c centralised CHP plant
- u conventional biogas upgrade unit
- ng natural gas processing plant
- g gasification plant
- a AD plant

Capital Cost for Each Biomethane Processing Unit

The capital cost for each biomethane generation unit, C_i , is:

$$C_i = P c_i \times \max(z_i) \quad (\text{lxviii.})$$

where, for processing options $i = c, u, ng, g, a$:

$P c_i$ Unit plant capital cost

z_i Production scale in terms of energy delivered, thus with $\max(z_i)$ representing the maximum energy delivered (capacity) at any time throughout the year

C_i Capital investment cost for the plant, which is assumed to be expensed in Year 1.

Cost of Feedstock

The total annual cost of feedstock to processing unit type i , $C f_i$, is calculated by:

$$C f_i = \sum_{s=1}^5 \sum_{d=1}^{nd(s)} \sum_{t=1}^{24} [C f x_{i,t} \times S_i(t, s, d)] \quad (\text{lxix.})$$

where

i AD (a) or gasification plant (g), which directly consumes biomass

Cf_{i} Total annual cost of feedstock for unit type i

$Cf_{x,i}$ Unit feedstock cost to unit type i

d Day in season s, $d = 1$ to $nd(s)$

$nd(s)$ number of days in season s

S_i Amount of feedstock supplied to unit type i

s Season in a year, $s = 1$ to 5

t Hour in a day, $t = 1$ to 24

Operating Costs

The total annual operating cost of each unit type i, To_i , is defined by:

$$To_i = \sum_{s=1}^5 \sum_{d=1}^{nd(s)} \sum_{t=1}^{24} [Tox_i \times C_i(t, s, d)] \quad (lxx.)$$

where,

Tox_i Unit percentage for operating cost as a factor the capital cost for unit type i,

To_i Total annual operating costs of unit type i,

$i = c, u, ng, g, a.$

Tax Liabilities and Depreciation

The annual depreciation, Rd_i for each unit type is as calculated as follows: The final amounts left to claim at the end of 20 years is spread over the plant years equally and distributed, irrespective of whether the sum is less or greater than the tax liability for that year (Masons, 2016).

$$Rd_i - (0.05 \times C_i) = 0 \quad (lxxii.)$$

The actual annual tax liability for each unit type, T_i , is defined by:

$$T_i = Tx \times \sum_{s=1}^5 \sum_{d=1}^{nd(s)} \sum_{t=1}^{24} [(Rs_i(t, s, d) - Rd_i(t, s, d) - To_i(t, s, d) - Cf_i(t, s, d))] \quad (lxxii.)$$

where,

Rs_i Revenue from the sale of each energy product for the unit being considered,

To_i Total variable and fixed operating cost based on either the energy processed,

T_x Corporate tax rate.

APPENDIX D: MODELLING OF REVENUE STREAMS

Revenue from Sale of Energy Product

The revenues for different process unit types are modelled by:

$$Rs_c - (m_{12} \times b_{12}) - (m_{10} \times b_{10}) = 0 \quad (\text{lxxiii.})$$

$$Rs_u - (m_8 \times b_8) = 0 \quad (\text{lxxiv.})$$

$$Rs_n - (m_7 \times b_7) = 0 \quad (\text{lxxv.})$$

$$Rs_g - (m_4 \times b_4) - (m_5 \times b_5) - (m_6 \times b_6) = 0 \quad (\text{lxxvi.})$$

$$Rs_a - (m_1 \times b_1) - (m_2 \times b_2) - (m_3 \times b_3) = 0 \quad (\text{lxxvii.})$$

where,

Rs_c Total revenue from the sale of product from centralised CHP,

Rs_u Total revenue from the sale of product from biogas upgrade,

Rs_n Total revenue from the sale of energy product from the natural gas processing plant based biogas upgrade,

Rs_g Total revenue from the sale of energy product from gasification,

Rs_a Total revenue from the sale of energy product from AD,

m_i Unit price of each energy product sold, set to zero in this case for AD biogas generation and gasification.

Enhanced Capital Allowance

The Enhanced Capital Allowance, Rec_i , is meant to be a tax relief to be taken in the fifth year of operation of the plant (DECC, 2016), and will therefore be deducted from the tax liability, T_i , in that year. Constraints were applied to ensure that the Enhanced Capital Allowance was always less than the capital investment or less than the tax liability for the fifth year. These are to ensure that in the fifth year, ECA is not claimed to a level that is in excess of the capital that was invested in the first year, and that the ECA remains a tax break and therefore has the annual tax liability in the fifth year as its ceiling. The present value of this fifth year revenue or tax relief, $Recv_i$, was then calculated as:

$$Rec_i = \min (T_i, C_i) \quad (\text{lxxviii.})$$

$$(\text{lxxix.})$$

$$Recv_i - \left[\frac{Rec_i}{(1 + r_d)^5} \right] = 0 \quad (\text{lxxx.})$$

T_i Tax liability of plant type i , $i = c, u, ng, g$, and a , as introduced earlier,

C_i Capital invested of plant type I , $i = c, u, ng, g$, and a , as introduced earlier,

R_{ec} Value of the Enhanced Capital Allowance obtainable in Year 5,

$R_{ecv,i}$ Present value of the Enhanced Capital Allowance obtainable in Year 5.

Feed-in-Tariff

The Feed-in Tariff (FiT), Rf_c , provides for a guaranteed price to be paid by the UK government for electricity generated from renewable energy (ofgem, 2016). It consists of a generation tariff, Rf_1 , and an export tariff, Rf_2 . As a guaranteed price is given to electricity producers of less than 5 MW (for biogas), this study assumes a 1 MW capacity plant, and so an 8.96 p/kWh FIT generation tariff will be assumed. Although from 2014 in the UK, the tariff rates will decrease by 5% year on year, accelerating or decelerating based on the extent of technology deployment (ofgem, 2016), this is not taken into consideration in this study.

$$Rf_c = \sum_{s=1}^5 \sum_{d=1}^{nd(s)} \sum_{t=1}^{24} [Rf_1 \times b_{11}(t, s, d)] + [Rf_2 \times b_{12}(t, s, d)] \quad (\text{lxxxi.})$$

Renewable Heat Incentive

All biomethane plants built after 15th July 2009 in the UK are eligible for the Renewable Heat Incentive (RHI) of 7.1 p/kWh for biogas combustion of up to 200 kW and 7.1 p/kWh for biomethane injected into the grid (Environment Agency, 2016).

$$Rh_c = \sum_{s=1}^5 \sum_{d=1}^{nd(s)} \sum_{t=1}^{24} [Rh \times b_{10}(t, s, d)] \quad (\text{lxxxii.})$$

$$Rh_u = \sum_{s=1}^5 \sum_{d=1}^{nd(s)} \sum_{t=1}^{24} [Rh \times b_8(t, s, d)] \quad (\text{lxxxiii.})$$

$$Rh_{ng} = \sum_{s=1}^5 \sum_{d=1}^{nd(s)} \sum_{t=1}^{24} [Rh \times b_7(t, s, d)] \quad (\text{lxxxiv.})$$

$$Rh_g = \sum_{s=1}^5 \sum_{d=1}^{nd(s)} \sum_{t=1}^{24} [Rh \times b_5(t, s, d)] \quad (\text{lxxxv.})$$

where Rh_c , Rh_u , Rh_{ng} and Rh_g are the RHI applicable to centralised CHP, conventional biogas upgrading, the natural gas processing plant based biogas upgrading, and gasification unit, respectively, Rh is the unit rate for the RHI.

Climate Change Levy Exemption Certificate

Where biomethane is used for generating electricity in the UK, the Levy Exemption Certificate will apply, referring to supplied energy commodity rather than feed commodity. The revenue rate for 2013 upwards at 0.182 p/kWh for fuel input and 0.524 p/kWh for electricity output is applied as an average figure for the modelled period (ofgem, 2016).

$$Rc_c = \sum_{s=1}^5 \sum_{d=1}^{nd(s)} \sum_{t=1}^{24} [Rc \times (b_1(t, s, d) + b_6(t, s, d))] \quad (\text{lxxxvi.})$$

where Rc_c is the climate change levy exemption applicable to centralised CHP, and Rc is the unit rate for the exemption.

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