Future challenges to asset investment in the UK water industry: the wastewater asset investment risk mitigation offered by minimising principal operating cost risks

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ABSTRACT

This paper defines challenges currently facing the water industry globally that will affect water industry asset investment and development now and in the near future. Those challenges include energy price volatility, climate change regulation, asset capital costs and strategic resource considerations. This paper presents potential answers to these challenges in the context of the UK water industry and described a methodology developed to assess them and provide accurate cost-benefit analysis. A best practice approach which allows sustainable investment to offer water utilities operational efficiency benefits, including cost benefits, is described and the critical elements of the best practice developed by the author identified.

Key words | carbon reduction cost benefits, sustainable asset development

ABBREVIATIONS

BNR biological nutrient removal
BOD biological oxygen demand
CRC Carbon Reduction Commitment
DEFRA Department for Food, Environment and Rural Affairs
MAD mesophilic anaerobic digestion
NPV Net Present Value
PE person equivalents
PMF plastic media filters
ROC Renewables Obligation Certificates
SBR sequencing batch reactor
VFA volatile fatty acids
VSS volatile solids

INTRODUCTION

The global water industry is facing an unprecedented coincidence of challenges to its operating costs and the value of its asset base. These challenges include climate change and its mitigation, requiring water companies to minimise their carbon footprint; increasing energy costs leading to increased operating costs, thus undermining the profitability of water companies; and recently, increased cost of capital and decreased capital availability.

These factors combine against a background of continuing increase in environmental regulation, requiring further investment in and development of, the capacity and capability of the water company asset base. In the UK, climate change mitigation is now being legislated and regulated in a manner that affects its water industry, and the UK, therefore, provides an example of the combined challenges that the water industry in other countries may face in the near future.

The searching question being asked of the UK water industry is: “How can the water industry reduce its carbon footprint in line with Government requirements and increase its cost efficiency, while being obliged to increase asset base capacity and capability by population increases and new regulation?” Optimal carbon management has to be placed in this context: as an issue to be addressed by...
sustainable asset investment and development whose mitigation also offers cost benefits to water companies and their shareholders and stakeholders while integrating the water industry in a national renewable ‘fabric’.

The problem addressed by this paper can be defined as the provision of the best whole life cost outcome for future asset development and investment in the water industry that provides mitigation of the following risk factors:

- Power cost inflation
- Climate change regulation and carbon footprint
- Capital cost
- Strategic resources and resource recovery.

The risk to operating costs posed by power cost inflation is high. In the UK, it has been reported that the UK water company, NWG, suffered a 12% drop in profit for the 6 months up to September 2008, despite a 4.2% increase in revenue (Financial Times 28 November 2008). This was attributed mainly to power cost inflation of over 50% over the previous 6 months by NWG, a level of energy price increase confirmed by the Department of Energy and Climate Change (DECC) report of December 2008.

Power cost inflation for UK industrial power users was 11% as an annual average for 2004–2007 (Eurostat 2007). DECC (DECC 2008) reported an annual price increase interim figure of 22.8% for the third quarter between 2007 and 2008.

There is now a substantial body of energy industry opinion that we are either now at peak oil or that it is, in practical terms, imminent. The most recent (2009) International Energy Agency report, anticipates global peak oil production by 2020, with severe supply-growth constraint starting in 2010 and severe inflationary pressure on price before peak production. For the UK, fossil fuels still provide the large majority of national electrical power generating capacity with 38% provided by coal, 34% from natural gas and 6% oil-fired (BERR 2007). Energy costs typically contribute 10% of UK water company total operating costs, with energy power cost inflation threatening to increase that proportion (Global Water Intelligence 2008). While some energy prices may have recently reduced due to the recent global recession, the risk for the near future and medium term is a return to increasing power cost inflation (Sharm & Constable 2008) (Figure 1).

Any fossil fuel energy crisis in terms of supply and energy cost, is likely to be compounded by climate change regulation, as governments seek to reduce carbon dioxide output through legislation. The UK provides an example of government review of climate change issues leading to the development of regulation affecting the water industry via legislation. Her Majesty’s Government commissioned the Stern Review, which reported in 2006 that successful climate policies required three elements: carbon pricing, elimination of barriers to behavioural change and an integrated technology policy (Stern 2006). This led to legislation to extend carbon regulation beyond the large carbon emitters covered by the EU Emission Trading Scheme: the Carbon Reduction Commitment (CRC).

The CRC comes into force in 2010, coincidentally at the start of the latest UK water industry Asset Management Plan implementation period. It affects power consumers on the scale of the water industry and requires them to purchase carbon allowances at £12/tonne carbon dioxide in its initial phase (2010–2012). Energy consumers who fail to comply with the CRC are liable to penalties levied at £25/tonne in the first phase. In the second phase of the CRC, from 2013, the total carbon allowance will be capped and carbon generators will have to purchase allowances by

![Figure 1](https://iwaponline.com/jwcc/article-pdf/1/1/17/375158/17.pdf)
competitive auction. Penalties increase to £75/tonne carbon dioxide in the second phase (Sarwar 2008).

The UK water industry carbon footprint is associated mainly (some 70%) with ‘operational carbon’ arising from national grid power use, as the CRC recognises by focusing on the use of national grid power. The UK water industry is privatised, but, in recognition of the problems inherent in achieving competition between service providers with fixed capital assets in water and wastewater infrastructure, the industry has an economic regulator, OFWAT, as well as water supply quality and sewage discharge quality regulators (the Drinking Water Inspectorate and the Environment Agency, respectively). For the latest UK water industry Asset Management Plans, the economic regulator has introduced new criteria relating to sustainability and climate change mitigation. In addition, the economic regulator’s expectation is that opportunities for renewable energy generation that are naturally synergistic with water company operations will be exploited (Burgess 2008).

Asset investment planning is now required to provide ‘demonstrably sustainable low carbon solutions’ and cost-benefit analysis is meant to include the UK shadow price of carbon assessment (Burgess 2008; Whipps 2008). The Shadow Price of Carbon is based on a fixed penalty sum for the amount of carbon emissions associated with a project or process, adjusted for inflation, being applied to investment projects (DEFRA 2007). That penalty is added to project whole life cost and the outcome checked against whether the Net Present Value (NPV) difference is more than 5% as a result of the difference is low and high carbon emissions. The Shadow Price of Carbon method predates recent trends in power cost inflation and the CRC.

Capital cost is a particularly significant issue for the water industry. Its capital assets are typically large fixed installations with a long asset life, varying from 15 to 30 years for mechanical and electrical assets and 30–60 years (or more) for civil assets. For water companies with multiple water and wastewater treatment assets within a particular geographic zone, as in the UK, this creates a substantial asset base with a high write-off value. It is possible for the populations served and regulations for water and treated sewage quality to change, within the life of the assets that comprise a treatment facility. As a result, asset development is often a mix of refurbishment and extension of existing facilities combined with new green-field site developments. For this type of water company, not confined to serving a single municipality, the asset base may also include centralised facilities for dealing with treatment process wastes, such as sewage sludge in particular.

The drivers for capital investment are typically new regulations and water or wastewater quality requirements and/or increases in capacity, or capital maintenance—the necessary replacement of equipment and systems. In the UK, where there is a commercial regulator, investment planning is carried out on a 5-year Asset Management Plan basis, with water companies submitting their investment plans to the commercial regulator for review. Whatever the planning cycle, water industry assets require substantial capital investment and projects typically seek to maximise capital value for money. Challenges for investment planners include maximising budgets but also striking a balance on whole life cost. Generations of regulatory change successively increase the capability demanded of water and wastewater treatment facilities while increases in population served demand increases in capacity. The two combined increase pressure on operating costs, which is now compounded by critical factors such as power cost inflation, carbon regulation and even strategic resource recovery.

In the UK, the Government Department for Food, Environment and Rural Affairs (DEFRA) has responsibility for food, agriculture and the environment. There are historic links between DEFRA and the UK water industry due to the primary end disposal route for sewage sludge being the agricultural landbank since the closure of the sea disposal route. DEFRA are now concerned about another aspect of sewage sludge processing—recycling phosphorus. Global phosphorus reserves are currently projected to be exhausted by 2070 on some estimates. However, no analysis of peak phosphorus production was attempted until 2007, when Dery and Anderson applied a Hubbert linearisation to the analysis of regional and global phosphorus production data (Dery & Anderson 2007). Their conclusion was that global phosphorus peak production occurred in 1989. More recently, this has been revised and is expected to occur in 2034 (Cordell et al. 2009). Phosphorus is a critical biological element and essential for food production. As phosphate, 80% of global use is for agricultural fertilisers, which...
recently rose by 300% in price due to feedstock shortages. *The Times* (23 June 2008) reported a 700% increase in phosphate rock cost over the previous 14 months and that China had imposed a tariff on its own rock phosphorus exports, to begin to manage its reserves. Phosphorus and nitrogen can be recovered during sewage sludge treatment (Evans 2009) and phosphorus, in particular, could become a strategic resource that governments move to regulate in the not too distant future.

The challenges to water industry investment planners which are global rather than regional include increasing demands for delivery of improvements in treatment facility capacity and capability for the best whole life cost. Labour costs are still the leading single operating cost element, despite modern water and wastewater treatment facilities incorporating a significant degree of automation. That places a finite constraint on any potential operating savings that could be made from labour costs. However, there is upward pressure on what is presently the second highest operating cost, energy. Obtaining the best whole life cost solution now requires careful consideration of the balance of capital and overall operating costs for a whole life cost measure such as NPV, over periods of 30 years or more.

**Method development**

To successfully address the challenges to asset investment and operational efficiency described above, water industry asset developers need project solutions that can deliver minimal operating cost for value for money capital investment combined with minimal carbon footprint and consistent with a capability for strategic resource recovery.

This is a demanding combination of objectives, but they are achievable. The issues of operating cost and carbon footprint are interlinked, because the principal risk to operating costs for the short and medium term is energy cost volatility and power cost inflation. As 70% of water industry operational carbon footprint typically results from electrical power consumption, energy efficiency improvements offer a substantial solution (Figure 2).

In this context, energy efficiency improvements are offered by both reduction in power demand (the traditional definition of energy efficiency) and the exploitation of on-site opportunities for renewable energy generation.

![Figure 2](https://iwaponline.com/jwcc/article-pdf/1/1/17/375158/17.pdf)

**Figure 2** Obtaining energy and legislated carbon neutrality for UK water industry treatment assets.

Traditional energy efficiency measures alone reduce demand; however, they cannot reduce demand to zero (Figure 1). As a result, any potential there is for water and wastewater treatment assets to become energy neutral (and therefore carbon neutral in the UK in CRC terms), depends on the opportunities they offer to generate renewable energy on-site. The challenge becomes greater when value for money for capital investment and more importantly, for whole life cost, is sought. Not all the assets held and operated by water companies offer the same opportunities for renewable energy generation. On a thermodynamic basis, those options are strongly influenced by the number of viable options in whole life cost terms for energy recovery from either the processes hosted by the assets or the materials handled by them, or associated environmental opportunities (e.g. wind power, solar power, etc).

Water and sewage treatment involves substantial power demand from carriage, i.e. substantial energy demand from pumping. For wastewater treatment that mass transfer also involves large masses of potentially polluting waste material, both suspended and soluble. That amount of mass offers good theoretical potential for energy recovery if some reasonable fraction of the mass can be converted to energy at a reasonable efficiency. Conversely, raw water for potable water production is selected precisely because it bears a minimal ‘polluting’ load. That is the principal difference which confines renewable energy recovery for water treatment assets to topographic opportunities, wind, solar or groundwater heat recovery or recovery of some of the energy put into the system. By contrast, wastewater treatment receives a substantial material load which has a
high organic fraction and during treatment generates an organic ‘waste’. These materials can be viewed as redundant resources and resource remnants that provide opportunities for renewable energy generation and strategic resource recovery—in an asset base already provided for an original purpose of pollution control.

From basic thermodynamic considerations of mass transport, energy demand and potential for energy recovery, the best opportunities for reducing power demand and concomitant carbon footprint (in the UK to at least CRC carbon neutrality) to the point of energy and operating carbon neutrality are offered at large wastewater treatment sites.

These particular assets, as a consequence of these inherent advantages, also offer better whole life cost outcomes and return on capital investment. This paper will focus on energy and resource recovery opportunities at large sewage treatment works (Figure 3).

It must be emphasised that the most efficient energy efficiency strategies are those that systematically reduce energy demand across the entire asset base and arise from energy use benchmarking of the asset base to define its performance and identify where the worst energy efficiency occurs. In that regard, improving the energy efficiency of water supply, treatment and distribution is essential to planning and promulgating a successful energy efficiency programme. For a water supply only operation, it is the only option.

However this study shows what might be expected: that large-scale sewage treatment is the ‘low-hanging fruit’ of the asset base in terms of energy efficiency and the potential for energy generation, in particular in terms of attaining energy neutrality and even energy production from the range of assets available within the typical water industry asset base.

Our study initially considered green-field projects, then moved on to include asset refurbishment projects. Large-scale asset refurbishment projects are common in the water industry because assets have a long life and during the asset life, plant capacity is often challenged by population increases and asset capability challenged by changes in legislation and, consequently, regulation. The long asset life and high capital value of existing assets also contributes to another investment factor: high asset write-off values. These drive the water industry to maximise the life of its existing assets wherever possible, to maximise its capital value and return on capital investment. This approach has now gained further merit as it tends to minimise the level of asset replacement short of its full potential asset life—which in turn minimises embodied carbon emissions.

In providing a thermodynamically based approach to strategic water company asset development it was necessary for MWH to build model assets on the basis of a new design paradigm:

- To maximise treatment efficiency per kilowatt of energy used;
- to minimise green-house gas emissions; principally CO₂ but also non-CO₂ emissions;
- to maximise the beneficial use of sludge and other resources; and
- to maximise opportunities for renewable energy generation, firstly for on-site use and secondly for export.

This approach led to the development of a combined mass and energy balance based on a process flow diagram. The mass balance incorporates the full range of wastewater quality determinants and assumes the works are operating at a steady state. In other words, the mass balance approach provides a state variable \( x_i \) \((i = 1, \ldots, n)\) for each determinant of interest—in this case sewage pollutants monitored in the overall treatment plant influent and discharge. The state equations of a mass balance describe a flow and material load thus:

\[
x'_i = r_i - q_i + p_i
\]
where $p_i$ is inflow (rate), $q_i$ is outflow and $r_i$ is the process removal or transformation rate (process efficiency). The mass balance process stages include those described in Figure 4, with the principal elements being primary sedimentation, biological treatment, and sludge processing and treatment, but also include all significant recycles, such as return activated sludge, and return flows to treatment such as sludge liquor returns, as well as additional streams such as chemical dosing.

For existing works, where performance data is typically readily available, setting the mass balance to an annual average day provides a robust steady state model that incorporates both flow and load variation and seasonality. Once the mass balance is set, each process treatment stage then has an energy balance set for it. This incorporates typical (annual average daily) power demand from the equipment associated with the treatment stage which also incorporates a heat balance for significant heat demanding processes such as mesophilic anaerobic digestion (MAD), sludge drying and digested sludge gasification. The heat balances are all based on heat transfer considerations:

$$Q = mc\delta T$$

(where $Q$ is heat flux, $c$ is heat capacity, $m$ is mass and $\delta T$ is temperature difference),

which are particular to the treatment process the energy balance is provided for. The energy demand for each treatment stage is then summed and the total is then available for comparison to metered or power invoice data as described below.

The annual average day can be compared to and calibrated against:

Annualised power cost/365 days = Annual daily average

(as municipal wastewater treatment plants typically run continuously through a year).

Provided the mass and energy balances are comprehensive enough and the information used sufficiently accurate, good agreement can be achieved. For a 160,000 PE works and comprehensive mass and energy balance, this method was accurate to within 1% error for power demand.

This approach provides several advantages in that:

(i) The tool for assessing the energy efficiency of the asset can be built during an energy audit of any existing asset or based on design intent.

(ii) The method works with standard design outputs and will therefore fit into current asset design procedures.

(iii) The energy balance can be calibrated against annual plant total power demand for asset upgrading projects, using power company invoicing records, if the existing sewage works lacks extensive power demand metering and sub-metering.

(iv) The use of an annual average day as the basis for the combined mass and energy balance takes account of seasonality and flow and load variation.

The existing plant or initial design intent provides the information that allows the asset operator or the asset designer to set up a benchmark combined mass and energy balance. For any existing asset, an energy audit and plant

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Figure 4 | Mass balance process elements. CHP = combined heat and power.
performance data are used to construct the mass and energy balance, calibrated against plant data. For a proposed asset, the design intent and provisional equipment specification allows the initial combined mass and energy balance to be set. Thereafter, a combined mass and energy balance allows a plant manager or treatment asset designer to consider different operational management regimes and asset intervention options. The combined mass and energy balance is set to the critical process parameters for those options, and the scenario outputs then compared to the initial (benchmark) combined mass and energy balance.

If the combined mass and energy balance outputs are used for cost-benefit analysis, the best cost outcome in terms of whole life cost (net present value) can be determined along with the associated capital and operational costs.

If $IC_k$ is the investment cost of a unit $k$ and $OC_k$ the operating cost, the NPV of the sewage plant investment can be determined by:

$$\text{NPV} = \sum_{k=1}^{N} IC_k + \left( \frac{1 - (1 + i)^{-n}}{i} \right) \sum_{k=1}^{N} OC_k$$

where $i = \text{interest rate}$ and $N = \text{number of units}$ (Gillot et al. 1999)

Based on a thermodynamic approach to the typical water industry flow sheets for large carbonaceous and nutrient-removing wastewater treatment assets, the following processes were identified as key factors in maximising energy and material resource recovery in a UK context:

- maximising solids removal under gravity in existing primary treatment by chemical enhancement;
- minimising downstream pollution load and energy demand to secondary biological treatment while at the same time maximising primary sludge load and calorific/resource value downstream sludge processing including anaerobic digestion;
- optimising anaerobic digestion to further boost biogas rate of production through enhanced digestion;
- resource recovery from recycling P to agricultural at minimum, as a cost benefit to the operator;
- recovery of further energy post-digestion through the lowest carbon footprint combustion process that can also produce a valuable by-product (biochar): sludge gasification which also attracts energy incentives (two Renewables Obligation Certificates (ROCs)/MWhr if exported in the UK).

Minimising whole life cost is a key objective of minimising the risk from power cost inflation, which directly affects operating costs. However, water industry assets typically have a quite high residual capital cost. This results in whole life cost being strongly affected by capital cost, which means that value for money capital investment, in meeting the challenge of power cost inflation and carbon footprint, needs to provide solutions that minimise capital cost.

Selecting process equipment and/or technologies that can extend both the capability and capacity of existing assets, means that any existing assets can be reused as far as possible, reducing capital cost and embodied carbon. This particular approach is of no benefit to green-field site developments, but given that water industry asset development often includes refurbishment and redevelopment projects, it does offer these projects an approach that combines asset continuity with the opportunity for minimising both capital cost and embodied carbon.

Water company assets have a substantial residual asset value and maximising returns on capital investment typically precludes premature asset write-off. However, lifetimes of 30–60 years for some assets offer more than sufficient time for regulatory and cost drivers for asset investment to change radically from those predominating during original asset design.

Furthermore, since the 2007 banking crisis, capital has become more expensive and harder to obtain. These factors re-emphasise the need to maximise the use of existing water industry capital assets, which because of their nature, do lend themselves to productive re-use.

What is required to avoid costly premature asset write-off on the one hand and discrimination against new technologies that offer a sustainable solution on the other, is an objective approach to asset investment and development that can extend the use of at least some of the existing asset base by extending its capacity and/or capability by integrating its reuse with introduction of another technology.

One final consideration is needed to ensure provision of adequate ‘future-proofing’ to the development of municipal
Our core case study was based on a municipal wastewater treatment facility serving 160,000 PE with total sludge processing capacity for indigenous sludge and sludge imports of up to 150% of indigenous sludge production, producing EU Urban Wastewater Treatment Directive-compliant wastewater. The main case study was then split into two sub-options representing real-life investment and processing alternatives: an entirely new site ‘greenfield’ development flow sheet (Table 1). The thermodynamic approach to wastewater processing previously can be summarised as the following guiding principle for design and technology selection: obtain the best net energy outcome from any processing step. Consider the basic large-scale municipal wastewater treatment flow sheet (refer to Figure 4). The waste stream being treated initially contains water and a substantial mass of soluble and suspended pollutants.

### RESULTS OF CASE STUDIES

<table>
<thead>
<tr>
<th>Process stage</th>
<th>Enhancement results from</th>
<th>Cost consequence as a non-integrated item</th>
<th>Process sustainability gain from optimal system integration of item</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chemically enhanced primary treatment</td>
<td>Chemical dosing</td>
<td>Additional minor capital cost</td>
<td>BOD load downstream reduced by 27–36%; aeration savings downstream</td>
</tr>
<tr>
<td>EH enhanced mesophilic anaerobic digestion</td>
<td>Upstream EH digestion capacity</td>
<td>Additional operational cost</td>
<td>Primary sludge capture up by 40–70%</td>
</tr>
<tr>
<td>Sludge dryer</td>
<td>Not enhanced: part of 'conventional' flow sheet where it is already best integrated with digestion</td>
<td>Additional significant capital cost Additional operational cost</td>
<td>Carbon negative digestion Ratio of primary to secondary sludge increased by chemically enhanced primary treatment: 30% increase in biogas SAS digestion increased: further 11% increase in biogas 90% efficiency in use of biogas by using biogas for sludge dryer and surplus heat from dryer to heat digesters and EH plant Allows UHT gasifier energy reclaim to be boosted from approx 150 kWh/tDS to 640 kWh/tDS (Innovative Logistics and Pyromex 2009)</td>
</tr>
<tr>
<td>UHT sludge gasifier</td>
<td>UHT digested sludge gasification process</td>
<td>Additional substantial capital cost Additional operational cost</td>
<td>Oxygen-limited combustion hence lower carbon footprint than incinerator For power export to UK national grid, eligible for two ROCs (currently £100/MWh) additional to renewable power contract price</td>
</tr>
</tbody>
</table>

Screening effectively removes gross suspended contamination and combined with grit removal and recovery, protects downstream equipment from the adverse effects of grit and screenings. Primary treatment then removes suspended material above a certain size (crude sewage particles below 28 μm are unsettles in a water industry primary tank; those above 117 μm all settle). The primary sludge consists of a mixture of mineral and organic sludge and typically contains 72% VSS (volatile solids). Biological oxygen demand (BOD)/chemical oxygen demand load passing out of the primary treatment into aerobic biological treatment is converted into biomass when it is catabolised; the consequent oxygen demand and need for aeration is the most significant energy demand in secondary treatment.

The waste biomass (sludge) produced is typically 82% VSS. However, when the waste sludge is subject to downstream MAD, 58% of the primary sludge VSS can be degraded and converted to valuable biogas, but only 35% of the waste biological sludge VSS can be degraded (this fraction can be less if sludge age is long). The value of biogas is that it can be used as boiler fuel for heating (~90% efficient), or combusted in a gas engine or micro-turbine to produce electricity on site (typically ~35% efficient in the former case to ~45% in the latter, with the former being the present industry standard). So, not only does secondary aerobic treatment consume significant energy for oxygen and recycle pumping, its waste sludge itself is also less amenable to digestion and produces less biogas.

Taking a thermodynamic approach, optimal processing and energy recovery will be provided by maximising primary tank efficiency to boost solids recovery. As a large fraction (typically ~60–70%) of the BOD load is solids associated, i.e. particulate, this not only offers a more digestible sludge to downstream MAD but also reduces BOD load onto biological secondary treatment producing two benefits—less waste biological sludge and lower oxygen demand, hence lower aeration energy demand.

The MAD process can also be up-rated to convert it from a carbon-positive operational status (net carbon production) to carbon-negative status by installing some form of sludge hydrolysis (Barber 2009). The standard water industry MAD reactor with secondary digestion was designed to a particular minimum retention time consistent with pathogen control standards—not to optimise biogas production, which would require a longer retention time for optimal digestion of biological sludge. Therefore, MAD reactors can produce more biogas when retrofitted with some form of high-rate hydrolysis immediately upstream of the MAD tanks.

The conventional benchmark plant used in the case study includes UK sludge processing best practice: provision of sludge drying to provide a stable, pasteurised product for final disposal of sludge to the agricultural landbank as fertilizer. The dryer provision was optimally integrated into the conventional benchmark plant flow sheet by ensuring biogas from digestion was used to fuel the dryer, and dryer waste heat used to heat the digestion plant (~90% efficient use of biogas).

The same approach was applied to the sustainable flow sheet. The sludge dryer provides a relatively secure route to return phosphorus to agricultural land. In fact, fertiliser costs have become so high that farmers in some areas of the UK are now paying the water company for sludge disposal to their land to obtain the lower cost phosphorus it offers. Pre-drying the sludge with the systems integrated to maximise the value of biogas means that any post-digestion incineration or gasification of the sludge avoids using incinerator or gasifier heat and power to dry the sludge, making more energy available for in-situ renewable power production. The conventional flow sheet leaves ~70% of raw sludge calorific value in the sludge for final disposal, so application of the principle of obtaining the best net energy outcome from any processing step here demands consideration of the introduction of forms of sewage sludge combustion into the flow sheet, to maximise energy recovery.

The sludge dryer is retained in the optimal process flow sheet for two reasons. On a best value of sludge assessment, the sludge offers two principal high value returns—in terms of phosphorus to agricultural land or sludge to combustion. In terms of sludge to combustion, this is especially significant as some of the improvements installed also reduce the ultimate calorific value remaining in the digested sludge (Table 2), which may make alternative end uses of the sludge offer more value under certain circumstances.
One consequence of the long asset life of water company assets, is that any medium- to long-term assessment of asset whole life cost sensitivity to power cost inflation needs to be sufficiently ‘long term’. It is the long-term average power cost that is important in this look ahead to 2040 for UK-based water company assets and to do so, previous long-term trends in UK and international power cost inflation have been used to provide an estimate of most probable average power cost inflation between 2010 and 2040.

Even with access to long-terms power cost inflation data, there are trends now emerging that may not have been as prominent in the past (e.g. peak oil and convergence between gas and oil prices). Given such risks to projections, this study also provides a power cost inflation sensitivity analysis.

From 1970 to 2000, a period which included a previous oil price shock event, the total power cost inflation for industrial electricity consumers reached 351% in the UK; for comparison it was 355% in the USA (both are total inflation the period 1970 to 2000). The average annual power cost inflation was therefore 11.7% in the UK for this period (and 11.8% in the USA).

These figures can also be compared to Table 3. Overall, a likely but conservative assumption for annual power cost inflation from 2010 to 2040 of 10% is reasonable. Given the pressures on price described above, it is likely to be greater than 10%.

The NPV calculations of whole life cost were based on the parameters presented in Table 4. The first scenarios examined were green-field developments of 160,000 PE or wastewater treatment with 150% extra sludge processing capacity for sludge imports from smaller satellite works. The conventional benchmark consisted of preliminary and primary treatment, secondary biological treatment by diffused aeration activated sludge, and associated final settlement tanks and sludge thickening and anaerobic digestion, followed by dewatering and drying. The sludge dryer and digestion were optimally coupled, in energy terms for a large site, by fuelling the dryer with biogas and using dryer waste heat for digestion heating.

The two sustainable green-field options developed presented different approaches to optimising whole life costs while minimising external energy demand and hence minimising CRC carbon footprint. One was based on plastic media filters (PMF), to minimise inherent energy demands for aerobic biotreatment; this was the higher capital cost of the two sustainable options. The second option was based on sequencing batch reactor (SBR) technology and offered a lower capital cost sustainable option, which did however, have a higher inherent energy demand.

The benchmark conventional option had an inherent energy consumption of 20.8 MWh/day for wastewater treatment excluding digestion, equivalent to 4.4 MW overall for all processes combined. Some 54% of site power need was met by on-site generation through sludge digestion (conventional MAD), which left a national grid power requirement of 2.0 MW. Based on 523 kg CO2 per MWh, this was equivalent to a CRC operating carbon footprint of 9,162.9 tonnes per annum.

In comparison the SBR option had an inherent energy consumption of 15.6 MWh/day for wastewater treatment excluding digestion, equivalent to 4.0 MW overall for all

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**Table 2** | Calorific values reported recently for UK sludge types

<table>
<thead>
<tr>
<th>Sludge processing</th>
<th>Calorific value (MJ/kg)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chemically enhanced primary treatment (mixed, co-settled)</td>
<td>9.6</td>
</tr>
<tr>
<td>Conventional mesophilic anaerobic digestion: digested sludge</td>
<td>12.7</td>
</tr>
<tr>
<td>Enhanced digestion (EEH system)† digested sludge</td>
<td>11.0</td>
</tr>
<tr>
<td>Mixed primary and biological waste sludge (approx 50:50)</td>
<td>17.2</td>
</tr>
</tbody>
</table>

†EEH = Enhanced enzyme hydrolysis. After Barber (2007).

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**Table 3** | UK industrial electricity power cost variations

<table>
<thead>
<tr>
<th>Recent UK annual industrial power cost inflation charges</th>
<th>Per annum rate</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>1979–2007</td>
<td>6.70%</td>
<td>BERR</td>
</tr>
<tr>
<td>1997–2007</td>
<td>3.30%</td>
<td>Eurostat</td>
</tr>
<tr>
<td>2004–2007</td>
<td>11%</td>
<td>Eurostat</td>
</tr>
<tr>
<td>2006–2007</td>
<td>18.5%</td>
<td>BERR</td>
</tr>
<tr>
<td>2007–2007</td>
<td>14.20%</td>
<td>BERR</td>
</tr>
</tbody>
</table>

BERR: department of business, enterprise and regulatory reform.
<table>
<thead>
<tr>
<th>Parameter context</th>
<th>Parameter</th>
<th>Value used</th>
<th>Provenance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital cost</td>
<td>Discount factor</td>
<td>5.7%</td>
<td>PR04 WACC: 5.7%</td>
</tr>
<tr>
<td>Payback period</td>
<td>Set to project period</td>
<td>40 Yrs</td>
<td>Arbitrary project life</td>
</tr>
<tr>
<td>Loan rate</td>
<td>Capital loan</td>
<td>4.6%</td>
<td>Gross cost real debt finance UK Water</td>
</tr>
<tr>
<td>Operating costs</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Power</td>
<td>Power (electricity-industrial)</td>
<td>£0.063/kWh</td>
<td>Inflation adjusted to 2010</td>
</tr>
<tr>
<td>Power cost inflation</td>
<td>% annual price change</td>
<td>0% to 14% inflation</td>
<td>Theoretical breakeven point to 2004–2007 annual average</td>
</tr>
<tr>
<td>Chemical-dosing</td>
<td>NaOH, NaOCl</td>
<td>2010 adjusted costs</td>
<td>Operating data 2007</td>
</tr>
<tr>
<td>Chemical-sludge-polymer</td>
<td>Dry polymer</td>
<td>£4,000/tonne</td>
<td>Operating data 2007</td>
</tr>
<tr>
<td>Chemical cost inflation</td>
<td>% annual price change</td>
<td>4.3%</td>
<td>UK RPI 2007</td>
</tr>
<tr>
<td>Salaries/salary inflation</td>
<td>% annual price change</td>
<td>2.5%</td>
<td>UK RPI 2007, site staff only</td>
</tr>
<tr>
<td>Biogas value–exported electricity</td>
<td>Power EXPORT to grid cost benefit/kWh</td>
<td>£0.04/kWh</td>
<td>Renewable power-short term contract price</td>
</tr>
<tr>
<td>Biogas value–exported electricity-ROCS</td>
<td>Renewable obligation certificates pence/MWh</td>
<td>£50</td>
<td>Digestion as MAD = 0.5ROC; Incineration = 1ROC; gasifiers = 2ROCs</td>
</tr>
<tr>
<td>Gasifier conversion efficiency</td>
<td>Sludge to electrical power conversion efficiency</td>
<td></td>
<td>UHT gasifier; Fixed bed gasifiers; Co-fired gasifiers</td>
</tr>
<tr>
<td>End use cost benefits</td>
<td>Sludge value realised at disposal</td>
<td>NONE</td>
<td>2010 market prices</td>
</tr>
<tr>
<td>Maintenance</td>
<td>% of capital plus major replacements</td>
<td>1.5% of capital for Greenfield projects; 2% for refurbishment</td>
<td>Reference projects</td>
</tr>
<tr>
<td>Whole life costs</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Full NPV</td>
<td>Asset life cycle</td>
<td>40 Yrs</td>
<td>Average between civil and main mechanical assets</td>
</tr>
<tr>
<td>NPV measurement point</td>
<td>Comparison prior to major mechanical replacements</td>
<td>30 Yrs</td>
<td>Up to present HMGovernment guarantee for ROCs</td>
</tr>
</tbody>
</table>
processes combined. Some 84% of site power need was met by on-site generation through chemically enhanced primary treatment and enzyme hydrolysis (EH) enhanced digestion. Surplus power of 0.2 MW from digested sludge gasification was exported to the national grid. The overall remaining power demand from the national grid for the treatment works was 0.6 MW. Again, based on 523 kg CO₂ per MWh, this was equivalent to a CRC operating carbon footprint of 2,748.8 tonnes per annum: only 30% of the conventional option.

The PMF-based option had an inherent energy consumption of 11.7 MWh/day for wastewater treatment excluding digestion, equivalent to 4.2 MW overall for all processes combined. Some 88% of site power need was met by on-site generation through chemically enhanced primary treatment and EH enhanced digestion. Surplus power of 0.2 MW from digested sludge gasification was exported to the national grid. The overall remaining power demand from the national grid for the treatment works was 0.4 MW. Based on 523 kg CO₂ per MWh, this was equivalent to a CRC operating carbon footprint of 2290.7 tonnes per annum: only 25% of the conventional option.

The effect of this difference in power consumption on whole life costs is apparent in Figure 5. It is the extra power cost that causes the whole life cost of the conventional works design to maintain a high rate of increase in whole life cost throughout the 40-year period examined. Despite the SBR option costing an extra 8% in capital investment and the PMF option costing an extra 28%, both become cheaper in whole-life cost terms by 10 years of operation. Minimising the cost of power purchased by the operator combined with the value of the renewable electricity exported to national grid offers a substantial hedge against these challenges to operational cost efficiency while simultaneously reducing carbon footprint.

Figure 6 demonstrates that an advantage is maintained for the sustainable options, even without UK renewable energy subsidies (ROCs). Without these subsidies there is a greater difference between whole life cost of the PMF and SBR options, with the lower capital differential of the SBR option from the benchmark resulting in a whole life cost advantage emerging after 10 years for the SBR option, but that whole life cost advantage not emerging until after 20 years for the PMF option.

Comparison of Figures 5 and 6 illustrates the value of ROCs. They are intended by the UK Government as an incentive for investment in renewable power generation and they do so in this study. With ROCs and at 10% power cost inflation, the whole life cost advantage of the SBR option emerges within a year; for the higher capital PMF option it takes 6 years. This places both options in a financial position where they can provide quick return on investment over the lower capital cost conventional benchmark. However, without ROCs, another option emerges—to further reduce carbon footprint. If we assume that ROCs are not available by or after 2040, then at that point, the assets already procured which have been used up to that point to maximise ROCs returns can be operationally managed thereafter to minimise carbon footprint. This approach
merely requires abandonment of the power export to the national grid and use of that power in-site at the works.

For example, this would decrease the carbon footprint of the PMF based option to only 10% (916.2 tonnes carbon (dioxide) per annum) of the conventional option. The carbon footprint of the SBR-based option would also be reduced by the same method: to only 20% of the conventional option or 1832 tonnes carbon per annum. This is potentially a useful reserve option in that it may coincide with a period when carbon footprint reduction has even more emphasis than is apparent in asset operational efficiency considerations now.

The sensitivity of whole life cost of the three green-field developments is illustrated in Figure 7. As power cost inflation increases, the conventional option with its reliance on externally supplied power becomes progressively more expensive while the sustainable options obtain a double benefit from increasing power costs: reduced power supply costs and increasing revenue from power exports.

Having examined the whole life cost implications for green-field development of large municipal sewage treatment plants in the UK to mitigate power cost inflation, reduce carbon footprint and provide strategic resource recovery, this investigation then considered asset development towards the same objectives for refurbished large-scale sewage treatment works.

Water company assets have a long asset life and high capital value, so high write-off costs encourages the industry to maximise the use of its assets. As a result, many municipal wastewater treatment asset development projects are refurbishments of existing assets rather than green-field site developments. The tendency for long asset life to lead to exposure to changes in regulation within the asset life, requiring change in asset capability and for municipal
populations to grow, necessitating change in asset capacity, reinforces a tendency toward refurbishment projects.

Similar technology interventions were utilized to those used for the green-field sites, but this time centred on the conventional benchmark site as the core existing asset. The core asset in each theoretical development project was therefore a 160,000 PE capacity municipal wastewater treatment works with 150% extra sludge processing capacity for sludge imports from smaller satellite works. The base assets for refurbishment again consisted of preliminary and primary treatment, secondary biological treatment by diffused aeration, aerated activated sludge and associated final settlement tanks, and sludge thickening and anaerobic digestion, followed by dewatering and drying. The sludge dryer and digestion were again already optimally coupled, in energy terms for a large site, by fuelling the dryer with biogas and using dryer waste heat for digestion heating.

A variety of ‘enabling technologies’ were considered but based on thermodynamic considerations and the need to provide value for money for capital investment, these were confined to chemically enhanced primary treatment, EH enhanced digestion, and digested sludge gasification or incineration.

While Table 1 presents the potential advantage of these technologies, their combination will not always be synergistic. For example, chemically enhanced primary treatment increases primary sludge yield, but part of that increase is a mineral sludge that will occupy digestion volume to no positive end, and will reduce the calorific value of the digested sludge through ‘dilution’ (refer to Table 2). This will reduce potential power recovery margins on downstream...
### Table 5 | Summary of energy and operating carbon outcomes for capital interventions (upgrading options) to improve conventional sewage works

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Power recovered by investment option (kW)</th>
<th>Net electricity demand MWh/day</th>
<th>Renewable power export MWh/day</th>
<th>Power related annual carbon footprint (tonnes CO₂e)</th>
<th>UK CRC carbon saving (tonnes CO₂e)</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional best practice</td>
<td>None</td>
<td>21.29</td>
<td>None</td>
<td>4,064.15</td>
<td>0</td>
<td>Benchmark: includes sludge drying and digestion</td>
</tr>
<tr>
<td>Enhanced primary treatment only</td>
<td>108.4</td>
<td>18.69</td>
<td>None</td>
<td>3,567.90</td>
<td>496.25</td>
<td>Chemically enhanced primary treatment</td>
</tr>
<tr>
<td>Enhanced digestion only</td>
<td>369.4</td>
<td>13.45</td>
<td>None</td>
<td>2,567.04</td>
<td>1,497.11</td>
<td>Enzyme Hydrolysis system upstream of MADs</td>
</tr>
<tr>
<td>Enhanced primary treatment and digestion only</td>
<td>421.3</td>
<td>11.18</td>
<td>None</td>
<td>2,134.51</td>
<td>1,929.64</td>
<td>Chemically enhanced primary treatment plus enzyme hydrolysis system upstream of MADs</td>
</tr>
<tr>
<td>UHT gasifier only</td>
<td>1,171</td>
<td>7.80</td>
<td>13.58</td>
<td>1,488.22</td>
<td>2,575.94</td>
<td>Ultra-high temperature gasifier. Gasifier surplus heat used to heat dryer along with biogas</td>
</tr>
<tr>
<td>Incinerator only</td>
<td>1,206.5</td>
<td>6.49</td>
<td>13.1</td>
<td>1,238.91</td>
<td>2,825.25</td>
<td>Incinerator surplus heat used to heat dryer along with biogas. Incinerator generated electricity exported</td>
</tr>
<tr>
<td>Dual fuel (natural gas co-fired gasifier) only</td>
<td>1,479.1</td>
<td>4.43</td>
<td>17.6</td>
<td>845.66</td>
<td>3,218.49</td>
<td>Conservative assessment. Fixed bed gasifier. Gasifier surplus heat used to heat dryer along with biogas. Natural gas co-fired. Renewable power exported to grid and biogas surplus used to reduce on-site power demand from grid</td>
</tr>
<tr>
<td>Dual fuel (upgraded biogas co-fired gasifier) only</td>
<td>734.0</td>
<td>22.30</td>
<td>17.6</td>
<td>4,256.96</td>
<td>−192.80</td>
<td>Conservative assessment. Fixed bed gasifier. Gasifier surplus heat used to heat dryer along with biogas. Upgraded biogas co-fired. Gasifier renewable power exported to grid</td>
</tr>
<tr>
<td>Enhanced digestion with UHT gasifier</td>
<td>1,469.5</td>
<td>0.00</td>
<td>10.3</td>
<td>0.00</td>
<td>4,064.15</td>
<td>Enzyme hydrolysis system upstream of MADs with UHT gasifier and gasifier surplus heat recovery for drying</td>
</tr>
<tr>
<td>Enhanced primary treatment and enhanced digestion with UHT gasifier</td>
<td>1,288</td>
<td>0.00</td>
<td>5.97</td>
<td>0.00</td>
<td>4,064.15</td>
<td>Chemically enhanced primary treatment plus enzyme hydrolysis system upstream of MADs with UHT gasifier and gasifier surplus heat recovery for drying</td>
</tr>
</tbody>
</table>

Net electricity demand is here defined as power demand after all internal site generation for on-site use has been taken into account.
processing such as incineration or gasification. In addition, thermodynamic considerations alone may not determine whole life costs outcomes. For these reasons, the enabling technologies were also combined and optimally integrated as far as possible, confining extra capital expenditure for their integration to that of the asset upgrades themselves plus no more than extra power generation (e.g. gas engine) or recovery (e.g. heat exchangers and condensers) equipment for the combined assets.

The outcomes are presented in Figures 8–13 and Tables 5 and 6. In Figure 8, at 10% annual power cost inflation the best enabling technology options in purely whole life cost terms over 40 years are provided by two options: the combination of enhanced primary treatment, enhanced digestion and ultra-high temperature (UHT) gasifier or enhanced digestion and UHT gasifier only. The operating cost advantage and maximising the value of capital is sufficient to achieve recovery of that extra capital investment within a year (Table 6) for both options. The enhanced primary treatment, enhanced digestion and UHT gasifier option is not, however, the best overall in energy export terms. That outcome is offered by the enhanced digestion and UHT gasifier option, which provides higher calorific value sludge for the gasifier than the option with enhanced primary treatment included. Although enhancing primary treatment can provide more biogas via digestion, if the sludge retains a higher calorific value at gasification the overall energy recovery appears to be more efficient. The whole life cost is almost identical between these two options (Figure 8), but a marginally better whole life cost at 30 and 40 years is offered by the enhanced digestion and UHT gasifier option.

The best overall whole life cost, CRC carbon footprint and power export potential is offered by enhanced digestion combined with digested sludge gasification.

The lowest capital investment option, offering low whole life cost and best rate of return on investment plus good CRC carbon footprint and power export potential, is offered by UHT gasification of digested sludge. This is the consequence of the bulk (approximately 70%) of the energy, expressed as calorific value, still remaining in the digested sludge by the conventional works (Figure 8, Tables 5 and 6).

The upgraded biogas co-fired fixed bed gasifier option illustrates how significant optimal systems integration is in securing the potential returns reported in this study. In this option, a less efficient (fixed bed) gasifier (Laughlin 2003; McCahey 2003) is combined with co-firing of upgraded biogas. This takes biogas away from the sludge dryer and as a result, undermines the overall energy efficiency of the integrated process flow sheet. Co-fired gasification (Takahashi 2007) which is not properly integrated into the process flow sheet, in the sense that the best overall energy balance is secured, undermines the cost benefit obtained by ROCs. It still offers a better whole life cost outcome than the conventional flow sheet, but the rate of return on investment drops to 22 years even with ROCs. The cost of capital for biogas upgrading equipment to clean biogas for co-firing the gasifier, combined with the gasifier now providing heat for sludge drying, substantially alters the energy balance and whole life cost outcome.

UHT gasifier based solutions are robust and provide good carbon footprint reductions, which still offer the best whole life cost outcomes even without energy subsidies such as ROCs (Figure 9). The effect of the ROCs becomes immediately apparent when return on investment is

**Table 6 | Payback periods for capital investment interventions (conventional plant upgrades) at 10% power cost inflation**

<table>
<thead>
<tr>
<th>Enabling technology</th>
<th>With ROC subsidy (years)</th>
<th>Without ROC subsidy (years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>UHT gasifier</td>
<td>1</td>
<td>11</td>
</tr>
<tr>
<td>EH enhanced digestion and UHT gasifier</td>
<td>1</td>
<td>12</td>
</tr>
<tr>
<td>Enhanced primary treatment, EH enhanced digestion and UHT gasifier</td>
<td>1</td>
<td>19</td>
</tr>
<tr>
<td>Fixed bed natural gas co-fired gasifier</td>
<td>12</td>
<td>29</td>
</tr>
<tr>
<td>Fixed bed upgraded biogas co-fired gasifier</td>
<td>22</td>
<td>Not determined</td>
</tr>
<tr>
<td>Incinerator</td>
<td>4</td>
<td>13</td>
</tr>
<tr>
<td>Enhanced primary treatment, EH enhanced digestion and incinerator</td>
<td>6</td>
<td>16</td>
</tr>
</tbody>
</table>
considered, as this drops from a year to 11–19 years for UHT gasifier based options without ROC subsidies. However, without ROC subsidies, plant operational management can shift from power export to obtain ROCs to maximising site CRC carbon footprint reduction, as described previously.

The significance of how much calorific value remains in the sludge, even after enhanced digestion and enhanced primary treatment (Table 2) is also emphasised by solutions that avoid digested sludge combustion or pyrolysis (Figure 10). Without combustion, energy recovery has practical limits. As a result of this restriction on overall energy recovery potential, the whole life cost of the upgraded conventional plants still increase with power cost inflation, but at a lower rate.

CONCLUSIONS

The process flow sheets developed in this investigation were conformed to the market conditions prevalent in the UK. Although power cost risk, carbon mitigation risks and strategic resource recovery risk are global phenomena, optimal solution development will reflect the national legislative and regulatory environment. So, for example, the optimal process flow sheets developed in this study which offer the municipal wastewater plant operator a route to strategic resource recovery for phosphorus via sludge as fertilizer to the agricultural landbank, would not be appropriate in the Netherlands (EnergieFabriek 2009). A Netherlands-based solution would need to include struvite harvesting, or a similar process (Guney 2009), for phosphorus recovery.

Resource recovery of benefit to municipal sewage plant operations and overall operational efficiency over the next 40 years is unlikely to be confined to phosphorus recovery only. Increasing regulation on wastewater final discharge quality and the price of some chemicals will make upgrade of existing plants to biological nutrient removal (BNR) status more attractive in future. The problem that confronts BNR in temperate climates is low levels of VFA (volatile fatty acids) formation in the sewer and hence low VFA levels in the crude sewage. Rather than chemical dose, BNR capability could be supported by VFA harvesting from EH enhanced digestion, based on overall cost benefit. There is a range of possible future products from sewage sludge (Norlow & Wawyrzynczyk 2009) that suggests that over the next 60 years, municipal wastewater treatment operations will increasingly include elements of resource recovery.

The enabling technology approach to maximising reuse of existing assets in order to minimise capital cost and embodied carbon lends itself to staged investment. Not all the upgrade option elements need to be introduced at the same time. Enhanced digestion or enhanced primary treatment could be introduced during one investment cycle for large municipal sewage treatment works, with sludge combustion introduced later. The key to successful staged investment is ensuring that the process design includes consideration of all the key elements and how they integrate at the initial investment stage, then checking that that design intent is carried through to the full solution provision.

There is an alternative to the enabling technology approach presented here. Anaerobic whole stream treatment works well in warm climates and should be considered for such applications. However, in temperate climates the returns from whole stream anaerobic treatment are more marginal, even for membrane-based systems (Jefferson 2009). These technology developments may struggle to contend with flow and load variation and asset write-off costs, but may offer potential solutions for medium-sized works in particular. For example, anaerobic whole stream treatment with upstream primary treatment for load buffering and solids feed to stabilise the bioreactor load should be investigated for small or medium sewage treatment works. Small (rural) works optimal sustainability solutions seem more likely to be offered by constructed wetlands, partially aerated lagoons and reed beds where land is available but anaerobic whole steam treatment may develop a niche as a solution for small- to medium-sized sewage treatment works for green-field developments in particular.

For an energy efficiency strategy to deliver the potential benefits outlined in this paper, the terms of reference for asset development must be sufficiently comprehensive. The boundary conditions for the proposed development must not artificially exclude significant potential sources of renewable energy. For example, United Utilities (Black & Rands 2008) reported on two asset development case
studies for refurbishment and extension of the main sewage treatment assets only of two sewage treatment works using the shadow price of carbon method. Their conclusions were that the shadow price of carbon would have to reach £83/tonne, before the method decided in favour of the sustainable asset investment option, which is based on more than 5% difference in option NPV provoked by the shadow price of carbon. However, this study drew the project boundary around the wastewater treatment assets only. From the thermodynamic approach described previously in this paper, the calorific value remaining in sewage sludge even after digestion is a significant potential energy recovery factor. Even recovery of only part of the 70% remaining calorific value in digested sludge can significantly change the investment outcome, especially when exploitation of that opportunity is combined with maximising energy efficiency and integrating process systems to that end. Using this paper's stated approach with the same boundary conditions drawn by Black & Rands (2008) produces a similar outcome to that reported by them. So, the boundary conditions drawn for an investment project can determine the outcome—sometimes to the exclusion of some of the full range of opportunities the asset under development could offer. Project boundary conditions must be set with care.

Comparison of Figures 6 and 7 illustrates the value of ROCs to asset developers. They are intended by the UK Government as an incentive for investment in renewable power generation and they do meet precisely that need for large municipal sewage treatment works. These subsidies are currently guaranteed until 2037, but their absence does not remove the business case for hedging against power cost risk to operational efficiency and operating cost offered by sustainable water industry asset development. That approach still offers UK water industry asset developers time to take advantage of these quicker returns on investment before 2037. Given the competition for capital resulting from various, competing UK water company asset commitments, securing the asset base advantages described in this paper requires UK water companies to develop a forward-looking investment strategy that is longer term than present planning. The investment period this study addresses covers 2010 to 2040 but to obtain the best value for capital on offer from renewable energy subsidies, UK water companies need to start making these particular capital investments now (Palmer 2007, 2008). Service providers to the water industry are taking these factors into account and best practice for project development and project management toward optimal asset base whole life cost development by sustainable methods is already available (Nair & Palmer 2008).

In the UK, the privatised water companies have their asset development and investment planning reviewed by an economic regulator, OFWAT. All UK water companies are seeking to minimise costs while providing security of service for potable water supply, public health protection and environmental protection through wastewater treatment. However, the size of their assets bases and age of some assets means there is a substantial capital maintenance requirement as well as the need to invest in new capacity and upgrade asset capability to meet new regulations. This places strains on the current 5-year investment review cycle, which OFWAT has been proactive in acknowledging. The economic regulator now advocates 25 year planning now for UK water companies, but given present water company asset commitments, it is difficult to see how this empowers UK water companies in terms of effective, sustainable, long-term investment to mitigate climate change advocated in this paper, unless the UK water companies are also able to submit 25 year budgets, which allow them to weight their spending to the start of the 25 year period.

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REFERENCES


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