Hydro-BPT | Energy Recovery in Water Services
Adennill Ynni yn y Diwydiant Dŵr

Trinity College Dublin
Coláiste na Tríonóide, Baile Átha Cliath
The University of Dublin

PRIFYSGOL BANGOR UNIVERSITY

TOWARDS A MORE SUSTAINABLE SYSTEM OF WATER SUPPLY IN IRELAND AND WALES: EXPLORING OPPORTUNITIES FOR MICRO-HYDROPOWER IN THE WATER INDUSTRY

PROJECT INSIGHTS
MAY 2011 - JUNE 2015

SOUTHERN & EASTERN Regional Assembly
Promoting Our Region

IRELAND WALES 2007 – 2013

Ireland's EU Structural Funds Programmes 2007 - 2013
Co-funded by the Irish Government and the European Union

EUROPEAN REGIONAL DEVELOPMENT FUND

Summary

Towards a More Sustainable System of Water Supply in Ireland and Wales: Exploring Opportunities for Micro-Hydropower in the Water Industry

The supply and treatment of drinking water and the collection and treatment of waste water is an energy intensive and unsustainable process in its current form. In Ireland and Wales this water industry is the 4th most energy intensive sector contributing significantly to CO_2 emissions and incurring high costs, ultimately borne by the public. One method to improve the sustainability of the water industry is the recovery of energy in water pipe networks using Micro-Hydropower turbines at points of high excess pressure in the system.

The HydroBPT Project commenced an investigation of Micro-Hydropower (MHP) in the water industry in Ireland and Wales in May 2011. During this investigation the project examined over 300 water infrastructure sites across Ireland and Wales for their suitability for MHP energy recovery. It was estimated that the existing water infrastructure in Ireland and in Wales each have the potential for the recovery of over 10 GWh of electricity per annum. This is equivalent to a combined annual saving of over €2.5 million and over 10,000 tonnes of CO_2 emissions.

The technical feasibility of recovering this energy potential was also investigated by the HydroBPT project. Engineering design guidelines were developed for MHP energy recovery at water and waste water infrastructure sites. Water pipe network optimisation software was also developed to enable the optimum location and number of MHP turbines to be installed in a given network, to be determined maximising energy production while maintaining acceptable pressure standards.

A life cycle assessment of the installation of several previous MHP energy recovery projects in the water network were examined in detail, identifying the carbon payback for such installations and the key components contributing to embodied carbon and resource depletion in their design and construction. The carbon payback for MHP energy recovery within the water network was shown to be achieved within a handful of months in all cases examined. In addition to this a new Eco-Design methodology was developed and implemented to further reduce the carbon payback and impact on natural resources of MHP energy recovery projects.

Best practice business and organisational management models were also investigated during the project to enable the water industry to accelerate their implementation of MHP in practice through supportive management structures and strong business case material. Examining a number of management approaches in the region a 5 stage management framework was developed to best support implementation and reduce barriers to implementation.

The impact of long-term flow variation and climate change on the economic viability of MHP energy recovery in water networks was also assessed. New engineering design guidelines were developed to cater for changes in water demands in future. In addition predictive models were developed to enable the estimation of the extent of future changes in flow rate. These new tools will enable MHP design to

be resilient to the uncertainty that climate change can create on the economic viability of investing in MHP for the water industry.

This project insights report presents a selection of the research carried out in the HydroBPT project across its key work packages: Engineering, Environmental Impact, GIS; Business/Collaboration, and Future Risk Factors. In total the project produced 34 separate publications on various topics within this framework. The full publication list is contained within the Appendix of this report.

Table of Contents

Summary……i

Table of Contents……iii

Acknowledgements……iv

1. Introduction……1
An introduction to the aims and objectives of, and context for, the Hydro-BPT project. *McNabola, A. Coughlan, P. Williams, A.P.*

2. Background……5
Energy recovery in the water industry using micro-hydropower: an opportunity to improve sustainability. *McNabola, A., Coughlan, P., Corcoran, L., Power, C., Williams. A.P., Harris, I., Gallagher, J., Styles D.*

3. Engineering……16
Energy recovery potential using micro-hydropower in water supply networks in Ireland and Wales. Corcoran, L. Coughlan, P. McNabola, A.

Development of an evaluation method for hydropower energy recovery in wastewater treatment plants: Case studies in Ireland and Wales. Power, C. Coughlan, P. McNabola, A.

4. GIS……40
A strategic assessment of micro-hydropower in the UK and Irish water industry: identifying technical and economic constraints. Gallagher, J. Harris, I.M. Packwood, A.J. McNabola, A. Williams, A.P.

5. Environmental Impact……51
Life cycle environmental balance and greenhouse gas mitigation potential of micro-hydropower energy recovery in the water industry. Gallagher, J. McNabola, A. Styles, D. Williams, A.P.

6. Business and Collaboration……61
Innovation and the water industry: case studies of innovation, education and collaboration. Corcoran, L. Coughlan, P., McNabola, A.

7. Future Risk Factors……80
The impact of long-term flow variation and climate change on micro-hydropower turbine efficiency in water supply networks. Brady, J., Gallagher, J., Corcoran, L., Coughlan, P. McNabola, A.

References

Appendices
Project Publications

Acknowledgements

The HydroBPT Project was funded from May 2011 to June 2015 by the Interreg IVA 2007-2013 Ireland Wales Programme. This project contributed to Priority 2 Theme 1 of the programme on climate change and sustainable development.

The Ireland Wales Programme 2007-2013 has an overall aim of addressing issues relating to innovation, entrepreneurship, the knowledge economy, climate change and community regeneration between both countries. Meaning 'inter-regional', INTERREG is an EU Community Programme that aims to strengthen economic and social cohesion by promoting international and cross-border co-operation.

More information on the work carried out by the project can be found at www.hydro-bpt.eu and more information on the Ireland-Wales programme can be found at www.ireland-wales.ie.

1. Introduction

An introduction to the aims and objectives of, and context for, the Hydro-BPT project

Aonghus McNabola[a], Paul Coughlan[b], Prysor Williams[c]

[a] *Dept of Civil, Structural & Environmental Engineering, Trinity College Dublin, Ireland*
[b] *School of Business, Trinity College Dublin, Ireland*
[c] *School of the Environment, Natural Resources and Geography, Bangor University, Wales*

1.1 Introduction

The water industry is heavily reliant on energy for the extraction and treatment of raw water, the distribution of treated water and the collection and treatment of waste water. The industry is the 4th most energy intensive sector in Ireland and Wales and is responsible for considerable contributions to climate change. The Hydro-BPT project comprises an exploration of the use of micro-hydropower (MHP) technology in the water industry to reduce its energy consumption, improve environmental performance and sustainability. This exploration was carried out from technical, economic, environmental and business management perspectives.

The primary aim of this project was to present the water supply and hydropower industries in Ireland-Wales with a clear framework from which to create economic activity and to improve the sustainability of water supply, reducing its climate change impacts. This aim was achieved by delivering on the following 5 objectives:

1. Assessment of the technical and economic feasibility of applying MHP to water infrastructure: using numerical and experimental models the energy recoverable from Break Pressure Tanks (BPTs), Service Reservoirs (SRVs), Pressure Reducing Valves (PRVs), and waste water treatment plants (WWTPs) will be assessed. This section of the project will enable the development of design guidelines for implementation e.g. flow and pressure ranges required for useful energy recovery; influence of diurnal flow patterns on energy outputs; system reliability and by-pass; turbine design guidelines; system layout; etc. Using the design guidelines developed lab scale pilot plants will also be developed to demonstrate the practical implementation of this technology to industry.
2. Assessment of the Environmental Impact of applying MHP technology to water infrastructure: the environmental impact of this technology will be assessed in terms of the potential CO_2 emissions saving, assessment of negative impacts, impacts on affordability of water supply in Ireland-Wales; carbon foot-printing and life cycle assessment (LCA).
3. A feasibility study for the application of hydropower in existing Irish and Welsh water infrastructure: information on the existing Irish and Welsh water networks will be gathered from local authorities and other relevant sources in a geographic information system (GIS) database. This database will enable us to assess the feasibility of MHP around the Ireland-Wales region for energy recovery purposes e.g. location, layout, water flow/pressure, diurnal variations, national grid connectivity, energy potential. The results of the GIS study will be used to demonstrate the untapped energy potential in existing water supply networks in Ireland-Wales. This element of the project will also use the GIS database to determine the capital costs, operating costs & Return on Investments (ROI) for the development of the potential sites identified.
4. An exploration of the forms of collaboration among the key stakeholders: Local authorities, hydropower specialists and engineering researchers, as a group need to transition from a strategic network to a learning and transformational network of collaborators to implement this new technology in practice. This section of the project addresses the business/organisational aspect of developing MHP in the water industry and will develop a mode of collaboration with the active involvement of key stakeholders, reflect on its effectiveness in practice and develop guidelines for implementation by SMEs, water companies/authorities for the widespread roll-out of this concept.
5. To quantify the impacts of climate change, energy price & government policy on the viability of MHP energy recovery in the water network: Climate change directly and indirectly impacts on the energy recovery potential of the water network. Similarly, the future price of energy will influence the economic viability of such energy recovery. Policy such as water pricing or incentivisation of hydropower will significantly affect flows within

water networks or economic viability. The Hydro-BPT project will quantify these effects and link them to MHP design guidelines.

1.2 Context: the Ireland-Wales programme 2007-2013

The *Ireland-Wales Territorial Co-operation Programme 2007-2013* (INTERREG 4A) aims to further develop Irish Welsh co-operation in the areas of employment, innovation, climate change and sustainable development. *INTERREG* means 'Inter-regional' which represents the building of links between regions in the *European Union*. Managed in Ireland by the Southern and Eastern Regional Assembly on behalf of the *Irish Government*, the *Welsh Government* and the *European Commission*, the Programme is part-funded by the *European Regional Development Fund* (ERDF). The Programme has two Priorities, each containing two themes:

Knowledge, Innovation and Skills for Growth
- Theme 1: Innovation and Competitiveness
- Theme 2: Skills for Competitiveness & Employment Integration

Climate Change and Sustainable Regeneration
- Theme 1: Climate Change and Sustainable Development
- Theme 2: Sustainable Regeneration of Communities

The Hydro-BPT project contributes to Priority 2 on *Climate Change and Sustainable Regeneration*, under Theme 1, *Climate Change and Sustainable Development*. In addition the work of the Hydro-BPT project is focused within the geographic area defined by the Ireland-Wales Programme as show in Figure 1.1.

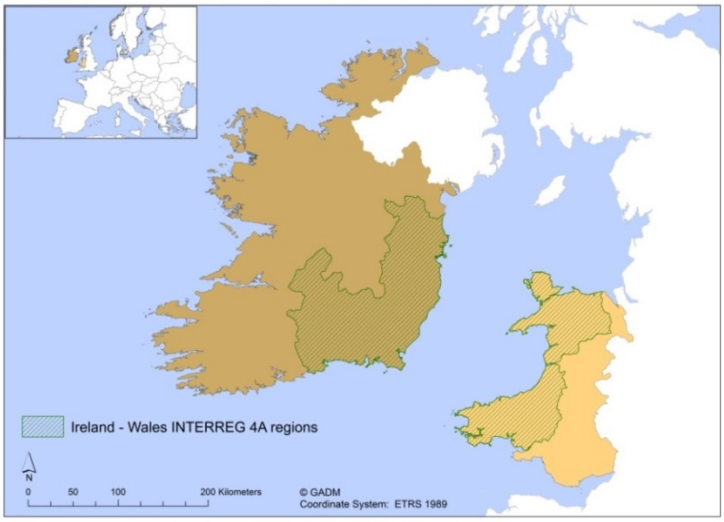

Figure 1.1 – Ireland Wales Programme Area, 2007-2013, including in Ireland: Dublin, Meath, Kildare, Wicklow, Carlow, Wexford, Kilkenny, Waterford, South Tipperary, Cork & Kerry; In Wales: Isle of Anglesey (Ynys Mon), Gwynedd, Conwy, Denbighshire, Ceredigion, Carmarthenshire, Pembrokeshire, Swansea, Flintshire & Wrexham.

1.3 Hydro-BPT project report

This report presents some of the insights gained through the work of the Hydro-BPT project between May 2011 and June 2015. The project work was structured into 5 main work packages and this report presents some of the key insights gained in each of these thematic areas. These areas explored the opportunities for MHP technology in the water industry from the perspectives of:

- Engineering: examining technical feasibility; design guidance; system optimisation; development of lab scale MHP prototypes.

- Geographic Information Systems: demonstrating the spatial distribution of MHP energy recovery opportunities in Ireland and Wales; facilitating economic and environmental impact assessment.
- Environmental Impact: quantify the CO_2 emissions saving potential of MHP in Irish and Welsh Water infrastructure; life cycle assessment of MHP technology; development of Eco-Design strategy.
- Business and Collaboration: establish how best energy recovery projects can be implemented and replicated in practice from organisational and management perspectives.
- Future Risk Factors: Assess the impact of long-term flow variation and climate change on the energy recovery potential of MHP technology.

This report presents some highlights from the insights of the Hydro-BPT project in each of the above themes in sequence. Prior to this the following section outlines the background to energy consumption and environmental impact in the water industry world-wide. Various aspects of the project work are also contained in the 34 publications listed in the Appendix which will provide more detail to those who wish to investigate this field of research further.

1.4 Hydro-BPT project team

The Hydro-BPT Project was a joint cross-border collaboration between the Schools of Engineering and Business at Trinity College Dublin in Ireland and the School of Environment, Natural Resources and Geography at Bangor University in Wales.

For further information please contact us at:

Dr. Aonghus McNabola
Dept of Civil, Structural & Environmental Engineering,
Trinity College Dublin,
Ireland.
Tel: +353 1 896 3837
Mail: amcnabol@tcd.ie

Dr. Prysor Williams
School of Environment, Natural Resources and Geography,
Bangor University,
Wales.
Tel: +44 1248 382637
Mail: prysor.williams@bangor.ac.uk

2. Background

A review of energy recovery in the water industry using micro-hydropower

Aonghus McNabola[a], Paul Coughlan[b], Lucy Corcoran[a], Christine Power[a], A. Prysor Williams[c], Ian Harris[c], John Gallagher[c], David Styles[c]

[a] Dept of Civil, Structural & Environmental Engineering, Trinity College Dublin, Ireland
[b] School of Business, Trinity College Dublin, Ireland
[c] School of the Environment, Natural Resources and Geography, Bangor University, Wales

2.1 Introduction

The supply of treated water in the western world is an unsustainable process in its current form due to the considerable amounts of energy consumption and CO_2 emissions inherent in the various treatment and supply processes involved. With the increasing global awareness of the impacts of energy consumption and CO_2 emissions on climate change, humankind, finite resources and the environment as a whole, efforts to reduce such impacts are underway in all sectors of society.

The sustainability of the water supply process and its contribution to climate change is a global concern for large urban centres [1]. Recent research in the water supply industry has identified key research questions in the area, such as: '*how do we develop and implement low energy water treatment processes?*' and '*can we optimise water supply within catchments?*' [2]. Research has also identified the need to focus innovation in wastewater as a resource for potable water, materials and energy [3].

The record global population has resulted in an all-time high in water demand. Transporting and treating water to meet water quality standards is an expensive and energy intensive processes. The ever increasing stringency of water quality legislation across the world has added to the cost of water supply and treatment [4]. This, coupled with the rapidly rising costs of energy will adversely affect the extraction and conveyance of water in future [5].

Many methods of improving the sustainability of water supply have been investigated. Methods aimed at reducing overall water demand and subsequently its associated energy consumption include: the reuse of grey water; water leakage reduction and pressure management schemes; rainwater harvesting schemes; water metering and other water conservation policies [4, 6]. Methods to reduce the energy consumption of individual water/wastewater treatment processes have also been investigated. These include the capture of by-products such as: biogas for use in combined heat and power facilities [7]; generation of energy from wastewater treatment through anaerobic bioreactors or microbial fuel cells [3]; recovery of waste heat; recycling of dried sludge pellets in co-firing combustion systems [8]; energy efficient desalinations systems; etc.

The focus of the Hydro-BPT project, using micro-hydropower (MHP) technology in water pipelines and other water infrastructure, has also shown potential to improve sustainability [9]. At points of high excess pressure in water supply networks, energy may be recovered using MHP technology without interfering in the water supply service [10]. However, while significant potential is reported in the literature, only limited penetration of this concept has been put in place by the water industry in practice.

This paper presents a review of energy consumption and CO_2 emissions in the water industry. In addition an assessment of the opportunities and challenges for the recovery of energy using MHP systems is outlined. This review and assessment incorporates the technical, economic, environmental and organisational perspectives which influence the potential of this energy recovery concept.

2.2 Energy use and CO_2 emissions in the water industry

Globally, 2-3% of energy usage is reported to be associated with the production, distribution and treatment of water [3]. In the United States, it is estimated that 5% of national energy consumption is associated with water services. At city level, 30-60% of local government expenditure has been reported to be associated with water services, where the energy consumption requirement thereof is the single largest expense within budgets. Energy prices are rising and their effects on the cost of water supply have been highlighted in literature Sustainability of urban water system: examples from Fukuoka, Japan [5].

The water industry is the 4th most energy intensive industry in the United Kingdom, responsible for 5 million tonnes of CO_2 emissions annually and consuming 7.9 TWh of energy in 2006/7 [11]. In Brazil, 60-80% of water industry costs are reported to be associated with the distribution of water; consuming an estimated 9.6 TWh annually at a cost of approximately 1 Billion US Dollars or 14% of the annual Brazilian electricity budget [12]. In much smaller economies, such as Ireland, the operation of the water industry has been reported as costing over €600 million annually [13].

The distribution of water accounts for 45% of energy use in the water industry, representing the single biggest source of energy use associated with the provision of water services [3]. Indeed, the pumping of water in California is reported to be the largest single use of electricity in the state [14]. Water is heavy and the transport of water over long distances against large rises in elevation is expensive and energy intensive. The remaining portion of energy consumption in the water industry is consumed in wastewater management (29%) and water treatment (26%). It has been estimated that 0.8 kWh of energy is required per cubic metre of wastewater treated in Norway, twice the amount of energy required to supply the same volume of drinking water [15].

The increasing political efforts to improve water quality across the globe have seen water service companies invest in high-tech, energy intensive treatment facilities. Indeed the ever increasing stringency of, for example, the EU water quality directives has served to increase the energy consumption of the water industry over the past decade [16]. These rising monetary and energy costs in the water industry require intensified research efforts to improve the sustainability of the process overall.

As outlined earlier, efforts to reduce the energy consumption of the water industry are now underway on several fronts including the use of MHP as a means of energy recovery. The best available estimate of the hydropower potential in the UK water industry for example is 17 MW [17], with a 9 MW capacity of installed at present [18]. In the Ireland Wales Interreg region an estimated 2 MW of energy recovery potential was demonstrated in existing infrastructure during the Hydro-BPT project [19]. The following sub-sections outline reported research findings of energy recovery using MHP.

2.3 Energy recovery in the water industry

2.3.1 Micro-hydropower systems

MHP systems comprise a means of converting the energy of flowing fluid into mechanical and subsequently electrical energy on a small scale (<100-300 kW). These systems may be suitable for providing energy for a typical house or small community depending on the magnitude of the fluid resources available. As such, MHP could be considered as a form of decentralised hydro electric energy conversion. The energy available from a particular MHP installation is a function of the fluid flow rate and available head at that particular site. It is also a function of the efficiency at which the available energy resource may be converted to electrical energy, commonly in the range or 50 to 75% depending on turbine type and flow/head conditions. The costs of MHP installation are reported to be in the region of €3,000-6,000 per kW [9].

MHP systems have been installed in numerous locations across the globe and have been particularly popular in developing countries; with tens of thousands of such installations in countries like China, Nepal, Sri Lanka and other East Asian and African countries [20]. In recent years, MHP installations in western countries have also become more widespread. Sites in which it is technically and economically viable to produce hydropower on a large scale have become increasingly scarce. In addition, the more environmentally friendly nature of MHP and the associated lower costs (which made it popular in developing countries) have increased its attractiveness [21]. Furthermore, the international focus on energy sustainability and climate change has been a driver in this activity.

2.3.2 Origins of energy recovery in the water industry

Some of the earliest published records of research in this area were carried out by Williams [22], who identified the scope for MHP use as a form of energy recovery in water pipelines. It was identified that there are many instances in water supply networks where control valves are in place to manage downstream pressure. Here the installation of a MHP turbine could achieve the same reduction in pressure required while simultaneously recovering some of the available energy [23]. Thus energy could be generated for use by the water service provider without reducing the level of service to consumers and reducing the cost of water production and supply.

This hypothesis was tested at a control valve, acting as a pressure management control in a water supply system in the UK. The control valve was located in the vicinity of an isolated new chemical dosing plant which required 4 kW of power for operation. The available resource of 50 l/s and 36 m of head was sufficient to recover an estimated 17 kW of power. As this exceeded the local energy demand, an energy recovery MHP scheme was constructed whereby only a proportion of the flow was diverted through the turbine, sufficient to generate the 4 kW required by the chemical dosing plant. With the total investment in this energy recovery infrastructure costing €44,000 and also saving the expense of a connection to the grid (estimated at €62,000), the scheme was an obvious success. More recently this has also been demonstrated at PRVs using pump as turbine (PAT) technology [24].

Other similar installations are known to pre-date this example, with energy recovery installations in Germany [25] and Scotland [22]. In Vartry reservoir, Ireland, a MHP system was put in place in 1947 to recover energy from flow between an upper storage reservoir and the treatment plant below. The MHP plant was later decommissioned and the belt driven Pelton turbine was recently upgraded in with a 90 kW plant, generating sufficient energy to operate the works and sell the excess to the grid (Figure 2.1). Such cases are commonplace at older water storage and treatment facilities, whereby older MHP turbine technology was sufficient to meet the power demands of treatment facilities in the earlier parts of the 20th century. However as water treatment regulations became more stringent and hence more energy intensive over time, many of these hydropower installations were no longer fit for purpose and fell into disrepair. With later advances in turbine technology and overall plant efficiencies, as well as the introduction of renewable energy Feed In Tariff (FIT) schemes to incentivise hydropower production, many schemes have since been refurbished.

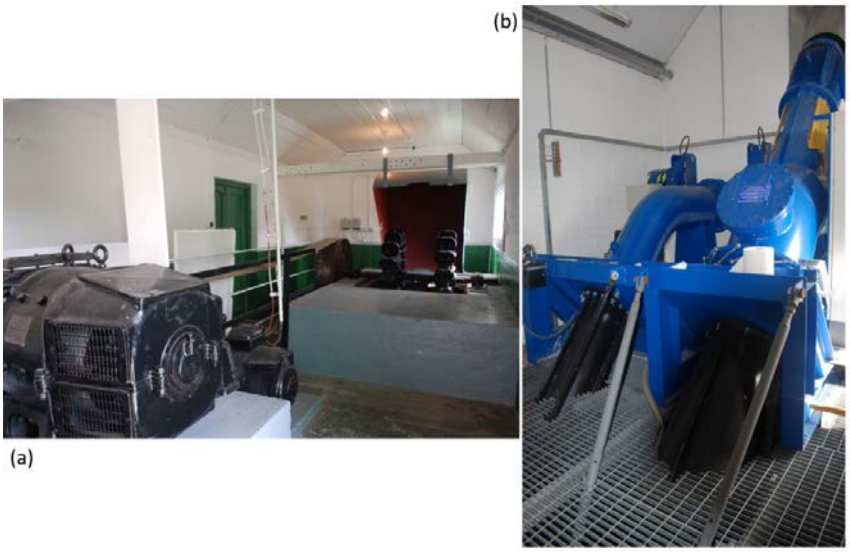

Figure 2.1 – a) 90 kW MHP energy recovery system (1947) Vartry Reservoir, Ireland; b) 90 kW MHP energy recovery system upgrade, Vartry Reservoir, Ireland.

Clearly a precedent for the recovery of energy in water supply systems using MHP has existed long before international pressures on renewable energy, sustainability and climate change arose. However in response to these today, renewed focus on this concept is emerging in the literature [24, 26-28]. Furthermore of those hydropower installations in the water industry today, the vast majority could be described as the 'low hanging fruit' of the total pool of potential resources available. It is likely that many suitable sites for energy recovery exist within the water infrastructure but that their potential remains untapped.

2.3.3 Energy recovery in water supply infrastructure

Investigations examining the recovery of energy in water supply systems have included studies on PRVs, control valves (CVs), break pressure tanks (BPTs) and storage/service reservoirs (SRVs) [9].

PRVs

PRVs aim to reduce the pressure of flow passing through them to a preset level. Their use in the water industry has become widespread in response to drives to reduce leakage losses in the system through pressure management. The installation of PRVs also prevent exceedances in downstream hydraulic grades [29]. PRVs are a more versatile solution to pressure control than their predecessor, the BPT. Owing to their size, likely higher costs and increased risks of water contamination, the BPT has become a less popular design solution. In addition PRVs offer the additional functionality of reducing pressure to a range of values as opposed to a single value in the case of a BPT.

Replacing a PRV with a MHP turbine has been shown in the literature to be a feasible mechanism of both reducing pressure and recovering useful energy in certain circumstances [24, 26-28]. Placing a MHP turbine in parallel with a PRV and bypassing the valves allows system operators to recover energy while maintaining the integrity of the water supply system should the turbine break down [30]. In the US, a commercial assessment of 6 PRV sites reported an estimated energy recovery potential of 500 kW. A demonstration plant was subsequently constructed at one of the sites, however the completed MHP installation produced just 5-15 kW, lower than initial estimations of 35 kW [31].

An investigation of the energy recovery potential of 23 PRVs in Brazil found a mean energy recovery capacity across the valves of 10 kW with a range of 2.6-40 kW [21]. The majority of these PRVs were in place on 50 mm ID pipelines where the mean energy recovery capacity was typically 8 kW. One PRV in the dataset was in place on a larger 110 mm ID pipeline which was estimated could produce over 40 kW of electricity. However, the system efficiency used of 90% in this investigation could be considered an optimistic efficiency to take account of all system losses. Furthermore this investigation and many others of this nature have failed to account for the variation in flows and pressure which is likely to occur across a typical day, week and seasonally. Thus, such estimates of energy potential do not present the full picture and may overestimate the scale of the resource.

An investigation of a PRV in a section of the water supply network in Napoli, Italy estimated an energy recovery potential of 9.5 kW [32]. However, the estimates of cost were considerably lower than those adopted by the majority of investigations in this field. Furthermore, no consideration was given to the long-term uncertainty in any of the influencing variables of the Hydro-PRV system, such as flow, pressure, energy prices, etc.

An investigation in Canada examined the feasibility of MHP within the water distribution network from a probabilistic perspective in order to address the issue of demand variation [33]. A number of other potential uncertainties were flagged, including, long-term demand growth, diurnal and seasonal demand variations, pipe friction coefficients and future cost fluctuations. They concluded that because demand is uncertain, a probabilistic framework should be used in calculations when deciding on the viability of a MHP installation.

An investigation in Ireland examined the potential of 30 PRVs and control valves for energy recovery purposes [34]. The existing PRVs were found to have a mean potential for energy recovery of 8.5 kW based on average flow and head conditions, while results varied from 0.1-47 kW. Examination of the potential of the existing control valves showed higher energy potential with a mean of 94 kW. However, it was also highlighted by the authors that the potential energy recovery potential at such water infrastructure based on yearly average flow and head data may be misleading. It was noted that flow, head and turbine efficiency vary considerably as would the subsequent power production.

Carravetta et al. [27] outline a methodology for the installation of a pumps as turbine (PAT) in place of a PRV to generate electricity and control downstream pressure while catering for changes in incoming flow and pressure. This variable operating strategy was achieved using hydraulic and electrical regulation of the PAT. PATs have also been noted to be considerably less expense to install in comparison to traditional turbines [24], however the peak efficiency of these devices is lower than many other turbine types. In addition the small scale of the output capacity of many PRV sites, typically in the range of 5-15 kW as shown by Corcoran et al. [35], is too small for many conventional turbines to be economically viable in this case. Therefore the PAT may be the most viable option for combined energy recovery and pressure management in water supply networks.

Break pressure tanks

BPTs offer a similar functionality to a PRV. However the BPT reduces pressure in a pipeline by creating a breaking in the system where the flow is open to the atmosphere. When this occurs all the pressure that had built up in the pipeline is dispelled to the atmosphere and the continuation flow is driven by its potential energy from the break point onwards. For energy recovery purposes, a MHP turbine may be installed prior to the break point to recover energy without interfering with the level of pressure in the system downstream of the BPT.

An investigation in Ireland examined the energy recovery potential of 7 existing BPTs [10]. It was reported that the mean energy recovery potential was 12 kW (range 2 – 27 kW). Several of the BPTs examined were found to be financially viable as Hydro energy recovery installations, however again these estimates failed to address the long-term uncertainty in flow or energy related system variables.

In addition to the earlier observations on flow variation, many investigations have also omitted the variation in turbine and system efficiency with flow rate and pressure resulting in further inaccuracies in estimations. Furthermore studies of this nature have also failed to address the long term reliability of such energy recovery systems. MHP installation in a water supply network may be at risk of significant changes in flow and pressure conditions from the original design values. Should a new water demand arise upstream of a PRV or BPT, then flow and pressure may be significantly altered rendering the MHP installation no longer viable.

Storage/service reservoirs

Storage or service reservoirs in this context comprise water storage infrastructure. Service reservoirs are typically used in a water supply system to balance the diurnal demands in a section of the distribution network while storage reservoirs are used to feed a large portion of the entire network by gravity. Service reservoirs are commonly fed by gravity but many storage reservoirs are fed via pumped mains and would be unsuitable for energy recovery in this context.

A study in Portugal of an interconnector main flowing by gravity between two reservoirs found that for a mean flow of 120 m^3/day over a drop in head of 22.5m, the annual energy production would amount to 2.28 GWh (i.e. a 260 kW plant). The value of this energy recovery was estimated at €0.05 /kWh, equating to €113,800 per annum [12]. A similar investigation in Ireland, which considered a number of service reservoirs, estimated the recoverable energy at 12-115 kW

depending on the particular tank in question. The reservoir with the highest energy capacity was estimated to have the potential to generate over €144,000 annually in electricity [10].

Of the available estimates in the literature, service reservoirs have shown the highest energy recovery potential in many cases, followed by BPTs and PRVs. However, in many cases the return on investment estimation has not accounted for FIT incentivisation, available in many countries, or the savings costs of electricity to the water industry (including all taxes and charges) as opposed to the unit price.

2.3.4 Wastewater infrastructure

The flow of sewage effluent can also be directed through a penstock under pressure, through a MHP turbine to recover energy in wastewater treatment infrastructure [9]. This can be carried out at treatment works outfalls or inflows; and the inlet to pumping station wet wells or in sewer mains where sufficient flow and pressure is available.

Investigators have reported on the feasibility of sewage-treatment outfalls for energy recovery using pumps as turbines (PATs). For example, a demonstration project built in 1993 in Switzerland used a PAT to produce up to 210 kW of electrical power from a sewage outfall [23]. In India a demonstration energy recovery plant has been constructed on a sewage storage tank located on a University campus. Although the plant capacity was reported as just 190 W, the project was still deemed economically viable [36].

However, more notable and successful examples of energy recovery at treatment works outfalls can be seen in Sydney, Australia. Here wastewater flow of 330 Ml/day (dry weather flow) over a 60 m drop in head at a deep sea outfall has been used to recover energy, generating approximately 12 GWh annually. It is estimated that the plant will offset 80,000 tonnes of CO_2 emissions annually as a result of this energy recovery [37].

In the UK, an Archimedes screw turbine has been installed to recover energy from the outfall pipe of a wastewater treatment plant. Two turbines in series are reported to produce a total of 180 kW, saving the water service provider €160,000 in annual electricity costs [38].

Similarly an energy recovery feasibility study was carried out at another wastewater treatment plant in the UK, which included a 3.3 km long sea outfall pipe with a 40 m drop in head [39]. The mean energy potential at the site was estimated to be 177 kW within the range 149-193 kW. Energy production estimates varied with the diurnal variations in dry weather outflow from the treatment works. The effects of variations in turbine efficiency and tide levels were also included in the analysis as was the design of the plant and a suitably reliable bypass system. The investigation estimated a capital cost of €560,000 but an income from electricity generation of approximately €11,000 per annum.

In Ireland, the feasibility of MHP energy recovery at a number of wastewater treatment plant outlets was also examined. Low heads were reported for the majority of plants investigated resulting in only those with significant daily flow demonstrating useful potential [40]. The largest energy recovery potential was reported as 133 kW at the country's largest wastewater treatment facility.

No studies were found which examined the feasibility of energy recovery using MHP at the inlets to pumping station wet wells or in large sewage collector mains. Further research in this area is required to gauge the feasibility of such operations.

2.3.5 Economic viability

The economic viability of MHP energy recovery systems in the water industry is the key question which remains to be comprehensively addressed in literature. Numerous research investigations,

as listed above, highlight the existing or theoretical energy potential of various water infrastructure sites, but fail to examine the potential variation of such average energy potential estimates. Water flow and pressure are known to vary significantly throughout a typical day, from day to day, weekday to weekend, by season and over the longer term. Water flow and pressure are also subject to significant changes due the addition of new industries, new demands, water charging or water saving schemes etc. Such changes in flow and pressure would have a significant influence on the efficiency of a turbine converting the excess energy to electricity.

Turbines are typically designed for a particular design flow and variations as either increases or decreases in flow and head will result in reductions in power production. The extent of the reduction will depend on the magnitude of the change in flow conditions and the type of turbine in question. For example, a 50% increase or decrease in the design flow for a PAT would result in a reduction in energy conversion efficiency from typically 80% to less than 30%. PATs have been cited in several investigations as a suitable turbine for energy recovery in water pipelines [22, 23, 32]. Changes in the average flow in a water pipeline of 50% or more is a common occurrence in water supply networks.

Aside from the aforementioned technical limitations in existing feasibility studies, sufficient scrutiny of the economic viability, in terms of revenue generation, is also lacking in studies of this nature. Many investigations determine the annual return from a hydropower installation using the unit price of electricity or using the local FIT rate of hydropower generation. However the economic viability of such installations is influenced to a very significant degree by the end use of the electricity generated. Plants which use the electricity on-site will make a saving on electricity purchases at market rates while plants which sell the electricity to the grid will do so using the local FIT rate. The savings electricity purchases includes not only the unit price but also any taxes or duties applied to the supply of electricity such as sales tax, value added tax and carbon tax. Many studies fail to account for the actual cost to the water industry of electricity savings including all taxes and charges. Furthermore, studies also fail to determine the effect on plant feasibility of future changes in energy prices. Electricity prices vary significantly across Europe, for example from as little as €0.08 /kWh in Bulgaria to as much as €0.29 /kWh in Denmark.

For plants which have no use for electricity generated on site, selling to the gird will provide a longer return on investment as FIT rates are typically lower than consumer price of electricity including all taxes and charges, but higher than the market rates. An exception to this exists in the UK where the FIT rate for MHP is particularly high. FIT rates vary significantly across different countries and previous investigations have failed to examine the sensitivity of proposed energy recovery sites to the value of the FIT rate.

2.3.6 Environmental impact

Primary environmental concerns in relation to the water industry relate to the depletion of freshwater resources and pollution arising from inadequate wastewater treatment. Freshwater resources per capita vary widely, for example from less than 1,000 m^3 per capita in the Czech Republic and Cyprus, to over 20,000 m^3 per capita in Finland and Sweden, within the EU [41]. It is projected that climate change will reduce the availability of freshwater in lower mid-latitude regions such as the Mediterranean and increase the frequency of severe droughts [42]. According to the UNEP [43], one third of the world's population currently live in countries suffering from moderate or high water stress (where water consumption is more than 10% of renewable freshwater resources), and this is projected to increase to two thirds of the world's population by 2030. An important secondary impact from the water industry is the consumption of energy, usually entailing the depletion of non-renewable resources (fossil fuels), and associated greenhouse gas (GHG) emissions [44].

The use of energy in the water industry contributes to its carbon footprint. This is a measure of the total amount of GHG emissions, expressed as CO_2 equivalents according to their global

warming potential, that result from an activity or series of activities involved in the life cycle of a product [45]. Most of the energy used by the water sector is in the form of electricity, with an associated carbon footprint of between less than 0.1 kg CO_2e per kWh for nuclear and renewable generated electricity to over 0.9 kg CO_2e per kWh for coal generated electricity. Average emission factors are 0.38 and 0.57 kg CO_2e per kWh, respectively, for the EU27 and US [46]. The water industry in the United States is responsible for 5% of total US carbon emissions annually [47]. In the UK, emissions associated with water supply and treatment are estimated to average 0.34 and 0.7 kg CO_2e per m^3, respectively, totalling 5.01 Mt CO_2e per year in 2010/11 [48], equivalent to approximately 1% of UK GHG emissions. Energy consumption and GHG emissions from the water industry are related to local freshwater availability. In regions where demand exceeds availability from freshwater resources, freshwater is pumped long distances from regions of water surplus, or produced from desalination, incurring considerable energy consumption and GHG emissions. In Italy, investigations have estimated that the carbon footprint of public water supply is 0.9 kg CO_2e per m^3 [49]. The carbon emissions associated with the water industry worldwide are likely to grow if current trends are not reversed due to: rising water demand; limited and remote locations of fresh water; more stringent and energy intensive water treatment regulations and technology.

Investigations have highlighted the effects of numerous water management and water supply scenarios on the carbon footprint of specific systems. An investigation in the US compared 5 water management scenarios to the baseline scenario and found that the carbon footprint of existing water services in Las Vegas was 0.84 million tonnes CO_2e per annum. It was also found that increases in demand for water could increase this figure by over 12% by 2020, and that increasing renewable energy input could reduce emissions by over 20% [44]. In Florida, US, a similar investigation examined the effect of 20 water infrastructure expansion alternatives on the carbon footprint of the service [50]. The investigation examined the expansion of the Manatee County water supply system in the period 2011 to 2030 using options such as exploiting further ground water, surface water, transferring regional water and others. Transferring raw water from regional sources was estimated to result in the highest carbon footprint of 2.26 million tonnes CO_2e over the assessment period. However, no investigations have been found during this review which examined the effects of widespread implementation of MHP energy recovery on carbon footprints in the water industry. Further research is required to investigate the potential impact of this on the water industry. This gap in research will be explored further in Section 5 of the Hydro-BPT Project Report.

Within the UK, the water industry does contribute to national GHG emission reductions through renewable energy generation. In 2010/11, 877 GWh were generated by the UK water industry [48], equivalent to a saving of approximately 0.521 Mt CO_2e. Over 90% of this energy is sourced from anaerobic digestion in wastewater treatment plants, suggesting that renewable energy generation (or at least energy capture) from the supply network may be underexploited. Capturing energy from the supply system could help the water industry meet its proposed target for 20% of energy to be sourced from renewable sources, which would exceed the advised 15% target set out by the government for 2020 [51]. Investigations have also highlighted the equivalent CO_2 emissions savings of a number of potential sites or demonstration projects. In Ireland, an investigation of 7 BPTs and 3 service reservoirs estimated a potential CO_2 emissions saving of 1,350 tonnes annually [10].

2.3.7 Organisational challenges

For an energy recovery project to be implemented within the water industry, it is necessary for a number of stakeholders to come together, such as local government, water utilities, electricity suppliers and regulators, turbine manufacturers, etc. Effective collaboration between this network will ensure the successful, cost- and time-effective implementation of such schemes. If attention is paid to the development of a strong collaboration network from the early stages, it could also increase and encourage future collaborative projects to be implemented. In a recent paper by Gausdal and Hildrum [52], a framework for network development for inter-firm

networks in the water technology industry was developed. How the researchers facilitated group meetings, encouraged dialogue and progressed from dialogue to action with a focus on trust building amongst the network was outlined.

To encourage collaboration between different organisations in the water and energy industries it is necessary to first investigate and understand these organisations, including both their structure and characteristics and previous collaborative history. Over 90% of the approximately 250,000 water service systems worldwide are municipally owned water and wastewater utilities, while only 8% are privately operated and/or owned [3]. The water industry comprises asset owners, operators, engineering specialist (design & constructions), and suppliers of equipment. On the supply side the industry includes the following technologies: water filtration membranes, UV radiation, biological water-cleansing processes and energy efficient recycling of sludge and industrial wastewater. On the demand side, the customer base includes waterworks, sewer plants and construction firms. There is a significant growth potential in this industry as the global demand for clean water and the need for energy-efficient water purification increases.

Within the boundaries of the industry, the networks of firms may collaborate on joint R&D projects and enhanced water cleansing technologies. However, there may not be a history of trust to enable firms to engage in progressively more complex and risky collaboration activities. The challenges of the need for development and innovation translate into the need for collaboration among firms in the industry and, even, the establishment of new firms to exploit the new technologies. This collaboration requires trust and can take time to emerge [53].

The evolution of networks of firms, with contractual bases for their relationships, brings to mind the twin concerns of competition and collaboration [53]. Competition comes easily to firms whose focus is on the market. Further, collaboration comes (relatively) easily to firms who have an interest in a relationship. Where it becomes difficult is where the improvement imperative requires both collaboration and competition. Then market-based relationships need to be re-visited in an environment of potential reconciliation, a search for sustainability and a reduction of risk. Here, working to achieve sustainable strategic improvement and a corresponding transition from a strategic to a learning and transformational network is a problem, the resolution of which requires time and thoughtful application of resource.

Further research in this field is required to develop a model of organizational collaboration between the water and energy industries. This may then facilitate the more widespread implementation of energy recovery technology in water infrastructure. This topic is explored further in Section 6 of the Hydro-BPT Project Report.

2.4 Discussion and conclusions

It can be seen from the available literature that energy recovery using MHP in the water industry is a growing area of research and industrial activity. Many successful demonstration projects are in existence and many promising feasibility studies have been carried out. However, to date the examples in existence have been implemented on an ad-hoc basis and little market penetration of this concept has occurred [17].

From this review, it is clear that further research is required in a number of key areas. Future research should aim to address the uncertainties which exist due to the variation in water demands both, daily, weekly, seasonally and in the longer term. These should also address the sensitivity of projects to changes in electricity prices and/or FIT rates. Such uncertainty creates an unacceptable risk to investment in MHP infrastructure if design conditions are open to significant change during its lifetime. These uncertainties may be part of the reason why given the vast number of suitable sites identified in the literature only a small number of MHP installation are in existence in the industry.

In addition, more detailed information on the investment costs are required to facilitate the growth of this sector. Many studies to date have used cost estimates for MHP construction, however the expenses associated with consulting, planning, connection to the grid, maintenance etc., are often neglected. In essence a more transparent and reliable model of energy recovery potential and return on investment is required for MHP energy recovery to prosper. These gaps in research are explored further in Sections 3 and 7 of the Hydro-BPT Project report.

The environmental impact of the water industry, its carbon footprint and energy consumption have all been shown to be significant on a global scale. Studies have set out to examine means of limiting or reducing the carbon footprint of the water industry, but none have included the option of the widespread implementation of MHP energy recovery systems. Quantification of the carbon footprint of MHP energy recovery in the water industry in comparison to other methods of energy saving or generation is an important missing element in the development of this concept. It has been noted that the water industry has a range of options through which it may choose to reduce its energy demand such as wind or solar power and biogas combustion. The selection of such investment options should be informed by both the economic viability of a potential scheme and the environmental benefits of the various alternatives. The environmental impact of MHP in the water industry is explored further in Section 5 of this report.

It has also been shown that the need exists for the development of collaboration models between the water and energy industries to facilitate a more widespread implementation of MHP energy recovery in water infrastructure. The governance, regulation and organisation of the water industry across jurisdictions is diverse and complex. The structure of these organisations influences the ability of the water industry to deliver on sustainable strategic improvements such as MHP energy recovery. Collaboration models shedding light on the operation of these large sets of organisations may enable the development of more effective policy to promote the implementation of MHP energy recovery in future. This together with more dissemination of research findings to industry and policymakers may act as a catalyst for the improvement of the sustainability of the water industry.

3. Engineering

Energy recovery potential using micro-hydropower in water supply networks in Ireland and Wales

Lucy Corcoran [a], Paul Coughlan[b], Aonghus McNabola[a]

[a] Dept of Civil, Structural & Environmental Engineering, Trinity College Dublin, Ireland
[b] School of Business, Trinity College Dublin, Ireland

3.1 Introduction

Previous research has highlighted that it is possible to recover energy within water supply networks through the installation of hydropower turbines. However it has been noted that flow variation and future cost fluctuations could impact project viability and also that new policies to incentivise the installation of hydropower turbines are required in order to improve project viability. This paper will investigate the effect of flow variation and turbine efficiency as well variations in energy and feed-in tariff prices on project feasibility and investment payback periods for existing water supply infrastructure in the Ireland-Wales region. The infrastructure being investigated will be those pressure reducing valves (PRVs), control valves (CV), service reservoirs (SRVs) and break pressure tanks (BPTs) that could be retrofitted with micro-hydropower (MHP) technology in order to recovery energy from the water supply process.

3.2 Methodology

3.2.1 Experiment design

This study will focus on water supply networks in Ireland and Wales. During the initial years of the Hydro-BPT project, Irish water supply was operated by the Water Services Authority (WSA). The WSA consisted of five city councils and twenty nine county councils. This since changed to one water authority, Irish Water. In contrast, the majority of the water supply services in the UK are run by private water companies. These can be seen in Figure 3.1 below. Pressure and flow data from Irish and UK water supply networks were gathered for a range of potential energy recovery locations such as PRVs, CVs, SRVs and BPTs. This section presents results from a variety of different types of schemes ranging from small rural group water supply schemes up to large urban water supply networks. The schemes examined in Ireland were located around the greater Dublin area, Dublin city and county, Kildare and Wicklow in the east and also southern areas such as Cork City, Tipperary and Waterford. The schemes examined in the UK were located in the jurisdictions of Welsh Water and Severn Trent Water (See Figure 3.1).

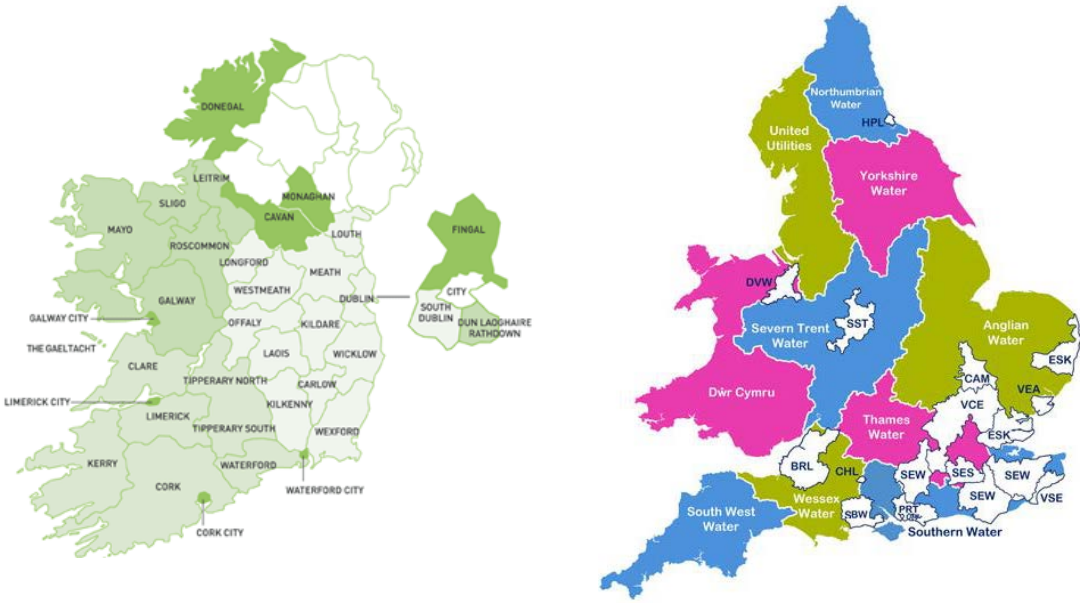

Figure 3.1 – Study location, Ireland (L) and UK (R).

Flow and pressure measurements were analysed for a range of locations. Power outputs were calculated for both varying flow rates and an average annual flow rate for comparative purposes. The effect of using an assumed constant turbine efficiency versus a turbine efficiency varying with flow rate was also investigated. Investment payback periods were calculated for a range of different feed-in-tariff rates and for use of electricity on site to compare the effect this would have on investment payback. A sensitivity analysis was also undertaken using Net Present Value (NPV) calculations.

3.2.2 Data collection

Pressure and flow data were collected for BPTs, PRVs and SRVs from water supply networks in Ireland and Wales. The nature of the data available varied for each location. Twelve months of telemetry data readings taken every 15 minutes from control valves and PRVs within the Dublin city water supply network were analysed to identify suitable locations for energy recovery. These readings were taken for the period June 2010 to August 2011. A sample of storage reservoirs, BPTs and PRVs from within the greater Dublin area and also from Cork City were also analysed to estimate their potential for energy recovery. Rural areas were also investigated, including the Clonmel Town water supply in Co. Tipperary. On a smaller scale, the Tydavnet Private Group Water Supply Scheme (GWSS) in Co. Monaghan was also investigated. Flow rate readings from the inlet and outlet of their primary supply reservoir, taken every 15 minutes from October 2010 to March 2012, were analysed. For the reservoirs and tanks in the Kildare region, only an average daily value for inlet and outlet flow and pressure was available. The data obtained for the South Dublin Region were average flows taken over the period 16th – 23rd of April 2012. The inlet and outlet pressure values were obtained for both the daytime and night-time settings for their PRVs. The Welsh Water data consisted of flow and pressure information for all PRVs on mains of over 150 mm diameter. The flow data consisted of average daily flows for the month of February 2011.

In total, 95 potential sites were examined for energy recovery potential and economic viability as part of this investigation. During the Hydro-BPT project as a whole over 238 sites were examined in the water supply network of the Ireland Wales region and over 100 sites were also investigated in the wastewater network. Details of these analyses are outline later in this Section and in Section 4 on GIS.

3.2.3 Power estimation

The estimated power output from potential hydropower installations at existing infrastructure sites was calculated using Equation 3.1:

$$P = Q\rho g H e_0 \qquad (3.1)$$

Where P is the power output, Q is the flow rate through the turbine, ρ is the fluid density, g is acceleration due to gravity, H is the head available at the turbine and e_o is the efficiency of the total system. For initial calculations, a conservative turbine system efficiency value of 65% was assumed.

Power outputs were calculated for a number of potential turbine types and the most suitable turbine was selected. These turbine efficiencies varied with the flow rate for more accurate calculations. Equivalent CO_2 emissions were calculated using guidelines published by the UK Department for Environment, Food and Rural Affairs (DEFRA) and the Department of Energy and Climate Change (DECC) [54]. The conversion factor for equivalent CO_2 emissions for purchased grid electricity was 0.52037 kg of CO_2 emissions per kWh generated.

3.2.4 Return of investment

As required by the EU Directive 2009/28/EC, Ireland must have 16% of its electricity generated by renewable sources by 2020. The primary incentive in Ireland to help to achieve this target is the Renewable Energy Feed-in Tariff scheme (REFIT). This scheme was designed to incentivise the addition of 4,000 MW of new renewable electricity to the Irish electricity grid, and more specifically to encourage the development of new renewable generation from onshore wind, small hydro and biomass landfill gas technologies [55]. The first REFIT scheme was launched in 2006, and March of this year saw the launch of REFIT 2. In 2012, the tariff for hydropower schemes with a generation capacity of less than 5 MW was approximately €0.08 per kWh (€83.81 per MWh). These REFIT tariffs are adjusted annually by the annual increase, if any, in the consumer price index in Ireland, and are available for 15 years. The plant must be operational by the end of 2015 to be eligible and the tariffs can therefore not extend beyond 2030 [55].

REFIT schemes are available in many countries and the tariffs available in Ireland are small in comparison with some other countries. The UK feed-in tariff scheme for example currently offers a variable rate depending on the power output of the site. The maximum rate of £0.21 (€0.26) per kWh is offered for the smallest MHP sites (<15 kW). While a rate of £0.04 (€0.06) per kWh is offered for larger schemes with power outputs ranging from 2 MW to 5 MW [56].

Depending on the site in question, there may also be the option of using the electricity on site rather than connecting to the grid. This can be even more economically viable as the cost of buying electricity is considerably higher than the REFIT price paid in most countries, currently in Ireland the cost to buy electricity is €0.19 per kWh. The European average electricity price for small users is €0.18 per kWh but this varies considerably from as low as €0.08/kWh in Bulgaria to as high as €0.29/kWh in Denmark [57]. However in the UK for example the REFIT scheme heavily incentives MHP and the REFIT rate is more attractive in this case. It is clear therefore that the local energy costs and incentives will influence significantly the viability of a MHP energy recovery project. This element of Section 3 examines the effect of varying REFIT and energy prices on MHP viability in water supply networks.

In general, water companies will rule out investments with payback periods of greater than ten years. The cost of installing small scale hydropower turbines is largely site specific. Costs can vary significantly depending on the amount of civil works required, type of turbine, and also on the proximity to the electric grid. However, some general estimates for the cost of installation of small hydropower can be found. The capital cost of small-scale hydropower has been said to be in the region of £3,000 (€3,700) to £6,000 (€7,400) per kW installed [9]. An American supplier and installer of hydropower turbines for water pipes estimate a cost of $3,500-7,000 (€2,800-5,600) per kW installed and also an additional estimated annual maintenance cost of $2,000 (€1,600) [33]. Some turbine types are noted to be considerably cheaper than others such as the pump as turbine [24]. However for the purpose of conservative estimation in the Ireland-Wales region, the maximum estimate of €7,000 per kW installed was used for calculations in this element of study. In addition a number of alternative cost estimation approaches are explored both here and later in this section of the report.

3.2.5 Sensitivity analysis

A sensitivity analysis was undertaken to investigate a range of potential risks and variations to feasibility calculations, and to estimate the effect of differing feed-in tariffs and energy prices on the investment payback period of these projects. An average installation cost of €5,000 per kW installed was used for calculations based on the above mentioned estimates.

Net Present Value (NPV) calculations were also used to more accurately calculate and compare future investment payback periods. The key sensitivity variables investigated with these calculations were the additional annual maintenance cost of €1,600 and a comparison of the initial investment required per kW installed, between the minimum estimated €3,000 per kW and maximum estimated €7,000 per kW. NPV calculations were calculated for a hypothetical 20 kW, 50 kW and 100 kW site. A project was considered feasible when the NPV was positive within 10 years on construction. The NPV is calculated using Equation 3.2 below:

$$\text{NPV}\ (i) = \sum_{t=1}^{N} \frac{R_t}{(1+i)^t} \qquad (3.2)$$

Where R_t is the net cash flow at a given time t, and i is the discount rate. Discount rates of 5%, 7.5% and 10% were used and compared for this analysis.

Flow and Turbine Efficiency Variation Analysis

Power output and annual power generation were calculated using average flow and pressure values as well as using more accurate varying flow rates and pressures. Finally turbine selection and variable turbine efficiency and its effect on power output estimation were also investigated.

3.3 Results and discussion

3.3.1 Data overview

The total 95 potential sites considered for energy recovery included 73 PRVs, 4 control valves, 3 BPTs and 15 reservoirs. The total power generation capacity for the Dublin City data is presented in Table 3.1.

Table 3.1 – Overview of estimated power outputs.

Estimated Power Output (kW)	Number of sites
< 5 kW	53
5 - 20 kW	27
20 - 50 kW	8
50 - 100 kW	5
> 100 kW	2

The results of the Dublin City investigation are presented in **Error! Not a valid bookmark self-reference.** and highlight that significant energy recovery potential exists.

Table 3.2 – Power output and generation estimates for 15 sites with highest power output.

	Location	Power Output (kW)	Annual Generation (kWh)	Annual CO_2 emissions savings (tonnes)
Dublin City: Control Valves	Blackhorse Bridge	98.6	863,386	449.3
	Stillorgan Road	33.6	294,189	153.1
	Merrion Gates	33.4	292,568	152.2
	Thomas Court	212.3	1,859,414	967.6
Dublin City North: PRVs	Poplar Row	17.4	152,604	79.4
Dublin City South: PRVs	Rainsford Street	28.0	245,631	127.8
	Rialto Bridge	47.0	411,429	214.1
	Slievebloom Park	26.9	235,797	122.7
Dublin Reservoirs	Saggart	115.0	1,007,323	524.2
	Cookstown	71.6	627,566	326.6
Kildare Reservoir	Old Kilcullen	30.1	263,611	137.2
South Dublin reservoirs	Belgard	56.7	496,300	258.3
Dŵr Cymru Welsh Water	Horeb Road	19.0	166,440	86.6
	Berrymead Rd. Cardiff	24.3	212,868	110.8
	Llanrhos Church	18.3	160,308	83.4

The majority of the sites investigated yielded power outputs of less than 5 kW. Power outputs in excess of 100kW were estimated for two sites. The power output values in Table 3.1 were calculated using average pressure and flow values. In practice however, flow and pressure and hence power output, vary considerably. Table 3.2 presents power outputs and annual generation and annual emissions savings for the fifteen sites with the greatest power generation potential.

3.3.2 Investment payback

Investment payback period was initially calculated for schemes at an installation cost of the maximum estimated €7,000 per kW installed. The annual revenue was initially calculated assuming a renewable energy feed-in tariff scheme was in place such as the REFIT scheme in Ireland. These payback periods were then compared with the potential payback period if no REFIT

scheme was available. For this a rate of €0.04 per kWh was assumed based on the average price paid for electricity sold to the Irish grid for non-renewable resources. For a hypothetical 100kW site in Ireland, the investment payback period with a REFIT scheme in place was calculated to be 10 years. With no REFIT available, the investment payback period was calculated to be 20 years. Finally, investment payback was calculated for situations where the electricity could be used on site, without needing to connect to the grid. This was found to be the most economic option with investment payback period achieved in 4 years.

For comparison, these investment payback periods were calculated using the Irish, UK, Bulgarian and the average European feed-in tariff rates for hydropower schemes. Payback periods varied considerably with the different tariffs. Payback was also calculated for use of electricity on site rather than connecting to the grid. These results are illustrated in Figure 3.2.

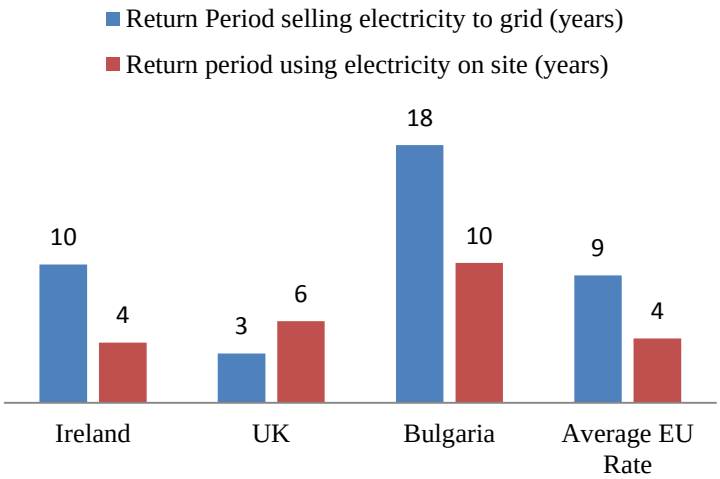

Figure 3.1 – Investment return comparison.

3.3.3 Sensitivity analysis

NPV calculations were used to predict future cashflows. These assumed a constant feed-in-tariff rate of €0.083 per kWh generated as per the Irish REFIT scheme. An annual maintenance cost of €1,200 was added each year. Three discount rates were compared, 5%, 7.5% and 10%. Installation costs of €3,000, €5,000 and €7,000 per kW installed were compared for both a 20 kW installation and a 100kW installation. The results of these calculations are shown in Figures 3.3 and 3.4.

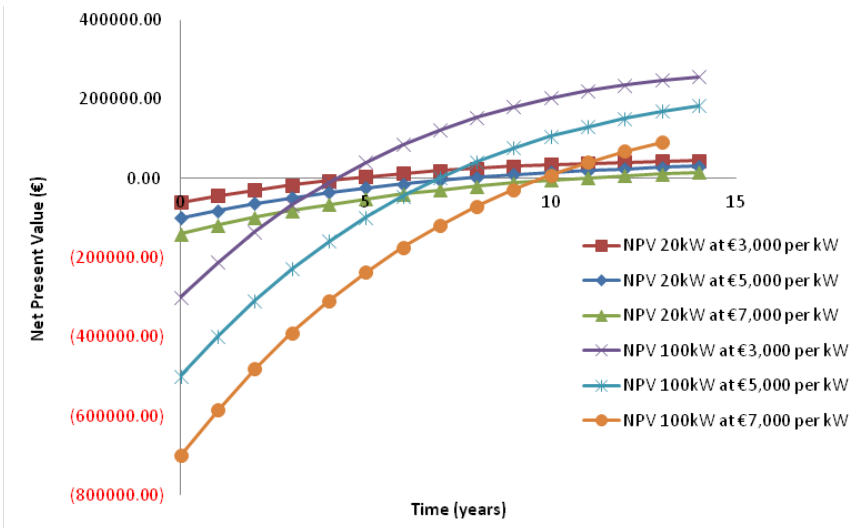

Figure 3.2 – NPV calculations at a 7.5% discount rate, for a range of installation costs and generation capacities.

The NPV of all of the cases investigated was positive by year ten. The 100kW installation at an installation cost of €7,000 per kW delivered a return on investment after year 9, while the 20kW installation for the same installation cost delivered a return on investment after year 10.

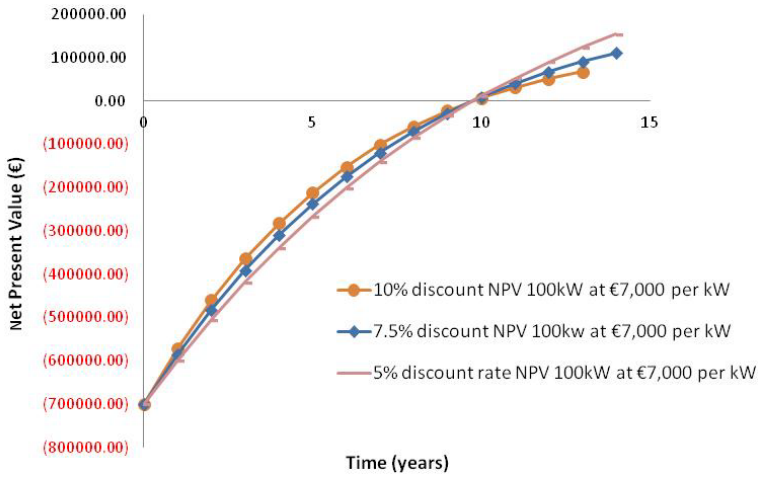

Figure 3.3 – Discount rate comparison for a 100 kW installation at €7,000 per kW.

3.3.4 Flow and turbine efficiency variation analysis

A sample diurnal flow variation for the PRV at Merrion Strand Road in Dublin City is shown in Figure 3.5.

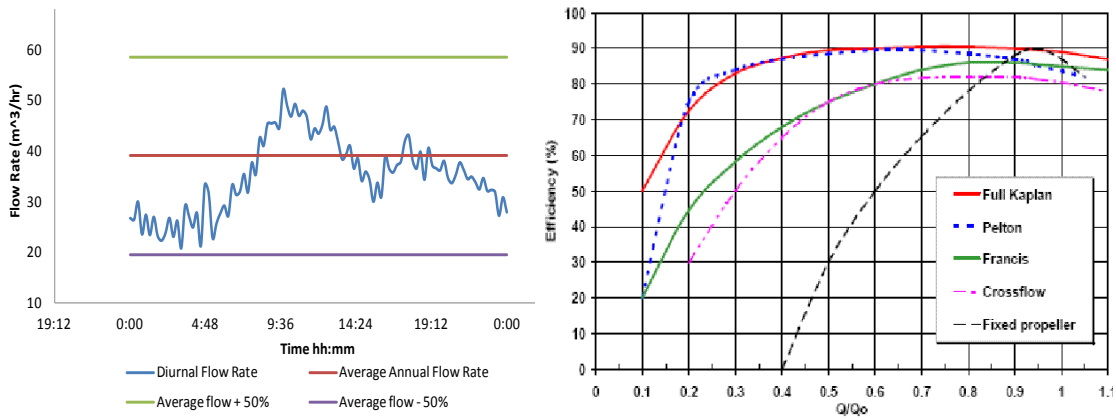

Figure 3.4 – Diurnal water flow variation at Merrion Strand PRV (L); sample turbine efficiency curves (R).

The increase in demand can be seen by the increased flow rates at certain times of the day. These diurnal flow patterns reflect domestic water use and are largely predictable, with a peak in the early morning (high shower use etc.), and again in early evening when people are cooking, cleaning etc. Diurnal variation will also differ depending on the demands in that local area, for example the industrial and commercial mix, water intensive industries, the number of households, sports grounds etc.

The effects of flow variation were assessed in more detail focusing on the 47 kW PRV at Rialto Bridge and the 1 kW PRV at Cardiffsbridge in Dublin city. The annual estimated power generated was compared to the estimated power output using variable turbine efficiencies. The data for these PRVs consisted of a full year from July 2010 to July 2011 of inlet pressure, outlet pressure and flow rate measurements taken every 15 minutes.

Using a constant assumed system efficiency of 65% and using the average annual flow rate and pressure drop, the total annual power generated was calculated (see Table 3.3). The effect of varying turbine efficiency compared to the use of an average efficiency value was then investigated. Turbine efficiency curves as shown in Figure 3.5 were used for a more accurate

estimation of power output and these were incorporated into total system efficiencies. The annual power generated using a Kaplan turbine, Francis turbine and fixed propeller turbine are shown in Table 3.3. The Kaplan turbine was found to be the most efficient over the variation of flow rates present, followed by the Francis turbine.

Table 3.3 – Comparison of turbine types.

Site name	Turbine type	Annual Power Generated (kWh)	Percentage Difference*
Rialto Bridge PRV	Constant Turbine Efficiency	413,403	
	Kaplan	417,925	+1.1%
	Francis	398,919	-3.5%
	Fixed Propeller	356,149	-14%
Cardiffsbridge PRV	Constant Turbine Efficiency	8,812	
	Kaplan	8,644	-2%
	Francis	8,196	-7%
	Fixed Propeller	6,029	-32%

*Percentage differences were calculated between assumed constant turbine efficiency and actual efficiency variations.

3.4 Conclusions and Recommendations

The focus of this section of the project was to investigate the effect of flow variation, turbine efficiency and energy and feed-in tariff variation on MHP project feasibility. The results of the initial analysis show that there is potential for energy recovery in the water supply networks of Ireland and Wales with some estimated power outputs of greater than 100kW. These types of infrastructure locations would be typical of water supply networks in other countries, and, so, the conclusions from this study may find application in other settings.

From the investment payback analysis it was found that the presence of renewable energy incentives such as feed-in tariff schemes has a major effect on the financial viability of small scale hydropower projects. It was also concluded that, for the majority of the cases investigated, the most economic option, where possible, is to use the electricity generated on site, however this was also found to vary across different countries depending on electricity and REFIT prices. It is recommended that governments and legislative bodies consider the introduction or improvement of renewable energy feed-in tariff schemes to incentivise small scale hydropower.

More accurate investment payback periods were calculated using NPV calculations. Other sensitive variables that could affect investment payback are long term changes in water demand, population growth, REFIT tariff changes and the effects of climate change. It is recommended that long term water demand, population and climate data be studied and a further sensitivity analysis (see Section 7), using NPV calculations, be undertaken with these taken into account. This further study would strengthen the investment case through the thorough analysis of longer term, more detailed data.

Turbine selection and turbine efficiency were shown to have a significant effect on the amount of power generated. Using actual flow, pressure and turbine efficiency variations compared with assuming an average value for all 3, showed significant overestimated of power output in some cases. These power overestimations were also larger for smaller scale power plants. It is therefore recommended that variable turbine efficiencies be used for future project feasibility calculations.

Development of an evaluation method for hydropower energy recovery in wastewater treatment plants: case studies in Ireland and Wales

Christine Power[a], Aonghus McNabola[a], Paul Coughlan[b]

[a] Department of Civil, Structural & Environmental Engineering, Trinity College Dublin, Ireland
[b] School of Business, Trinity College Dublin, Ireland

3.5 Introduction

There are two main categories of research investigation carried out to date on hydropower energy recovery in wastewater treatment plants; some studies offer a high-level assessment of the concept with broad ranging estimations of the key technical and economic parameters while other papers deal with specific projects that have been implemented in treatment plants and so the results cannot typically be generalised and applied to other plants. There has been little research carried out on developing an evaluation method to assess the technical and economic viability of hydropower energy recovery at any particular wastewater treatment plant. This paper aims to address this gap; over 100 varying sized plants across Ireland and Wales were investigated for energy recovery potential using a two-tier evaluation method. Firstly, a high level analysis was used to identify the plants with broad energy recovery potential, as determined by the estimated power output and payback period of a hydropower turbine at the plant outlet. Next, a sensitivity analysis was developed to examine the impact on power output and economic viability of a number of key technical and economic variables, including: short and long term flow variations, climate change and population growth, turbine selection, energy price and renewable energy financial incentives.

3.6 Methodology

Flow and head data were collected for 100 wastewater treatment plants (WWTPs) across Ireland. Following an analysis of these data it became clear that smaller-capacity plants, of which there were many in the sample selected for analysis, had limited potential to generate energy savings using hydropower. Only larger plants, typically located in large urban centres, were found to have adequate potential. Subsequently data collected for Wales and the UK focused only on large capacity plants, comprising an additional 11 sites.

3.6.1 Energy recovery potential

The potential hydropower output available at the treatment plant outlets was again calculated according to Equation 3.1. The turbine selection chart shown in Figure 3.5a was used to choose a suitable turbine for the low head and low flow scenario which was most common for all of the plants. Suitable reaction turbine options are the Francis, Propeller and Kaplan turbines. PATs were also considered. The Kaplan turbine was chosen because of its wide efficiency range and suitability for low head and high flow applications.

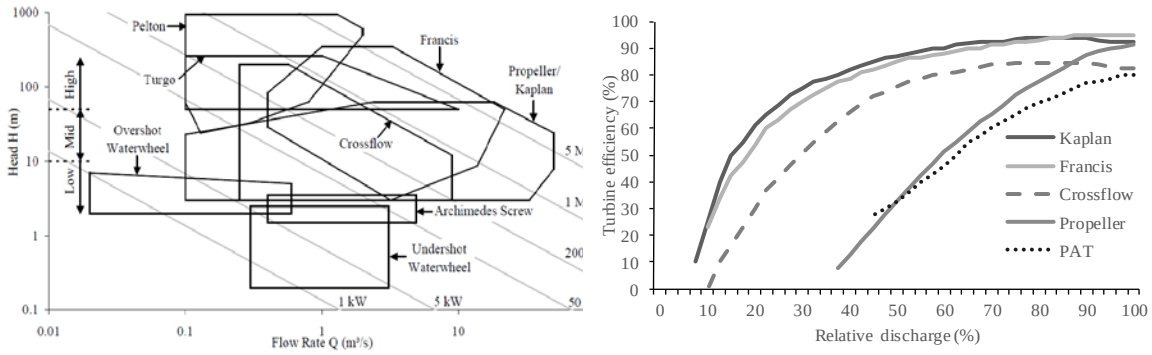

Figure 3.5 – a) Head-flow ranges of MHP turbines as defined by Williamson et al. [58]; b) turbine efficiency curves adapted from Kumar et al. [59].

As can be seen in Figure 3.5b, the maximum efficiency of the Kaplan turbine is approximately 93%. Unlike other hydropower turbines shown, the efficiency of the Kaplan turbine remains quite high for a wide range of flows; the efficiency drops marginally to 90% when the flow through the turbine is only 60% of the design flow [59]. The average efficiency for the Kaplan turbine across the full flow spectrum in Figure 3.5b was found to be 79%. The efficiency of the generator and of electricity transmission over a short range were assumed to be 85% and 98% respectively [60], and so the average plant efficiency was assumed to be 65%. This is in line with the general efficiency range reported for MHP systems, between 60% and 80% [61].

3.6.2 Economic Viability

Based on the potential power outputs estimated for each of the treatment plants, an economic analysis was carried out. Given that cost is a major factor in the success of energy projects, there has been considerable research investigating the cost of hydropower as an energy source. There are many cost-power relationships quoted in the literature; the International Renewable Energy Agency (IRENA) estimates that typical installed costs of MHP schemes are in the range of US$1,300-8,000/kW (€1,000-6,200/kW), while operating and maintenance costs are around 1-4% of the installed costs [62]. A similar estimation of MHP installation costs was made in a British study; £3,000-6,000/kW (€3,700-7,400/kW) [9]. Costs are generally greater for low head sites as larger machines are needed for the higher flow rates [61]. To account for the effect of head on project cost, Aggidis et al. [63] devised two equations based on empirical cost data for various sized hydropower schemes in the UK. Equations 3.3a and 3.3b relate the project cost, C_{pr}, in GBP sterling to the power output, P, (kW) and head, H, (m) for two head categories up to 30 m and greater than 30 m. Building on the cost model used in Section 3.2, these equations were used to estimate project costs for the wastewater treatment outlet MHP installations investigated. A minimum cost of €50,000 was also assumed for all sites.

$$C_{pr} = 25{,}000 \times \left(\frac{P}{H^{0.35}} \right)^{0.65} \quad \text{for heads < 30 m} \qquad (3.3a)$$

$$C_{pr} = 45{,}500 \times \left(\frac{P}{H^{0.3}} \right)^{0.6} \quad \text{for heads > 30 m} \qquad (3.3b)$$

The validity of applying equations 3.3a and 3.3b to wastewater scenarios was also tested using case data from five actual hydropower projects (with a wide range of heads and power capacities) in WWTPs around the world. As can be seen in Table 3.4, the actual installation costs were found to be lower than the estimated costs in three of the five plants. A research paper on the Kiheung Respia plant suggests that the hydropower installation costs were particularly high due to the lack of local relevant infrastructures, such as turbine manufacturers [64]. Therefore, the costs of a similar scheme in a European context may be closer to the estimated costs. With regards to the Deer Island plant in Boston, the projected costs are calculated for a one 1 MW turbine operating at the lowest available head 3.96m. There are in fact two turbines at the plant but the number of turbines is not accounted for in Equation 3.3a. Nonetheless, it is clear that the estimated cost based on one turbine is an underestimated projection of the project cost. This suggests that Equations 3.3a and 3.3b can be used to produce initial conservative cost estimations for hydropower projects at WWTPs. The range of actual costs in Table 3.1 highlights the fact that hydropower projects in a wastewater setting are highly site-specific and so a conservative cost estimate is desirable to account for unexpected additional costs due to the low-head nature of the setting.

As the energy potential at each of the plants was found to be quite low relative to the overall energy requirements of the plants, it was assumed that all of the energy generated would be used on-site. Using the energy on-site also avoids grid connection costs, thus reducing the overall investment. In order to calculate the savings associated with generating energy rather than purchasing electricity from the grid, the end-user electricity price for industrial consumers, €0.096/kWh in Ireland and €0.099/kWh in the UK, were applied to the annual power generation calculated for each plant [65].

The viability of potential hydropower projects was determined according to payback period. Payback was determining according to the European Small Hydropower Association (ESHA) guidelines where *Payback period = (Investment cost)/(net annual revenue)* [66]. For a project to be viable, a payback period of less than 10 years is generally required.

Table 3.4 – Installed hydropower capacity at some actual wastewater treatment plants; Actual installation costs versus costs estimated using Equations 3.3a and 3.3b.

Plant	Installed Year	Head	Power	Actual Cost	Estimated Cost	Estimated - Actual
		(m)	(kW)	(€/kW)	(€/kW)	(€/kW)
La Louve[1] (Switzerland)	2006	180	170	2,529	2,794	265 (+10%)
Nyon[1] (Switzerland)	1993	94	220	2,273	2,825	552 (+24%)
Kiheung Respia[2] (Korea)	2013	4.6	10	10,176	9,600	-576
Point Loma[3] (San Diego, USA)	2001	27.4	1,350	649	1,149	499
Deer Island[4] (Boston, USA)	2001	3.96 - 10.1*	2 X 1,000	2,923	1,982	-941

Technical and economic data for the schemes were obtained from [67][1], [64][2], [68][3] and [69][4]
* The available head at the Deer Island plant outlet varies depending on the tide level.

3.6.3 Sensitivity analysis

Finally, a sensitivity analysis was used to investigate the effects of variations in the key factors that impact project viability, namely:

- flow rate
- turbine type
- financial incentives
- electricity prices

Based on the results from the technical and economic analyses, the WWTP which was found to have the greatest potential for hydropower energy recovery in Ireland was chosen for detailed sensitivity analysis. While the initial analysis was based on an average annual flow rate, daily flow data was analysed for a more realistic evaluation of hydropower potential. In addition, the sensitivity analysis incorporates efficiency variations in the turbine as the flow rate deviates from the turbine design flow rate.

3.7 Results

3.7.1 Energy recovery potential and economic viability

As can be seen in Figure 3.6a, the majority of the plants studied in Ireland had an outflow of less than 0.01 m³/s and only 2.5% had an outflow greater than 1 m³/s.

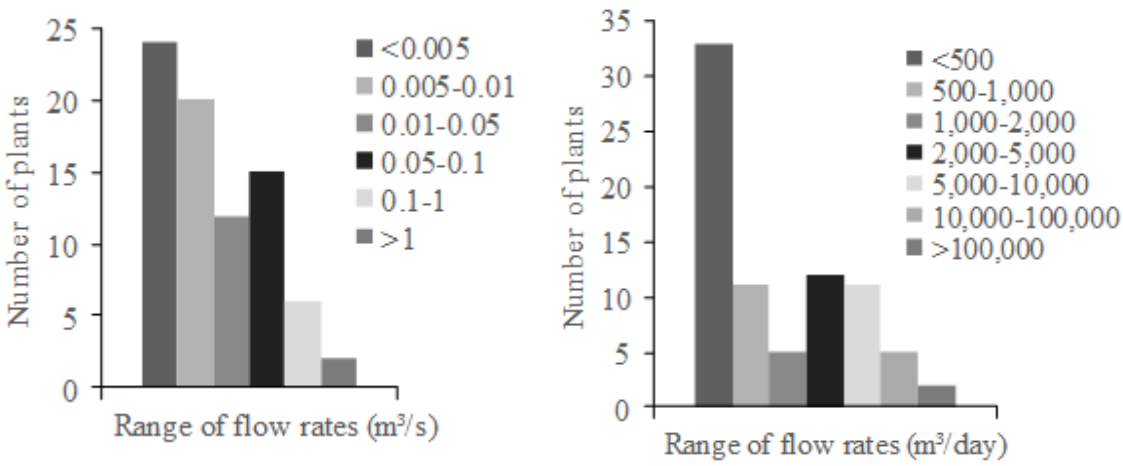

Figure 3.6 – a) number of plants versus flow variation; b) number of plants versus power variation.

Because of the low flow conditions at the majority of the plant outfalls, the potential hydropower output from most plants was negligible, even despite some examples of large elevation drops between the outfall and point of discharge. Figure 3.6b shows the variation in potential hydropower output that was found for the treatment plants studied in Ireland. Most plants had a hydropower potential of less than 1 kW and were deemed unsuitable for energy recovery using hydropower turbines. The low power output for all of these plants was found to be directly

related to low flow rates and head at the plants. The fourteen plants listed in Table 3.5 showed some potential for hydropower energy recovery, having useful power outputs greater than 3 kW.

Table 3.5 – Energy recovery potential and economic viability of the top plants in Ireland.

Plant	Population equivalent	Flow*	Head	Power*	Annual savings	Cost	Payback period
		(m^3/s)	(m)	(kW)	(€/a)	(€)	(years)
Ringsend	1,640,000	4.37	3.7	103.1	86,887	442,128	5.1
Carrigrennan	413,000	1.18	4	30.1	25,368	195,123	7.7
Navan	50,000	0.11	16.3	11.8	9,956	77,175	7.8
Shanganagh	65,000	0.27	5	8.6	7,253	82,187	11.3
Waterford City	190,600	0.37	3.5	8.1	6,866	86,016	12.5
Balbriggan	70,000	0.08	11.5	5.9	4,970	53,188	10.7
Gorey	16,000	0.05	15.2	5.1	4,262	50,000	11.7
Midleton	10,000	0.07	12.5	5.2	4,396	50,000	11.4
Dungarvan	25,000	0.07	10	4.5	3,782	50,000	13.2
Roscrea	26,000	0.04	16	4.6	3,850	50,000	13.0
Limerick City	130,000	0.55	1	3.5	2,973	66,390	22.3
Greystones	40,000	0.09	6	3.5	2,956	50,000	16.9
Tramore	20,000	0.05	9.3	3.1	2,607	50,000	19.2
Michelstown	6,000	0.08	6	3.0	2,538	50,000	19.7
Total output				200	168,664	1,352,209	

*Flow rates presented here are an annual average outflow from the treatment plants, and power outputs are as a result annual average power output estimates.

The results for the UK plants are shown in Table 3.6. Five of the 11 plants with energy recovery potential, are economically viable.

Table 3.6 – Energy recovery potential and economic viability of the top plants in the UK.

Plant	Population equivalent	Flow*	Head	Power*	Annual savings	Cost	Payback period
		(m^3/s)	(m)	(kW)	(€/a)	(€)	(years)
Beckton	3,900,000	14.12	2.6	234.09	202,910	816,241	4.0
Knostrop	1,200,000	4.32	8.5	233.97	202,806	623,214	3.1
Crosness	2,000,000	7.22	4	184.19	159,656	633,257	4.0
Minworth	1,750,000	6.31	4	161.04	139,590	580,315	4.2
Long Reach	836,600	3.00	1.7	32.49	28,162	249,078	8.8
Blackburn Meadows	800,000	2.86	1.4	25.57	22,164	222,796	10.1
Slough	257,000	0.89	1.4	7.97	6,908	104,431	15.1
Reading	284,000	0.99	0.8	5.06	4,386	88,282	20.1
Riverside	552,000	1.96	0.4	5.01	4,343	102,696	23.6
Basingstoke	138,196	0.46	1.1	3.24	2,808	61,456	21.9
Little Marlow	90,000	0.29	1.6	2.92	2,531	52,746	20.8
Total output					777,643	3,584,511	

*Flow rates presented here are an annual average outflow from the treatment plants, and power outputs are as a result annual average power output estimates.

However, only 3 of these can be considered economically viable, having payback periods of less than 10 years. The two largest plants in Ireland, Ringsend (Dublin City) and Carrigrennan (Cork City), were found to have the greatest energy recovery potential, even though the head available at both plants is relatively small. The total hydropower potential for the 14 plants is over 1.75 GWh per annum. This is the power equivalent of 350 households in Ireland, as based on an

average annual electricity usage of 5,000 kWh [70]. Applying the grid emissions factor, 0.52 kg CO_2/kWh [71], an annual carbon dioxide emissions saving of over 900 T CO_2 could be made if a hydropower turbine was installed in all 14 plants.

3.7.2 Sensitivity analysis

The plant with the greatest potential for energy recovery in Ireland, Ringsend (Dublin) was chosen to be examined in greater detail. Data on the variation in flow rates on a daily basis for the year 2011 were obtained to facilitate the in-depth analysis.

Effects of seasonal variation

In general, there is naturally a large seasonal variation in flows arriving at WWTPs. High precipitation levels during the winter months result in increased storm water flows entering treatment plants, thus increasing the overall quantity of wastewater to be treated. In all of the treatment plants studied for this paper, a marked increase in effluent flows was observed during the winter in comparison with summer months. The flow variation for Ringsend (Dublin) in 2011, shown in Figure 3.7, illustrates the typical range of flows. The large flow variations among (and within) seasons affect turbine performance, power output and payback period. There are significant flow variations among months. The lowest average monthly outflow, 3.7 m^3/s, was experienced in August. This was considerably lower than the average outflow for the month of February, 5.9 m^3/s. This variation makes the optimisation of the turbine design flow difficult. The optimisation problem is further complicated by the presence of flow peaks occurring at different times for each month. For instance, if the mode flow (3.57 m^3/s) was chosen as the turbine design flow, it would be exceeded frequently throughout the year, often considerably; the turbine would be under-designed and the energy recovery potential would not be fully realised.

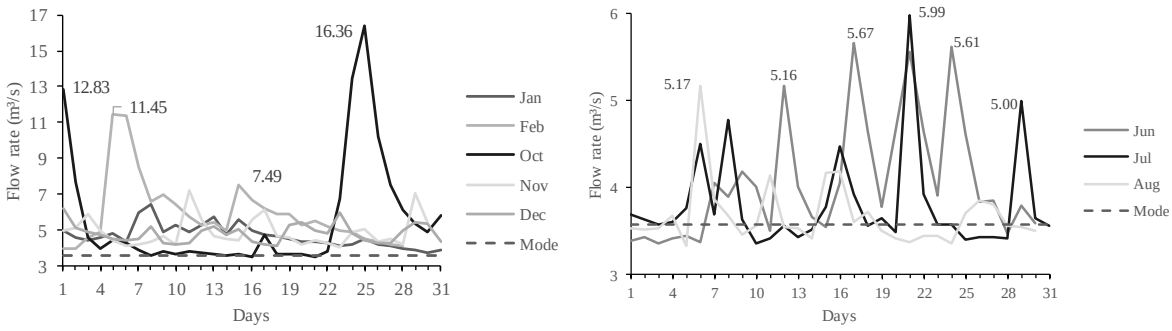

Figure 3.7 – a) Summer flow variation at Ringsend; b) Autumn/Winter flow variation at Ringsend.

A sensitivity analysis was carried out on this flow variation at Ringsend with the aim of finding the optimal design flow to maximise power output. The variation in turbine efficiency with flow rate was included in this analysis and the problem was optimised for maximum energy recovery.

Figure 3.8 is an example of how the daily flow variation was evaluated. In the case of a low design flow, such as 4 m^3/s, the recorded flow rates at Ringsend were at least 80% of the design flow and so the efficiency of the Kaplan turbine only varies slightly (by less than 2%). However, the turbine would be largely under-designed, with flows exceeding the design flow on 173 days in the year. On the other end of the design spectrum, a design flow of 8 m^3/s would only have been reached 7 days of the year and the actual flow rate would have been considerably smaller than the design flow, thus causing the turbine efficiency to drop off. To optimise the power output, where the actual flow recorded for a day exceeded the design flow, the design flow value was used as excess flow that would not be passed through the turbine. Actual flow values were used when the design flow was not reached.

The most optimal design flow for the Kaplan turbine was found to be 5.9 m³/s as this yielded the greatest power output, 1.023 GWh/a. This flow rate optimises the power potential at peak flows while still catering for lower summer flows. The average power for the year using this flow rate was found to be 116.8 kW. The results for the optimal design flow rate can be compared with the average results for the Ringsend WWTP presented earlier in Section 3.7.1. By applying a constant turbine efficiency and assuming that 100% of the flow can be input to the turbine daily, an average power output of 103 kW (0.903 GWh/a) was estimated for the Ringsend outflow rates. This is almost 12% lower than the optimised value. Because the estimated annual power production was greater using daily flows, the energy savings were also found to increase and the payback period was found to decrease to 4.9 years.

The Kaplan turbine design flow for Ringsend is 1.35 times greater than the average flow for the year. The same method was applied to three other WWTPs with readily-available daily flow data, namely Carrigrennan, Navan and Greystones. A similar relationship between Kaplan turbine design flow and average annual flow was found; the most optimal design flows were greater than the average annual flows by a factor of 1.47, 1.36 and 1.51 for Carrigrennan, Navan and Greystones respectively. In the case of Navan and Greystones, daily flow data was available for two consecutive years. Optimisation of the flow data at both plants resulted in very similar design flows year-on-year (with a discrepancy of less than 0.01 m³/s between consecutive years), suggesting similar yearly flow patterns. The relationship between the turbine design flow and mode flow for the four plants considered is not as consistent. Therefore, to begin an evaluation of the energy recovery potential in WWTPs, an initial approximation of the design flow for a Kaplan turbine can be taken as 1.3-1.5 times the average flow. This method can be applied to other turbine types; the relationship between the average flow at the plant and design flow will vary depending on the efficiency range of the turbine type.

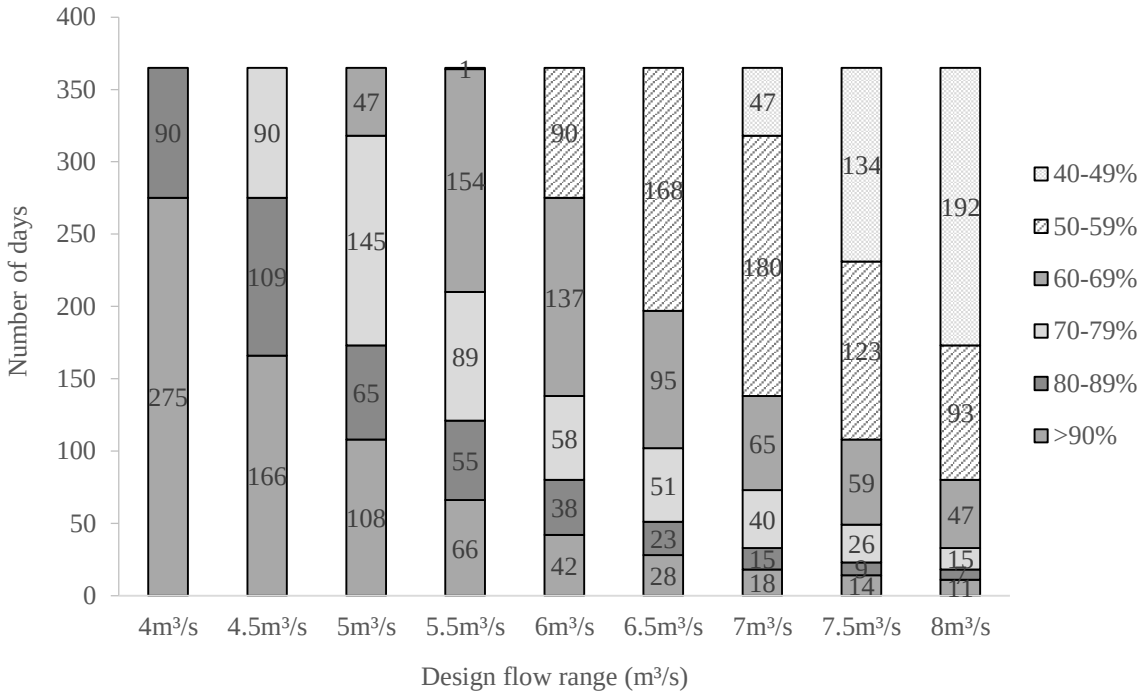

Figure 3.8 – Number of days where actual flow = % design flow.

Long-term flow variation

As well as seasonal variations in flow, the flows from WWTPs can also change in the long term due to economic, industrial and population growth. The population of Ireland is predicted to grow by between 277,000 and 734,000 between 2011 and 2026 [72]. The increase in population will have a direct impact on the flow rates at WWTPs. It is important, therefore, to evaluate not only the

present population and industry loadings but also the future flow rates in the selection of a design flow for a hydropower energy recovery scheme.

Ringsend WWTP was again used to illustrate the impact of demographic changes on potential power output. In the original year-2003 design of the plant at Ringsend, there was roughly a 70:30 split between the expected loading from domestic and non-domestic customers [73]. The current design population equivalent (PE) for Ringsend WWTP is 1.64 million [74]. Extension works are beginning to increase the design PE to 2.4 million by 2016 [75]. The current daily flows were scaled up to the match the 2016 PE, as well as to match predicted PE loadings for 2042. The 2042 flow prediction scenarios modelled high and low PE growth rates at Ringsend as well as the impact of the potential Greater Dublin Drainage (GDD) project which proposes to divert some 600,000 PE of the Ringsend loading to a new regional WWTP [75]. The procedure from the previous section was used to investigate three design flow scenarios, based on the 2016 and 2042 flow estimations, and the payback periods of the scenarios were estimated. The first scenario, shown in Table 3.7a, evaluates the future power potential of a hydropower turbine with an optimal design flow for the current loading at the plant, 5.92 m³/s (as determined in the previous section).

Table 3.7 – a) power projections based on most optimal design flow for 2011 PE.

Year	PE	Design flow (m³/s)	Average power (kW)	Payback period (years)	No. of days flow > design
2011	1.64m	5.92	116.8	4.88	26
2016	2.4m	5.92	157.1	4.40	167
2042^{high}	2.9m	5.92	164.9	4.32	361
2042^{low}	2.6m	5.92	162	4.35	236
$2042^{GDD\ high}$	2.3m	5.92	153.7	4.43	139
$2042^{GDD\ low}$	2m	5.92	139.7	4.58	77

The second case, shown in Table 3.7b, investigates the effect of using a larger turbine, designed for the highest 2042 PE projection, on power output for the range of lower PE loadings. Finally, Table 3.7c shows the ideal scenario whereby the optimal design flow is chosen for each PE loading to achieve the maximum power output.

Table 3.7 – b) power projections based on most optimal design flow for 2042^{high} PE.

Year	PE	Design flow (m³/s)	Average power (kW)	Payback period (years)
2011	1.64m	10.35	108	5.01
2016	2.4m	10.35	169.2	4.28
2042^{high}	2.9m	10.35	207	4.00
2042^{low}	2.6m	10.35	184.5	4.16
$2042^{GDD\ high}$	2.3m	10.35	161.4	4.36
$2042^{GDD\ low}$	2m	10.35	137.2	4.61

Table 3.7 – c) ideal power projections based on most optimal design flow for each PE projection.

Year	PE	Design flow (m³/s)	Average power (kW)	Payback period (years)
2011	1.64m	5.92	116.8	4.88
2016	2.4m	8.61	171	4.27
2042^{high}	2.9m	10.35	207	4.00
2042^{low}	2.6m	9.36	185.2	4.15
$2042^{GDD\ high}$	2.3m	8.25	163.8	4.33
$2042^{GDD\ low}$	2m	7.18	142.5	4.55

Climate change
Changes in climate will also have an effect on the long term flow patterns of WWTPs. Precipitation measurements for the UK have shown an upward trend since 1904, with the greatest increase occurring between 1970 and 1990 [76]. An increase in precipitation causes a rise in the quantity of stormwater to be treated at WWTPs, and thus an increased potential for hydropower energy recovery at plant outfalls. With regards future projections of precipitation, there is a strong contrast across Europe, with large increases in precipitation being projected for the north of Europe and large decreases for the south [77]. There are also seasonal differences in the precipitation projections. Winter precipitation in Ireland is likely to increase by around 3% by the 2020's, while summer precipitation is expected to decrease by around 3% [78]. The summer reductions in precipitation are likely to be greatest along the southern and eastern coasts, where the Ringsend WWTP is situated; reductions of 10-16% are suggested [78]. Global Climate Models forecast this trend to continue on to the 2050's, with winter precipitation in Ireland projected to increase by 10% [78]. Reductions in summer precipitation of 20-28% by the 2050's and of 30-40% by the 2080's are projected for the southern and eastern coasts [78]. Changes in the frequency of extreme events are also predicted, with more prolonged winter rainfall events and more intense summer downpours [78]. These expected changes in the climate will make flow rates at WWTPs less predictable, thus threatening the accuracy of design flow choices for hydro turbines. In particular, the expected increase in extreme rainfall events will increase the variability of flow rates at treatment plants.

Daily precipitation data for 2011 was obtained for Dublin and compared with the recorded flow rates at Ringsend WWTP. A close correlation between rainfall and flow rate was observed, with nearly half of the top 10% of flow rates occurring on days with exceptionally high precipitation (>5 mm). The projected climate changes for Ireland by the 2050's were adapted to the 2011 precipitation data for Dublin; the winter rainfall was increased by 10% and the summer rainfall reduced by 20%. The resulting change in annual precipitation is quite small, (approximately 11 mm), suggesting that annual flow rate changes at Ringsend due to rainfall will be low. However, it is the extreme rainfall events that cause problems in choosing the design flow for turbines. Climate models for Ireland suggest that extreme rainfall events will become more frequent in the future, both in winter and in summer [79]. Because extreme rainfall events cause short-lived peaks in wastewater flows, it is impractical to design a turbine to cater for large spikes in flow. However, a second turbine in parallel with the main turbine could be deployed in periods of high rainfall to exploit the excess flows.

Variation of turbine efficiency with turbine type
The impact of turbine selection on power output was assessed using the Ringsend WWTP as a reference. The turbines considered in this assessment were the Kaplan, Francis, Propeller and PAT. The efficiencies of these turbines were taken from turbine efficiency curves at flow rate intervals of 2.5% (where flow rate is expressed as a percentage of the design flow rate) [59]. These turbine efficiencies were factored by 0.833 to account for generation and transmission losses and to determine thus overall plant efficiency [60]. The most optimal design flow rate to achieve the greatest power output was found for each turbine type. The costs of the turbines were estimated using the cost-power-head relationships reported by Ogayar et al. [80], while a unitary cost estimate of €350/kW was used for the PAT [28]. The results of the optimisation are shown in Table 3.8.

3.7.3 Variation in pricing
The cost of energy is a key factor in the viability of hydropower generation at the outlets of WWTPs. The revenue model used here assumes that all of the energy generated is used directly on-site and so the investment costs are offset by the economic savings associated with generating rather than purchasing electricity. Therefore, hydropower generation at treatment works becomes more economically attractive as energy prices and associated taxes increase. Electricity costs to industry vary across Europe from €0.063/kWh (Bulgaria) to €0.17/kWh (Cyprus) [65]. The

EU-28 average cost of electricity is €0.1/kWh [65]. Using Ringsend WWTP as a reference, the average payback period for the 27 countries is 5.17 years. The low electricity costs in Bulgaria mean that energy recovery is less viable; Bulgaria has the highest payback period for Ringsend, 7.74 years. Conversely because electricity costs are so high in Cyprus, the Ringsend scheme would pay back in only 2.9 years.

Table 3.8 – Optimised design flows, power outputs and costs for 4 turbine types at the Ringsend outlet.

Turbine type	Design flow (m^3/s)	Average power (kW)	Annual power (kWh)	Turbine cost* (€)	Cost*/kW (€/kW)
Kaplan	5.9	116.8	1,022,853	$31{,}196.P^{0.42}.H^{-0.11}$	1,673
Francis	5.4	115.9	1,014,806	$25{,}698.P^{0.44}.H^{-0.18}$	1,519
Crossflow	5.8	104.7	916,904		
Propeller	4.2	102.3	896,041	$19{,}498.P^{0.42}.H^{-0.11}$	1,130
Pump as Turbine	4.3	90	787,789	350.P	350

* Costs calculated here are for the turbines only, using [28, 80].

As well as regional variation in electricity prices, it is also important to take future energy prices into account. As fossil fuel resources are declining, energy costs are increasing. An example of this is oil prices which increased from $US 29 billion in year-2004 to $US 151 billion in year-2008 [81]. Coal and natural gas prices have followed a similar upward trend [81]. The International Energy Agency predicts that the average price of electricity for households in the OECD will increase from $0.14/kWh in 2011 to $0.24/kWh in 2035 [82]. As energy prices increase, the economic viability of installing hydropower turbines at the outlets of WWTPs improves. Current data as well as future forecasting for the energy market in Ireland were obtained from Sustainable Energy Authority of Ireland (SEAI). The electricity fuel mix in 2011 was compared with year-2020 projections and fuel costs (both current and forecasted 2020 costs) were used to estimate the future change in electricity prices in Ireland. Using the most recent statistical data from SEAI, two scenarios were considered for the year-2020 electricity fuel mix. The baseline scenario includes all policy measures up to the end of 2010 and assumes that no future policy actions will take place, while the NEEAP/NREAP scenario assumes that, in accordance with the National Energy Efficiency Action Plan (NEEAP) and the National Renewable Energy Action Plan (NREAP), Ireland will achieve a 20% saving in energy efficiency and a 16% renewable energy share by 2020 [83]. The mix of fuel input and estimated future fuel costs are combined in Table 3.9. The cost of fuel for renewable electricity (such as wind, solar and hydro) is zero.

Table 3.9 – Fuel mix and cost of electricity in Ireland in 2011 and in Baseline and NEEAP/NREAP 2020 scenarios adapted from [83, 84]

Fuel	Fuel inputs for electricity (ktoe)			Total cost €M		
	2011	2020 Baseline	2020 NEEAP/NREAP	2011	2020 Baseline	2020 NEEAP/NREAP
Coal	913	1120	1002	899	1,205	1,078
Oil	55	0	0	30	-	-
Gas	2500	2384	2062	705	807	698
Peat	480	463	421	60	57	52
Renewables	516	836	1345	-	-	-
Total	4464	4803	4830	1,694	2,070	1,829

Both scenarios in Table 3.9 predict an increase in future fuel costs for electricity. The Baseline scenario predicts a 22.22% increase in fuel costs between 2011 and 2020, while the more optimistic NEEAP/NREAP scenario results in a 7.98% increase. Based on these predictions, the electricity price for industry in Ireland will range from €0.104/kWh (NEEAP/NREAP) to €0.118/kWh (Baseline). These price predictions are conservative in that they ignore rising capital costs for electricity, such as new renewable generators and maintenance of existing generators,

transmission lines and distribution lines. Nonetheless, the figures suggest an upward trend in future electricity prices, thus increasing the economic viability of hydropower energy recovery. The effect of this predicted increase in electricity price on economic viability was investigated for the 14 Irish WWTPs found to have potential for hydropower energy recovery. While four plants show economic potential for energy recovery based on current electricity prices, a further four plants could be economically viable if electricity prices increase according to the Baseline scenario predictions. The 7.98% increase in electricity prices predicted by the NEEAP/NREAP scenario will result in five plants having a potential payback period of less than 10 years.

The effect of renewable energy feed-in tariffs (FITs) on the economic success of hydropower energy recovery was also evaluated. As with electricity pricing, FITs for hydropower vary across Europe. Only 18 of the 28 countries have FITs for hydropower and the rates for hydro are on average the lowest for all renewable energy sources, with many countries choosing to prioritise wind and solar PV. The average FIT rate for hydro amongst the 18 countries is €0.092/kWh, which is low in comparison to that for solar PV in the same 17 countries, €0.358/kWh [65]. Using Ringsend as an exemplar of a WWTP suitable for hydropower energy recovery, the payback period for investment was calculated based on the revenue from the various FIT rates across Europe. The results show that it is more economically viable to use the electricity on-site rather than sell it to the grid in 11 of the 18 countries, including Ireland. Furthermore, there are two countries, Bulgaria and Hungary, which have such low FIT rates for hydro that selling the electricity results in a payback period of greater than 10 years, which is considered the cut-off point for viability in this analysis. The FIT rates in seven of the countries are high enough to result in shorter payback periods than those due to using the electricity on-site; the UK has the highest FIT rate for hydro (€0.23/kWh). It is important to note that the analysis used assumes that the capital cost will be the same whether the electricity is used or sold, whereas in reality the initial costs for grid connection would typically be higher due to additional costs for power cables, transformers and regulating equipment. Also, because hydropower generation in WWTPs is still a relatively new concept with only few working examples globally, there is political uncertainty around whether or not such projects are eligible for FITs due to pumping of the wastewater prior to the hydropower generation. Therefore, given the ready demand for power at WWTPs and the growing price of electricity, using the electricity on-site is most likely more economically viable than selling the electricity to the supply grid.

3.8 Discussion

3.8.1 Energy recovery potential & economic viability

Flow was found to be the most important parameter for hydropower potential at WWTP outlets. Of the 100 plants evaluated in Ireland, only 14 were found to have usable power output (>3 kW). These plants are all relatively large, and the greatest potential was found at Ireland's two biggest plants, Ringsend and Carrigrennan respectively. It is important also to include economic analysis, even in initial evaluations of energy recovery potential. In the findings of this paper, the number of plants in Ireland with potential for energy recovery was reduced further from fourteen to three when economic payback was considered, while the list of potential UK sites dropped from eleven to five.

While head is an important parameter for hydropower generation, it was found to have a small impact on hydropower potential at WWTP outlets. This is because the head available at WWTPs is typically very small, with most plants being designed with low elevations such that gravity flow is achieved. Also treatment plants are mostly located close to or at similar elevations to the receiving water bodies to reduce construction costs for the outlet pipes. The average head for the plant outlets studied in Ireland was 4.4 m. A large flow rate is required for economically viable energy recovery at such low heads. This can be seen by examining the results for the Roscrea treatment plant which has small population equivalent capacity of 26,000. Despite a relatively large head of 16m, the potential power output of a hydropower turbine at the plant outlet is only

4.6 kW, due to the low flows at the plant. Therefore, an evaluation of a number of WWTPs should initially focus on the plants with large flows.
Nonetheless, there are some examples of hydropower energy recovery schemes in operation which exploit large elevation drops between WWTP outlets and discharge points. Therefore, plants in hilly terrain for instance may have sufficient heads to generate usable power output. An example of one such plant in operation is the Nyon plant in Switzerland which was built 110m higher than the lake to which it discharges due to space restrictions [67]. There is a large gross head of 94m available to the turbine, resulting in a 220 kW power output [67]. While natural heads such as this are unusual at WWTP outlets, there may be potential to increase the head available by relocating the final discharge point further downstream in the receiving water body. This is most likely only a viable option for large plants, because smaller plants will require considerable head increases to generate sufficient power with an acceptable return on investment. An in-depth cost benefit analysis is essential to compare the increase in investment costs (due to the additional planning requirements, civil works and pipe costs etc.) with the increased savings in electricity costs due to the additional power output. Also, planning issues with relocating the effluent pipe need to be considered. For instance the most optimal discharge point may be located in a sensitive or restricted area, or the effluent pipe may need to cross private property. The potential for increasing the head is very site-specific and so these cost and planning issues need to be considered for each individual plant. The Seefield Zirl treatment plant in Austria is an example of a plant which successfully increased the outlet head available. The treated effluent is pumped over a hill (at a gross head of 94m) and then flows into a 1,192 kW turbine before entering the Inn River [67]. The hill is quite small relative to the gross head available to the turbine (625 m) and so the electricity generated is large enough to supply both the pump and treatment plant energy demands and excess electricity is sold to the grid [67]. Also the scheme has improved local ecology by discharging the treated effluent into the Inn River rather than to the smaller stream near the plant [67].

3.8.2 Short term flow variations

While average flow rates can be used as an initial approximation of power output to identify sites with energy recovery potential, historical flow rate records should be analysed for a more refined estimation of potential power. Flow rates at WWTPs typically vary throughout the year, due to seasonal variations in precipitation. It is important to choose the optimal design flow that will capture the base flow at the plant while not compromising on the peak winter flows so to deliver the greatest annual power output. As flow variations may change annually, studying data from as many years as is possible will improve the accuracy of the design flow optimisation. The importance of choosing the most suitable design flow rate can be seen in the case of the hydropower scheme at the Profray WWTP in Switzerland. The hydropower plant was initially designed for a flow of 0.24 m^3/s to take into account storms and snow melting and the marked population increase at the ski resort during the winter months [85]. These conditions were not typical throughout the year and so the turbine was only working at its nominal discharge for a few days per year [85]. A new turbine was designed for 0.1 m^3/s, resulting in an increase in electricity production of 45%, even though the nominal discharge was 2.4 times lower [85].

Ringsend WWTP was used to demonstrate the impact of seasonal flow variation on potential hydropower output using a Kaplan turbine. A design flow 1.35 times the average flow at the plant during 2011 was found to have the greatest power output; this turbine design exploited the larger winter flow rates while not impeding on turbine efficiency for the partial base flows. The design flow is higher than the average flow due to the presence of peak flows caused by extreme rainfall events. The same method was applied to three other plants with daily flow data and the most optimal design flow was found to be 1.36-1.51 times the average annual flow at the plants. The higher ratio between design flow and average flow at these plants may be explained by lower flow peaks, allowing a marginally increased design flow to capture more of the extreme events. For instance, in the case of the smaller Greystones plant, the average flow rate is 46-51% of the maximum daily flow recorded at the plant in 2010 and 2011 respectively, while at Ringsend the

average flow is only 27% of the maximum flow for 2011. Therefore, because the flow peaks at Ringsend are greater, it is not possible to capture all of the higher flows without compromising on efficiency for the lower average flows and so the most optimal design flow is relatively lower; but at Greystones there is less deviation from the average flow so a higher design flow is possible.

3.8.3 Long term flow variation (population, climate, economy)

The main causes of long term flow variation at WWTPs are demographic, economic and climate changes. A WWTP is designed according to the population equivalent (PE) of its catchment area, whereby the PE is the contribution of population (both living in the area and commuting to the area), tourism, industry and other such generators of sewage to be treated. Therefore when projecting future flow rates at treatment plants it is important to consider planned developments for industry, tourism, services (such as hospitals and schools) and other contributing areas as well as predicted population trends. It is also crucial to account for the percentage split of the various components of the population equivalent and to estimate this split in the future. Census data, development plans and predicted growth rates for an area will help determine this.

Flow rate data for Ringsend, both current and future predictions, were used to illustrate the effect of long term flow changes. Three design flow scenarios were investigated and it was shown that for a high performing turbine, such as the Kaplan turbine, it is better to over-design the turbine to allow for future growth than to under-design it. Because prediction models suggest an increase in future PE loading at Ringsend, if a hydropower turbine was designed according to current flows at the plant, it would be largely under-designed for future flow rates. Based on the highest PE projection for 2042, the predicted flow rates at the plant would exceed the 2011 design flow 361 days in the year and the estimated power output is 20% lower than the potential power output of a turbine designed for the high 2042 flows. As a result, the economic payback period is longer. Conversely, when the turbine was optimised according to the highest 2042 flow predictions, a higher design flow (10.35 m^3/s) is selected, allowing for more of the larger future flows to be exploited. Higher power outputs and lower payback periods were found for all of the predicted future flows when compared with a turbine designed for 2011 flows. Because the Kaplan turbine performs well at low flow rates, the power output achieved deviates only slightly from the maximum and the payback period increases marginally from 4.88 to 5.01 years. Of all the flow scenarios investigated, the turbine designed for the highest 2042 PE projections has the greatest energy recovery potential and is the most economically viable.

This paper proposes an evaluation method for hydropower energy recovery in WWTPs. A technical and economic feasibility assessment is used to identify plants with potential for generating a usable power output within an acceptable payback period. This evaluation of over 100 plants in Ireland and the UK found that only large plants with high flow rates are suitable for hydropower energy recovery. Having identified suitable sites, a sensitivity analysis is then used to evaluate the hydropower potential in further detail. Flow variation, turbine selection and electricity pricing are investigated in this analysis to optimise turbine design flow rate, maximise power output and minimise economic payback period.

Flow variation, both in the short term and in the long term (due to demographic and climate changes) was found to have a large impact on turbine selection and on turbine efficiency. There is scope for further study using data from a longer time period to compare annual flow trends and assess the impact on the design flow. While the evaluation method was illustrated for Ringsend using data from one year, the addition of data from other years allows for a more reliable choice of design flow. Also the relationship between turbine design flow and average outlet flow should be further explored to include WWTPs located in areas with different climatic and demographic features. Plants of interest for such study might include those in countries which experience monsoon rainfall seasons or those in urban areas which have largely varying seasonal populations, such as tourist towns which might experience a summer increase in population and university towns which might have a summer decrease. Due to the potentially larger seasonal variation in

flow in such plants, the possibility of two turbines should also be explored. There is also scope for future study on tidal outfalls, which may benefit from increased power output due to varying head conditions.

3.8.4 Turbine selection

The impact of turbine selection on power output was illustrated for Ringsend WWTP. The optimal turbine choice in terms of power output was the Kaplan turbine, followed by the Francis. This was to be expected as both turbines have a high efficiency over a long range of flows. In contrast, the Propeller turbine (which has fixed guide vanes) performs poorly when the flow drops below the design flow rate. The optimal design flow for the propeller turbine (4.2 m^3/s) is therefore lower to cater for the lower summer flow rates, and so the peak flows during wet months are not exploited to the full. Based on 2011 flows at Ringsend, the Propeller design flow would have been exceeded on 139 days in the year and because of this, over 19 million m^3 (14% of the total flow for 2011) would have bypassed the turbine. However, the Propeller was found to be most economically viable of the three turbine types, having the lowest cost per kilowatt. This finding illustrates the importance of including economic as well as technical analysis in the evaluation of energy recovery.

Overall, the PAT had the lowest cost, of the order of 5 times cheaper than the turbine types. This is in line with other studies which report that PATs are cheaper because (unlike turbines) pumps are mass produced around the world [22, 86]. Given the considerably lower cost of the PAT, there may be potential to use multiple pumps in parallel to capture the large flows at the plant. There are limitations to these results, however. The pumps required for such power outputs are very large and are likely to need industrial modifications for reverse flow for use as a turbine. These costs have not been considered in the analysis. While the PAT had the lowest cost, it also resulted in the lowest power output. To improve the power output, the PAT could be regulated, either hydraulically or electrically, to stabilise the efficiency during flow and head variations [27]. In enabling the PAT to operate close to its best efficiency point, the use of regulation will also increase plant reliability and reduce maintenance costs. A cost-benefit analysis should be used to determine if the additional cost for PAT regulation is justified by the increased power output and improved plant reliability [87].

3.8.5 Energy price & FITs

Analysis of feed-in-tariff rates across Europe show that it is more economically viable to use the electricity generated on-site at the WWTP than to sell the electricity to the grid in the majority of the EU countries investigated, including Ireland. The economic viability of using the electricity onsite improves as electricity prices increase (as witnessed in recent years and as predicted for the future). Analysis of the prediction models available for Irish electricity prices showed that the economic viability of energy recovery will most likely improve in the future as electricity usage and electricity fuel input costs increase. While hydropower energy recovery was found to be economically viable at three plants in Ireland based on current electricity prices, a further 1-4 plants could be viable by 2020 based on future electricity price predictions. With regards regional variation, Irish electricity prices are currently near the EU average; countries with higher electricity prices, such as Cyprus and Malta, have shorter payback periods since the avoided energy cost through hydropower energy recovery is higher.

3.8.6 Evaluation method

The evaluation method developed in this study is shown in Figure 3.9. Evaluation of hydropower energy recovery is based on estimates of power output and payback period. The initial step in the method is useful in narrowing down a selection of sites to those most suited to energy recovery. However, as average flow and turbine efficiency are used, the estimates of power output and resulting costs are crude and the second step is essential in obtaining a more accurate evaluation of energy recovery potential.

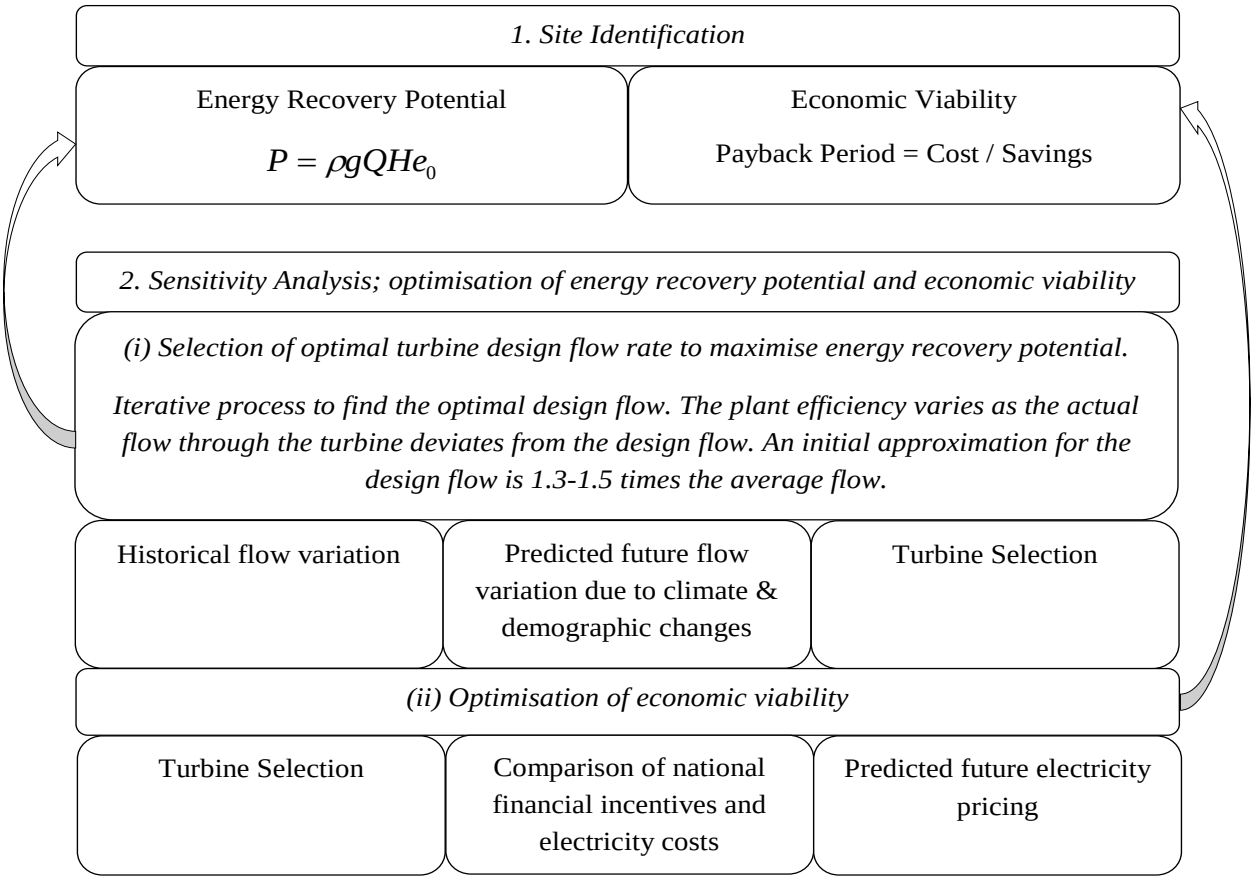

Figure 3.9 – Evaluation method for hydropower energy recovery in WWTPs.

The method developed focuses on the optimisation of turbine design and economic payback period. The method could be improved by including the optimisation of head; this would require a cost-benefit analysis of the relocation of the outfall point to a lower elevation. There is particular potential for head optimisation for new WWTPs, which could be designed to incorporate hydropower energy recovery. The variation in head loss with flow rate should also be considered. As illustrated by Griffin [39], this involves determining the head loss due to friction for hourly flows (if available) and thereby adjusting the available net head. With regards to the economic analysis, the use of payback period alone is a limitation of the evaluation method; the Net Present Value method could also be used [66]. Furthermore, the analysis was based on capital costs; operating and maintenance costs should be included for a more accurate evaluation of economic viability.

3.9 Conclusion

This paper proposes an evaluation method for hydropower energy recovery in WWTPs. A technical and economic feasibility assessment is used to identify plants with potential for generating a usable power output within an acceptable payback period. This evaluation of over 100 plants in Ireland and the UK found that only large plants with high flow rates are suitable for hydropower energy recovery. Having identified suitable sites, a sensitivity analysis is then used to evaluate the hydropower potential in further detail. Flow variation, turbine selection and electricity pricing are investigated in this analysis to optimise turbine design flow rate, maximise power output and minimise economic payback period.

Flow variation, both in the short term and in the long term (due to demographic and climate changes) was found to have a large impact on turbine selection and on turbine efficiency. There is scope for further study using data from a longer time period to compare annual flow trends and

assess the impact on the design flow. While the evaluation method was illustrated for Ringsend using data from one year, the addition of data from other years allows for a more reliable choice of design flow. Also the relationship between turbine design flow and average outlet flow should be further explored to include WWTPs located in areas with different climatic and demographic features. Plants of interest for such study might include those in countries which experience monsoon rainfall seasons or those in urban areas which have largely varying seasonal populations, such as tourist towns which might experience a summer increase in population and university towns which might have a summer decrease. Due to the potentially larger seasonal variation in flow in such plants, the possibility of two turbines should also be explored. There is also scope for future study on tidal outfalls, which may benefit from increased power output due to varying head conditions.

4. GIS

A strategic assessment of micro-hydropower in the UK and Irish water industry: identifying technical and economic constraints

J. Gallagher[a], I.M. Harris[a], A.J. Packwood[a], A. McNabola[b], A.P. Williams[a]

[a] School of the Environment, Natural Resources and Geography, Bangor University, Wales
[b] Dept of Civil, Structural & Environmental Engineering, Trinity College Dublin, Ireland

4.1 Introduction

A geodatabase was created to facilitate the assessment of potential energy recovery sites in regions of the UK and Ireland. The structured four-step methodology developed would help water companies to only consider the most suitable sites to implement micro-hydropower (MHP) within their infrastructure and to prioritise investment in those sites with greatest potential returns. In addition to existing MHP turbines, previously unpublished data on a purpose built pressure control (PC) MHP turbine system was considered as part of the technical and economic assessment for energy recovery in water infrastructure.

4.2 Methods

4.2.1 Energy recovery in the water industry

Study area

The study area used to conduct this investigation combined regions of Wales and Ireland as defined by the Hydro-BPT project (www.Hydro-BPT.eu). This took into account the majority of counties in the east and south of Ireland and some of the major cities in Ireland. The majority of the country was included in the study in Wales as Dŵr Cymru / Welsh Water managed the majority of water infrastructure.

Calculating potential energy

To quantify the potential energy recovery with the installation of the MHP turbines at each of the sites, the estimated power output was calculated using Equation 4.1.

$$P = Q\rho g H e_o \qquad (4.1)$$

Where P = power output (Kw); Q = flow rate through the turbine (m^3/s); ρ = fluid density (kg/m^3); g = acceleration due to gravity (9.81 m/s^2); H = head available at the turbine (m); e_o = overall efficiency of the system (estimated at 65%, similar to that used by previous study [35]).

Economic payback of MHP turbine and generator

An acceptable payback period is currently the primary driver for a MHP installation. The cost of the turbine and generator can be estimated based on flow conditions for each site, and are considered as the most expensive components of a MHP installation. The costs of variable flow and pressure control (PC) turbine/generator units that are designed for water infrastructure were used [88]. Unlike other current turbines, the PC turbine provides a suitable replacement for a PRV in water distribution networks. Costs for Pelton, Francis and Kaplan turbines and generator units were calculated based on previous research by Ogayar and Vidal [89] and are shown in Equation. 4.2 and Table 4.4. In this case, the equations were updated for MHP installations as projects greater than 300 Kw were omitted from the dataset to develop the equations. In addition, inflation since 2008 (year of original data collation) was accounted for, to provide more accurate costs in 2014. The economic payback was calculated using Equation. 4.3.

$$T = a.P^b.H^c \qquad (4.2)$$

$$E = {}^{T}/_{(p \times i)} \qquad (4.3)$$

Where T = cost of turbine and generator (€); P = power (Kw); H = head (m); E = annual electricity generated (kWh); a = constant (2008 to 2014 inflation rate of 1.15005 in Table 4.4 [90]); b and c = co-efficient for power and head, respectively (Table 4.4); E = economic payback for turbine and generator (years); p = total power output over one year (kWh); i = income from FITs (€/kWh).

The equations provided a reasonably accurate estimate of the turbine and generator costs and payback within a range of ±12% for the PC turbine, ±20% for the Pelton and Francis turbines and ±30% for the Kaplan turbines. The lack of lower scale MHP data that was used to generate the equation for the Francis turbine costs (n = 6, sites 80-300 Kw) led to this turbine not being considered in the economic assessment for this study.

Table 4.4 – Coefficients for calculating turbine/generator costs adapted from previous studies [88, 89].

Turbine	a		b	c	Equation		
	'08	'14*			n	Kw range	R^2
PC turbine	-	37,792[1]	0.531	-0.119	13	11-30	0.94
Pelton	6,361	7,316[2]	0.698	-0.114	13	25-300	0.98
Francis	131	150[2]	1.309	0.028	6	80-300	0.98
Kaplan	19,264	22,155[2]	0.440	-0.152	23	9-300	0.98

* It is assumed turbine/generator fixed price across Europe (unlike the other project costs e.g. installation)
[1] Based on 2014 UK pricing list and changed to Euro rate.
[2] Calculated based on 2014 Euro Spanish inflation rate since 2009 for turbines installed in Spain.

4.2.2 GIS database and mapping resources

For the GIS database, the European Terrestrial Reference System (ETRS89) was used as it is the EU-recommended frame of reference for geodata for Europe [91]. The geodatabase allowed for a spatial and temporal examination of site characteristics and allowed for a comparison of energy recovery and project cost data. The database provided the key variables: site type (e.g. BPT or PRV); coordinates (longitude and latitude, ETRS89 grid); site information (place name, county and country); daily site flow characteristics (mean pressure head (m) and flow (l/s)); the energy recovery (Kw); population statistics; economic costs; other relevant site classification details (e.g. nearest grid location). Water infrastructure data were collected from over 10 local authorities in Ireland and Dŵr Cymru Welsh Water in Wales. The quantity and quality of data provided varied significantly but included the location and type of all energy recovery sites and a measure of the pressure and flow characteristics.

Population and boundary data were sourced from the *Central Statistics Office* in Ireland [92-94] and the *Office for National Statistics* in the UK [95-97], with reference data accessed through *Eurostat*, the European Commission statistics database [98, 99]. To overcome problems associated with combining different national census geographies, an approach outlined by the European Forum for GeoStatistics [98] to produce 1 km population grid data was followed, using the baseline 2006 grid as a reference year. The national and European statistics bodies provided census data for 2011 and similar population grids were produced. Sites were then classified as remote, rural or urban, based on European definitions (≥300 people per km^2 is an urban area) [41]. Sites were also classified as residential, domestic or industrial using a visual examination process. All sites were categorised based on the predominant land use (e.g. housing estates, pasture or industrial area) within the vicinity of each MHP installation. This was undertaken using Bing Maps and Google seamless orthophoto backdrops via the Arc2Earth extension within ArcGIS (ESRI, 2009-2013) [100].

4.2.3 Feasibility process for examining MHP sites

Energy recovery is dependent on the characteristics of sites that were collated and input to the geodatabase. From previous findings, the energy recovery potential for most sites in water infrastructure in regions of Wales and Ireland ranged from 1-25 Kw [101]. The economic feasibility for implementing MHP becomes more challenging as the capacity for generating electricity is reduced. The feasibility of MHP sites is also affected by the technical challenges presented by different sites characteristics. Figure 4.6 displays the four-step methodology adopted for this study to assess the technical and economic challenges of a MHP installation in water infrastructure.

This strategic approach outlined in Figure 4.6 considers only the most suitable sites by examining energy recovery potential (Step 2) and examining the technical and economic constraints for each MHP installation (Step 3). The first stage (Step 1) outlined the types of site that exist in water and wastewater infrastructure for energy recovery: SRVs, BPTs, PRVs and WWTPs. Following this, local infrastructure was examined at each MHP site to identify the technical challenges of implementing MHP.

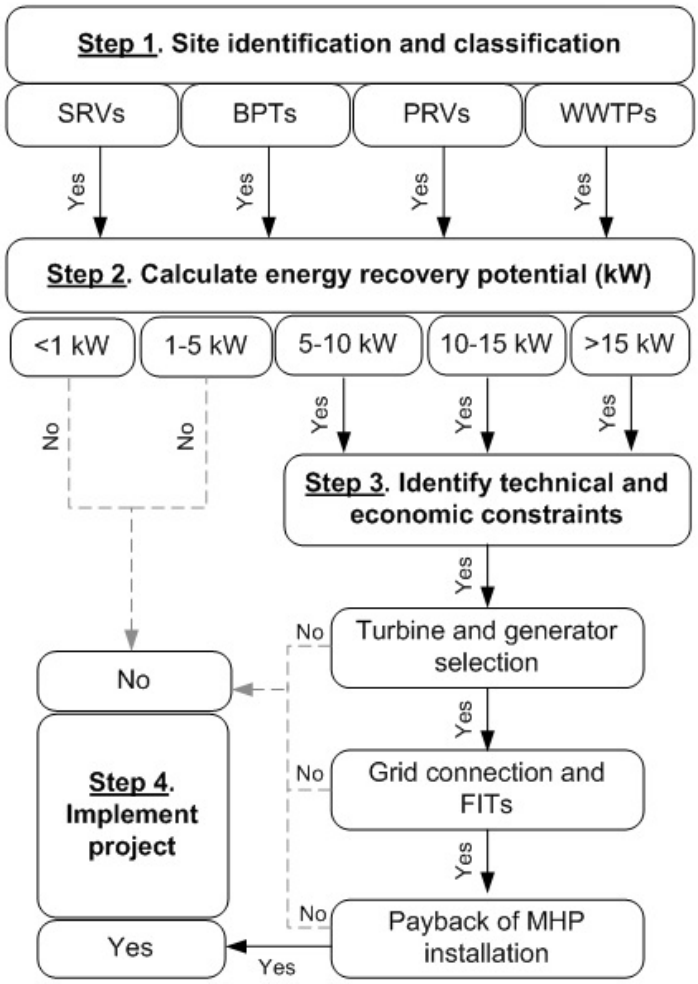

Figure 4.5 – Four-step methodology for selecting a feasible MHP site in water or wastewater infrastructure.

The shortlisted sites were considered based on an estimation of energy recovery at each site. The technical and economic constraints were explored for shortlisted sites and included assessing grid connection and FIT, turbine selection and economic payback. The cost of the turbine/generator unit for each site provides an initial estimate for the primary components required for energy recovery. Based on this, the additional project costs were estimated based on local site characteristics to determine the economic feasibility of the shortlisted sites.

Step 1. Site identification and classification

Site categorisation was based on (i) local population grid densities and (ii) a visual examination of each site. This was to strengthen the spatial and temporal analysis and enhance details relating to site classification in the geodatabase. It provides evidence for water companies to assess energy recovery at each type of site and supports other technical and economic decisions for developing a MHP project.

Step 2. Calculate energy recovery potential

The energy recovery potential for each site was calculated based on 2011 average flow and pressure data using Equation 4.1. Sites were grouped based on the estimated energy recovery. These groupings were created to determine the number of sites on the lower and higher ends of the energy recovery spectrum. Based on previous literature, sites less than 5 Kw (and in some cases <10 Kw) were considered too small to be economically viable for implementing MHP technology [102, 103]. Furthermore, sites larger than >15 Kw were grouped together as they were classified at a different FIT capacity band, thus the economic payback was different between these and the smaller sites.

Step 3. Identify technical and economic constraints
Each installation can have a range of variable components: the turbine/generator, civil works, electricity grid connection and other ancillary or consultancy costs. The technical constraints of the remaining sites were examined and the geodatabase was used to estimate the costs associated with the selection of a suitable MHP turbine and generator.

The selection of a suitable turbine and generator is dependent on having an understanding of historical demands at each MHP site. Flow and pressure characteristics in pipes can be difficult to predict due to the diurnal, weekly and seasonal variations in water supply and wastewater collection. This provided a number of challenges relating to turbine design and costing, as it would affect long-term efficiencies and the energy recovery at each site. Flow variations are also influenced by external strategies implemented to reduce water demand, such as smart metering, leakage control and behavioural change [104]. Historical flow and pressure data were examined for a subset of PRV sites as they represented the most economically sensitive sites. The analysis provided a better understanding of the level of robustness required for each MHP installation. The flow data used to develop the turbine cost equations was also used to select the most suitable turbine at each site.

Step 4. Implement project
This step will define what sites are feasible based on the previous findings and summarise the requirements for MHP projects to be successfully implemented.

4.3 Results & discussion

4.3.1 Step 1. Site identification and classification

Based on site classification, some assumptions can be made relating to local infrastructure. However, an evidence base to justify these assumptions can provide a clearer picture for the true potential of these MHP installations. A number of factors were considered in Table 4.5 to highlight the technical challenges for installing MHP at water and wastewater infrastructure sites.

Table 4.5 – Identifying local infrastructure at MHP sites in water and wastewater networks.

Site type	Considerations
SRV	Storage reservoirs typically feed into water treatment works, while service reservoirs can store treated water. The availability of an electricity grid connection depends on the type of reservoir. These sites typically have high flows and/or pressure heads, therefore good turbine efficiencies can be achieved to maximise energy recovery. Electricity generated from a storage reservoir can be used directly by the water treatment works that they feed. In addition, these energy recovery sites are likely to be the only locations where FITs are applicable.
PRV	PRVs are located throughout the water distribution network and the availability of a suitable electricity grid connection will therefore vary significantly. Site infrastructure for PRVs typically consists of a chamber which varied in size and the need for additional civil works depended on the specific dimensions of a chamber. The electricity generated at PRV sites is restricted by the diurnal changes in flow and the limited allowance for MHP turbines to extract only excess energy in the system.
WWTP	As WWTPs require electricity to power operations, a suitable grid connection at each site is likely. Electricity can optionally be used on site. Robust turbine design and suitable screening is required prior to treatment for energy recovery from raw sewage. Low head presents more notable challenges for electricity generation as a more robust turbine design is required for MHP installations at both inlet and outlet points of WWTPs. In some cases, treatment outflows present variable flows for outlets located in tidal zones, which requires pumping and significantly limits energy recovery.

From the findings outlined in Table 4.5, the technical challenges presented are unique for each type of site. The availability of an electricity grid connection at energy recovery sites was a common constraint. Two methods of analysis were considered to determine the proximity of a suitable grid connection: (i) 1 km population grid densities to classify sites as remote, rural or urban and (ii) a visual inspection to determine if a site was in an agricultural (A), domestic (D) or industrial (I) area. This exercise strengthened the spatial and temporal analysis and enhanced the degree of detail relating to site classification.

The majority of PRVs were noted to be in urban areas and thus near to an electricity grid connection. As previously stated in Table 4.5, SRVs typically feed into water treatment works which require electricity grid connections. Similarly, WWTPs would have access to electricity for similar reasons. The capacity of single- and three phase supply for small scale generation is up to 20 Kw and 5 MW [105], which is suitable for MHP installations. The majority of domestic (D) and agricultural (A) consumers would be connected to a single-phase supply [106], while industrial consumers are likely to require a three-phase connection.

Based on the visual inspection process, all PRV sites were classified as domestic or industrial in Ireland and Wales, with the majority of sites in both countries identified as domestic. With the exception of four control valve sites, the maximum energy recovery at PRV sites was calculated to be 31 Kw, thus all grid connections were considered suitable for MHP installations. The control valves all exceeded this value and a three-phase connection would be considered necessary at two of the sites, with 99 Kw and 212 Kw of potential energy. These sites were considered to be in domestic areas, thus an upgrade to the local grid may need to be considered. The small number of both SRV and WWTP energy recovery sites were located in all three types of site. In total, five SRV sites and two WWTP sites were considered to exceed the 20 Kw single-phase threshold. For most of these sites, the electricity generated would be used directly on site. If it was exported, both WWTP sites and two SRV sites were located in industrial areas and the availability of a suitable three-phase supply was more probable. The visual inspection of sites improved the decision-making process and can be a more effective method of determining the proximity of an electricity grid connection. Different limits currently exist for grid connections to single- and three-phase supply for both regions. However, this may change in the future with upgrades of the grid networks. Therefore, the lack of uniformity of the grid provides a constraint for carrying out a technical feasibility of sites at a regional scale.

4.3.2 Step 2. Calculate energy recovery potential

The energy recovery potential was estimated using Eqn.1 and was based on 2011 average flow and pressure characteristic data supplied by water suppliers in Ireland and Wales. From the data supplied by water companies, a number of sites were discounted due to missing data. Almost 100 WWTP sites were omitted from the study due to low flow rates and head conditions. Table 4.6 provides the potential for energy recovery across five different generation capacity groupings.

The results from Table 4.6 show that a significant fraction of sites in both regions falls within the two lower generation capacity groups, yet these sites only contribute to a small percentage of the total estimations for energy recovery potential (10.7%). Based on previous literature, a lower threshold limit of 5-6 Kw would make these MHP installations not economically feasible [102, 103]. Therefore, a 5 Kw threshold was set at this step of the analysis to allow for sites that may cross the threshold due to variations and increases in their energy recovery potential. Of the initial 238 sites, only 80 of the sites were shortlisted for Step 3, with these sites having the potential to generate 17.9 GWh of electricity per annum. This translated as focusing development of 34% of the sites could recover 89% of the total energy potential.

Table 4.6 – Estimated energy recovery at MHP sites in Ireland and Wales for 2011.

		Energy recovery potential (Kw)					Total
		<1 Kw	1-5 Kw	5-10 Kw	10-15 Kw	>15Kw	
Ireland	No. of sites	10	13	6	6	16	51
	Potential (GWh)	0.03	0.25	0.42	0.65	7.91	9.26
	Homes supplied[1]	5	49	84	129	1,578	1,845
	Financial savings[2]	€4 k	€34 k	€58 k	€88 k	€1,084 k	€1,268 k
	t CO_2e savings[3]	14	131	223	341	4,178	4,239
Wales	No. of sites	58	77	30	10	12	187
	Potential (GWh)	0.19	1.68	1.95	1.05	5.94	10.82
	Homes supplied[1]	51	443	516	278	1,569	2,857
	Financial savings[2]	€23 k	€201 k	€234 k	€127 k	€713 k	€1,298 k
	t CO_2e savings[3]	93	810	943	509	2,869	5,225
Total	No. of sites	68	90	36	16	28	238
	Potential (GWh)	0.22	1.93	2.37	1.70	13.85	20.07
	Homes supplied	56	492	600	407	3,146	4,702
	Financial savings	€27 k	€235 k	€292 k	€215 k	€1,797 k	€2,566 k
	t CO_2e savings	107	941	1,166	850	7,047	10,112

[1] Average household consumption of 5,016 and 3,787 Kw per annum in Ireland & UK [107, 108].
[2] Disaggregated business electricity prices in 2013 of 13.7 c/kWh (Ireland) and 12.0 c/kWh (UK) [109].
[3] 2013 figures of 528 and 483 g CO_2e per kWh in Ireland & UK for electricity generation [110, 111].

In total, 238 sites were included in Step 2 of the analysis and the potential energy recovery was estimated at 20.1 GWh per annum from the water network.

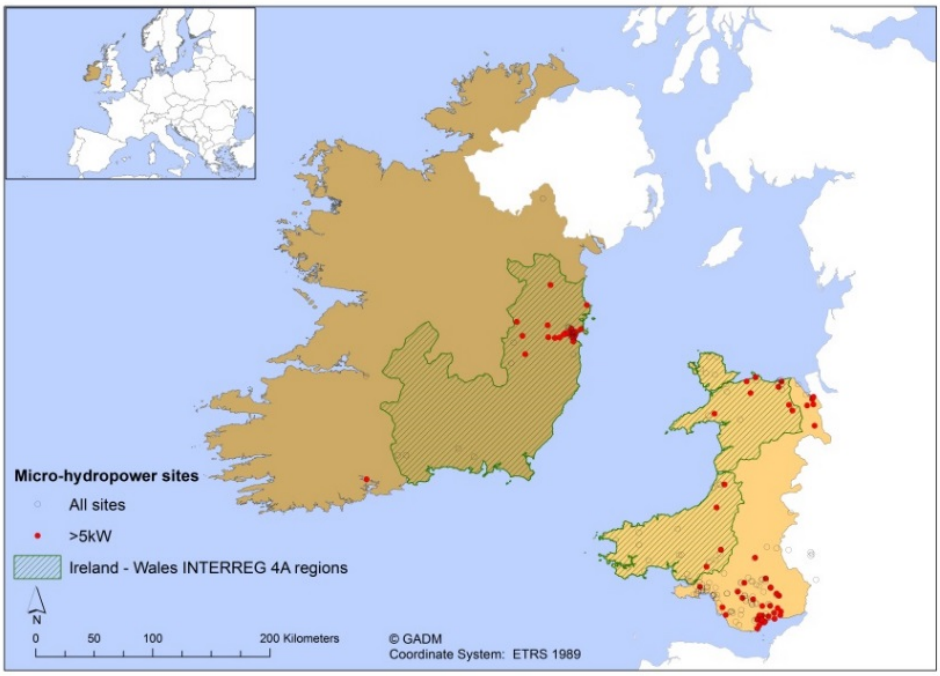

Figure 4.6 – Potential energy recovery sites (>5 Kw) from Step 1 of feasibility study for MHP installations in Ireland-Wales regions.

Based on the different types of site, Table 4.7 presents the breakdown of sites for each group. No BPTs were found to have a capacity greater than the 5 Kw threshold and thus were omitted.

PRVs represented two-thirds of energy recovery sites in both countries and almost half of the total potential for energy recovery. A similar number of SRV and WWTP sites were identified in both countries.

Table 4.7 – MHP site classification in Ireland and Wales.

Site classification		No. of sites				Energy recovery (Kw)
		5-10 Kw	10-15 Kw	>15Kw	Total	
Ireland	SRV	1	3	4	8	276
	PRV*	5	1	10	16	585
	WWTP	0	2	2	4	164
Wales	SRV	1	0	5	6	490
	PRV	25	8	5	38	397
	WWTP	4	2	2	8	134
Total	SRV	2	3	9	14	766
	PRV*	30	9	15	54	982
	WWTP	4	4	4	12	298

* Four control valves included within PRV group in Ireland.

4.3.3 Step 3. Identify technical and economic constraints

Turbine and generator selection

Examining historical flow and pressure characteristics can provide a better understanding of the long-term potential for energy recovery in water and wastewater infrastructure. In particular, PRV locations are part of the distribution network responsible for supplying domestic and industrial consumers. SRV and WWTP sites are located at the start and end of the water supply cycle and flow characteristics can be linked to growth or decline in population or industry. However, network data was not available for analysis of these sites.

A subset of ten PRV sites in Ireland (four trunk and six distribution mains) was examined to explore trends in 12 years of historical flow and pressure data. This analysis identified variations at these energy recovery sites. The maximum flow and pressure values indicated the broad range of flows that has occurred at the energy recovery sites. Expressing the standard deviation (SD) as a percentage of the average, the trunk mains demonstrated higher values (29-52%) than the smaller distribution mains (19-24%). The variability in pressure was less significant; an average SD of 23% for trunk mains compared to 13% for distribution mains (excluding 88% for Site 10 as the PRV was only fully open or closed). The capacity of these sites were all within the >15 Kw category, and variability (expressed as percentage SD) followed a similar pattern to the pressure results; 2-6% for most sites, with high pressure SD measurements of 16% and 25% at Site 10 and Site 4, respectively.

Suitability of grid connection and FIT rate

In the UK and Ireland, the government offers financial incentives such as FITs to support growth in the renewable energy sector [112]. The FIT band is selected based on the energy recovery potential of a site. A breakdown of annual differences in flow and pressure was examined for a number of sites to identify the impact of variability on selecting a suitable turbine size and maximising the income from FITs. Figure 4.7 illustrates the breakdown of annual flow and pressure variations and the energy recovery for three of the sites over the same period. Figure 4.7(a) demonstrates the unique flow and pressure characteristics of each site. The power output in Figure 4.7(b) includes the SD for each year.

The results shows that the average historical analysis does not consider circumstances where the capacity falls below the >15 Kw threshold. These findings lead to questions relating to the selection of a turbine, as future changes in flow characteristics may change the systems efficiency, the suitability of the existing grid connection and the potential to change the FIT band (e.g. from

generating less than 15Kw to greater than 15 Kw). Energy recovery from water and wastewater infrastructure is likely to be impacted due to growing populations and climate change impact on water sources.

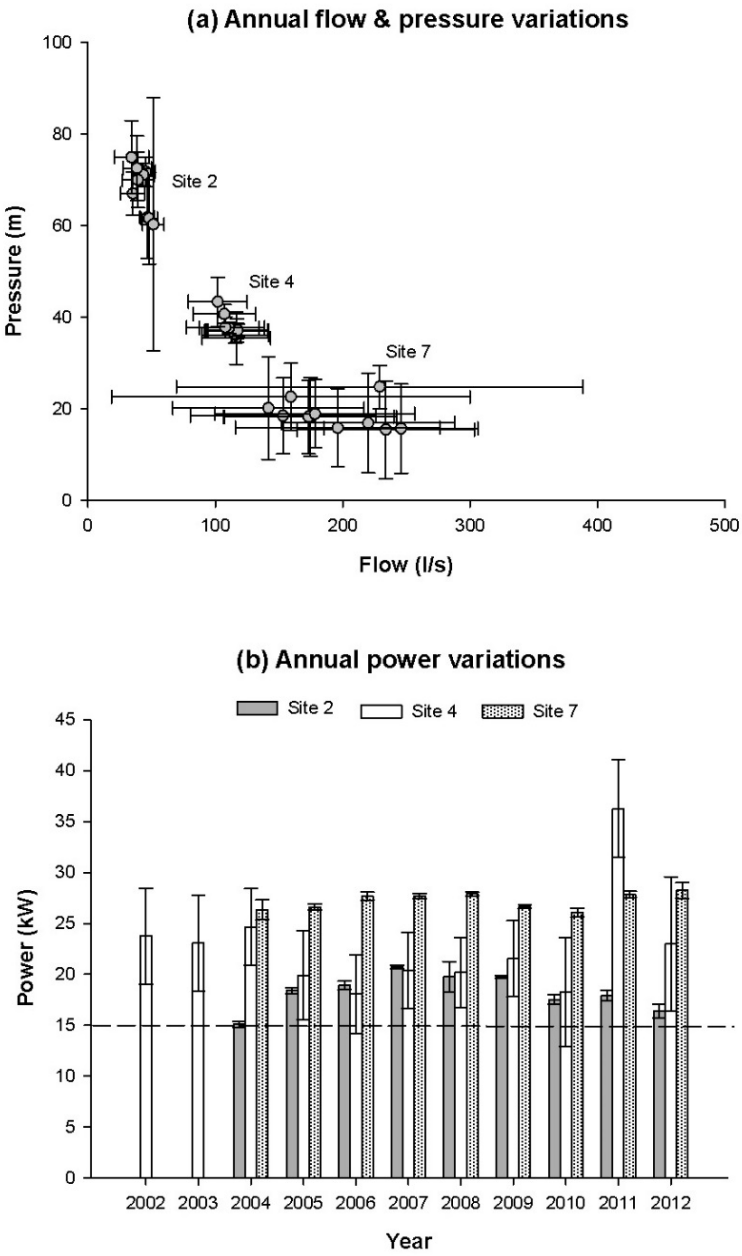

Figure 4.7 – Annual variations from 2002 to 2012 for (a) flow and pressure and (b) power at three PRV sites.

Economics of turbine selection

The International Renewable Energy Agency report notes that the cost of the turbine/generator unit varies significantly as a percentage of the total project costs [113]. This ranges in literature from 30% [89] to an average of 49% (ranging from 8% and 88%) in developing countries [20]. The British Hydropower Association (BHA) outlined the key differences in costs between low and high pressure installations, with low head projects requiring more robust equipment which makes these projects more expensive [114]. Turbine suitability was defined based on site details and costs were calculated for each site type accordingly (Figure 4.8).

The results from the economic analysis demonstrated the considerable variability in estimation of costs for MHP installations. For example, a PC turbine is necessary at PRV sites and has been

successfully implemented by water companies in the UK [115], yet is substantially more expensive than the other turbines. Based on these criteria, a sensitivity analysis was undertaken to determine what installations are economically feasible. Table 4.8 accounts for additional project costs, such as consultancy costs, civil works and grid connection. A payback of greater than 10 years was considered unfeasible based on current turbine/generator costs [116].

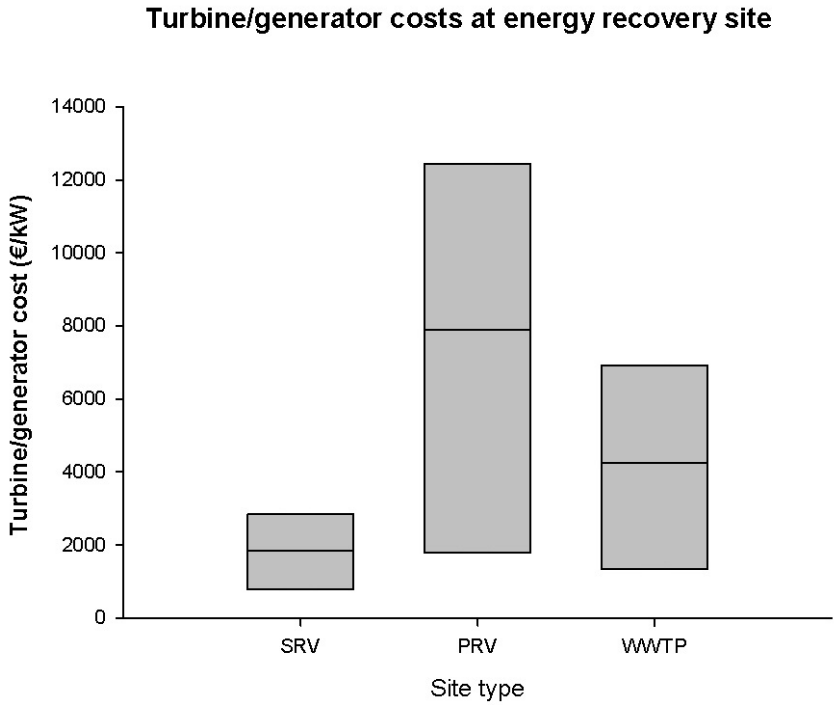

Figure 4.8 – Calculated turbine/generator costs for MHP sites in water and wastewater infrastructure (includes average, minimum and maximum costs; expressed as € per Kw capacity).

Table 4.8 – Sensitivity analysis for MHP turbines to ensure economic feasibility at water and wastewater infrastructure sites (based on current FIT rates in Ireland and Wales).

Site info			Turbine selection*	Minimum size of turbine installations (Kw) (based on % contribution of turbine/generator to total cost)		
Country	**Type**	**n**		**30%**	**50%**	**70%**
	SRV	8	Pelton	22.2 ± 16.1	13.3 ± 9.7	9.5 ± 6.9
Ireland[1]	PRV	16	PC turbine	57.8 ± 34.7	34.7 ± 20.8	24.8 ± 14.9
	WWTP	4	Kaplan	30.3 ± 22.3	18.2 ± 13.4	13.0 ± 9.5
	SRV	6	Pelton	12.8 ± 10.9	7.7 ± 6.5	5.5 ± 4.7
Wales[2]	PRV	38	PC turbine	11.3 ± 3.3	6.8 ± 2.0	4.8 ± 1.4
	WWTP	8	Kaplan	5.9 ± 4.4	3.6 ± 2.7	2.5 ± 1.9

* Most suitable turbine selected based on site flow characteristics and site requirements.
[1] FIT rate of 0.09 c/kwh generated for micro-generation set by Electric Ireland [117].
[2] FIT rate bands in UK ranging from 15-22 p/kWh and savings of 12 p/kWh for on-site use [109, 118].

Based the different payback scenarios outlined in Table 4.8, it is clear that the additional projects costs can greatly impact on the feasibility of MHP installations. It displays average costs and variability (as standard deviations) which is significant in the estimation for most installations. These results are dependent of the allowance of FITs at all energy recovery sites; however tariffs are not guaranteed at sites where pumping takes place within a network.

4.3.4 Step 4. Implement project

Based on the findings of Step 3, the results outlined projects that can be successfully implemented if they meet the capacity thresholds and select the advised turbine. Firstly, SRV sites showed the greatest potential, representing some of the highest capacity sites. The Pelton turbine

could provide a cost effective system for these sites. Based on regional FIT rates and assuming the turbine/generator accounts for only 30% of the total project costs, sites smaller than 12.8 Kw in Ireland and 22.2 Kw in Wales may not be economically feasible.

The need for pressure control turbines and the typically low potential for electricity generation highlight the challenges of ensuring an acceptable economic payback for water companies at PRV sites. If the turbine/generator is assumed to account for 70% of the total project costs, installations over 4.8 Kw are feasible in Wales based on current FITs. However, the lower FIT rate in Ireland means that PC turbines are not feasible unless energy recovery is greater than 24.8 Kw.

The Kaplan turbine was considered the most suitable for low head conditions at WWTP sites. In most cases, the economic payback was considered acceptable for sites where the turbine/generator contributed 50% of the total project costs. Energy recovery is feasible at sites greater than 18.2 Kw in Ireland and for all sites over 3.6 Kw in Wales.

The economic payback for potential energy recovery sites in water and wastewater infrastructure is sensitive to changes in FITs and the variability in costs for civil works, grid connection and turbine selection to suit flow characteristics. The feasibility of MHP implementation requires strategies to minimise project costs through adopting new and cheaper turbine technology and a modular design for a range of installation types.

4.4 Conclusions

This study assesses the technical and economic constraints for potential energy recovery sites in water and wastewater infrastructure for regions of Wales and Ireland. A structured, four-step methodology was developed to help identify potential sites for water companies.

- Step 1 helped identify different potential energy recovery sites in water and wastewater infrastructure (SRV, BPT, PRV and WWTP sites) with each site type presenting different technical challenges.
- Step 2 shortlisted eighty of the sites as the most suitable for energy recovery, with the potential to generate 17.9 GWh per annum. PRV sites represented two-thirds of the total number of sites, yet had a lower average energy recovery compared to other locations.
- Step 3 considered the technical and economic challenges of capturing this potential. Turbine selection for each type of site presented challenges based on historical flow characteristics and three turbines were assessed (two established designs and a pressure control turbine) for energy recovery at these sites. Calculated turbine/generators costs as a fraction of the total project costs varied significantly for different turbines and site types, with future Feed-in Tariffs (FITs) presenting a long term uncertainty.
- Step 4 provided evidence for the most feasible projects for Wales and Ireland based on capacity; sites larger than 3.6 or 18.2 Kw at WWTP sites, 4.8 or 24.8 Kw at PRV sites and 12.8 or 22.2 Kw at SRV sites, respectively.

However, cheaper turbine technology and better incentivisation of MHP could improve the uptake of smaller sites in the future. The results provide water companies with an estimated capacity that is feasible for potential energy recovery through MHP installations at different water and wastewater infrastructure sites.

5. LCA

Life cycle environmental balance and greenhouse gas mitigation potential of micro-hydropower energy recovery in the water industry

J. Gallagher[a], D. Styles[a], A. McNabola[b], A.P. Williams[a]

[a] School of the Environment, Natural Resources and Geography, Bangor University, Wales
[b] Dept of Civil, Structural & Environmental Engineering, Trinity College Dublin, Ireland

5.1 Introduction

Micro-hydropower (MHP) installations have recently been identified as an area of growing interest for water companies as they consider energy recovery from within water infrastructure [116]. Locations for energy recovery exist throughout water and wastewater infrastructure. The recovered energy may be used on-site to reduce net electricity demand by the water company, or be exported to the national grid. In either case, according to carbon footprinting rules [119], the carbon footprint of the industry is reduced.

Life cycle assessment (LCA) has previously been used to assess the environmental impacts of renewable energy systems [120-123]. However, the PAS 2050 carbon footprint guidelines state that it is not required to report the embodied carbon in capital goods for a renewable energy project [119]. Guidelines have been developed to calculate the embodied carbon for the water industry [124]; however, carbon and other environmental burdens of MHP installations in water infrastructure are not reported. In cases where areas of land are flooded for hydro installations, previous LCA studies have yielded high levels of GHG emissions due to vegetation decay [125, 126]. The results noted by Raadal et al. [121] demonstrated a very large variation in GHG emissions of between 0.2 and 152 g CO_2 eq./kWh. This study provides evidence relating to both the environmental impacts of MHP specific to the water industry and outlines the life cycle results for applications of the technology in water infrastructure.

5.2 Methods

5.2.1 Goal & scope definitions

The objective of this study is to calculate the life cycle environmental balance of electricity generated by three MHP installations in the water supply infrastructure. Five relevant environmental impact categories were selected from CML [127]: global warming potential (GWP), expressed as kg CO_2 eq.; abiotic resource depletion (ARDP), expressed as kg Sb eq.; acidification potential (AP), expressed as kg SO_2 eq.; human toxicity potential (HTP), expressed as kg 1,4-DCBe eq.; fossil resource depletion potential (FRDP), expressed as MJ eq. (Table 5.9).

Table 5.9 – Life cycle assessment impact categories selected to compare MHP projects with marginal UK grid electricity generation, descriptions provided [128].

Impact category	Abbrev	Units	Information
Global warming potential	GWP	kg CO_2 eq.	GHG emissions contributing to climate change and their effects on ecosystem health, human health and material welfare (measured in equivalents kg CO_2 eq./kWh).
Abiotic resource depletion potential	ARDP	kg Sb eq.	Protection of human welfare, human health and ecosystem health (measurement based on quantity of minerals extracted as a fraction of concentration of global reserves).
Acidification potential	AP	kg SO_2 eq.	Impacts of acidifying substances on soil, surface water, groundwater, organisms, ecosystems and building materials (expressed as equivalent sulphur dioxide concentrations).
Human toxicity potential	HTP	kg 1,4-DCBe eq.	Substances that are toxic to human health, calculated with USES-LCA, describing fate, exposure and effects of these substances (equivalent 1,4-dichlorobenzene).
Fossil resource depletion potential	FRDP	kg Kj eq.	Depletion of energy as fossil fuel deposits used to generate electricity (measured in equivalent kg kilojoules)

These categories were chosen as they represent the direct environmental impacts (human health, ecosystem quality and resources) associated with the hydro projects and have been previously presented in literature for renewable projects and water infrastructure projects [129-131].

The functional unit was 1 kWh of electricity generated, for comparison with marginal UK grid electricity generation via a natural gas combined cycle turbine (NG-CCT) power station [132]. The system boundaries included raw material extraction, processing, transport and all installation operations, followed by electricity generation over the lifetime of the turbines (Figure 5.9).

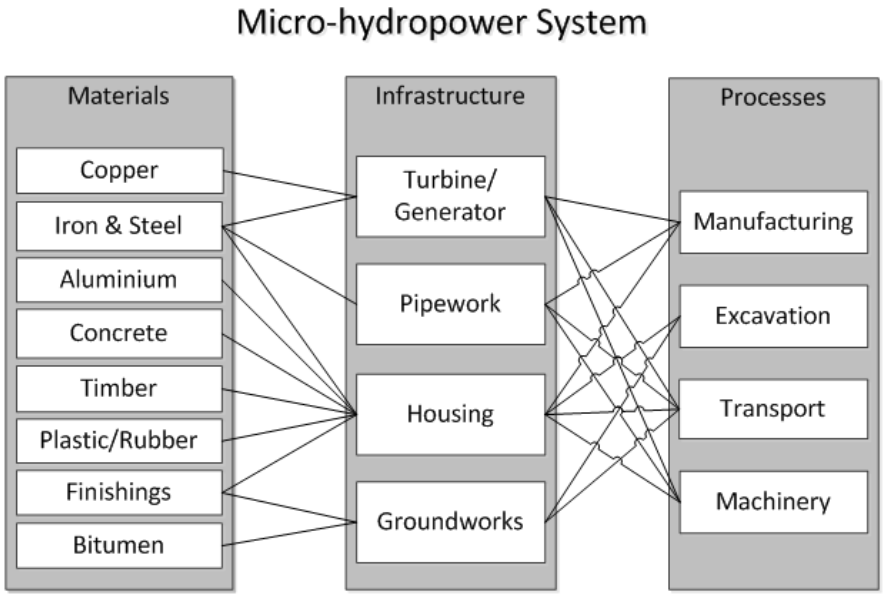

Figure 5.9 – Primary materials and processes considered within the system boundaries for MHP.

In addition, sensitivity analysis was used to determine the robustness of the results to uncertainties, and site-specific variations in manufacturing processes, materials and transportation requirements. Future projections for the carbon footprint of marginal electricity were used to predict the cumulative GHG savings over the lifespan of these MHP projects. This work aims to provide an insight into the overlooked issue of embodied carbon in MHP systems, and to provide recommendations for efficiently assessing and reporting the environmental balance of these installations. Although carbon footprinting standards such as PAS 2050 [119] exclude carbon embodied in buildings and capital equipment, the magnitude of these upstream GHG emissions in relation to avoided fossil GHG emissions is critical in determining the net GHG mitigation potential of renewable energy projects [120, 121].

5.2.2 Case study descriptions

Details relating to the three case studies examined in this paper are outlined in Table 5.10. The three MHP projects selected represent a broad range of typical installations that can take place in water infrastructure: a 15 Kw installation to control water flow into a new water treatment works, a 90 Kw new build installation to replace a dated turbine at a water treatment works, and a 140 Kw installation as part of a new water treatment works project.

A conservative nominal turbine and generator lifespan of 30 years was applied. Turbine lifespan values cited in the literature vary considerably, from 20 to 100 years [120, 122]. A number of assumptions were made during the LCA study in order to define comparable system boundaries and account for all important contributory processes. These included aspects related to materials used, products, manufacturing processes, transportation contributions, operations/maintenance and decommissioning (Table 5.11).

Table 5.10 – Description of MHP case studies for LCA [115, 133, 134].

15 Kw Pen y Cefn Water Treatment Works	90 Kw Vartry Reservoir & Water Treatment Works	140 Kw Strata Florida Water Treatment Works
		
Location: Gwynedd, Wales Dŵr Cymru Welsh Water Design capacity: 15 Kw Power output: 12.5 Kw Turbine: Zeropex Difgen Head: 90-105 m Flow: 10-30 l/s Existing housing in place Gravity fed by Llyn Cynwch reservoir New installation, flow control from Difgen turbine to DAF treatments system	Location: Wicklow, Ireland Dublin City Council Design capacity: 90 Kw Power output: 78 Kw Turbine: Kaplan Head: 7-16 m Flow: 580-1200 l/s Concrete housing constructed Gravity fed from nearby Vartry reservoir Replacing outdated Pelton wheel turbine which generated electricity for site since 1940's	Location: Ceredigion, Wales Dŵr Cymru Welsh Water Design capacity: 140 Kw Power output: 110 Kw Turbine: Pelton twin jet Head: 183-195.5 m Flow: 100 l/s GRP kiosk constructed Fed by Llyn Teifi and Llyn Egnant raw water reservoirs New installation, existing DAF system on site, 250-300 Kw energy consumption on site

Table 5.11 – Assumptions made for LCA of MHP Projects.

Assumptions	Details
Boundary conditions	Grid losses and some external infrastructure details omitted in calculations of carbon payback for MHP installations.
Project lifespan	30-year lifespan for turbines[1], 100-year lifespan for housing, 10-year lifespan for paint (further details in supplementary information).
Raw materials, manufacturing & transportation	Impact category data for raw materials (e.g. steel, concrete, etc.), manufacturing (e.g. steel product manufacturing) and transportation (e.g. freight transport) were sourced from Ecoinvent v.3 database via SimaPro8 [135]. The environmental impact of soil excavation was omitted.
Products	Estimations for the mass of raw materials contained in turbines and generators were based on consultation with manufacturers [133, 134].
Electricity generation	The power generated by the turbines is based on several years of historical data and the average power generated is assumed to be maintained over the 30-year project lifespan.
Operations & maintenance, decommissioning	Few data exist on turbine and generator maintenance burdens, which are considered trivial compared with manufacturing and installation burdens and therefore omitted from the LCA process, as for similar renewable generation LCA studies [136].

[1] Conservative nominal lifespan used as it varies in literature: 20 years [120, 123], 25-30 years [137], 50 years [138], 100 years [122].

5.2.3 Inventory for LCA case studies

To undertake a detailed LCA of the three case studies, data were collected from water suppliers and/or turbine manufacturers [115, 133, 134]. The data included the size and capacity of the turbine and generator units, the materials and construction details, including information of on-site plant and machinery. This information was extracted from a combination of sources for the purpose of the LCA, project reports, quantities spreadsheets and project design drawings.

This study followed ISO 14040 standards for LCA, and as such accounted for at least 95% of the total mass and 90% of the total energy inputs for each MHP project [139]. The LCA process is complex and time consuming [121], thus a database for raw materials and production was generated in MS Excel following extraction from Ecoinvent v.3 [135] via SimaPro software to calculate the environmental burdens of the MHP installations. The database generated included the extraction and production of raw materials, manufacturing of the products for each MHP installation, and the transportation and implementation of these products to site.

Uncertainties were noted during data collation and used to inform the sensitivity analyses, to provide transparent and representative results for these case studies [140]. A cut-off threshold of 0.5% of life cycle GWP was applied to omit minor components from the LCA. This was a lower cut-off threshold than the 1% suggested by PAS2050 and applied by Rule, Worth [122].

5.2.4 Reference system and carbon payback time

NG-CCT power stations operating at 50% conversion efficiency represent marginal electricity generation in the UK that is avoided by energy saving and renewable energy measures [46]. Therefore, 1 kWh of NG-CCT-generated electricity was taken as the reference system for comparison with 1 kWh MHP-generated electricity. The carbon payback time was calculated as the operational time required for the MHP to offset a quantity of marginal grid electricity GHG emissions equivalent to GHG emissions arising over the life cycle of MHP system manufacture, installation and operation. However, Sleeswijk, van Oers [141] outlined how LCA results may not truly reflect the environmental balance of a product over its lifetime, owing to temporal trends in the environmental burdens of contributory or counterfactual processes. A dynamic analysis was therefore applied to forecast the potential cumulative GHG mitigation potential of MHP installations based on future emission projections for marginal grid electricity generation [132].

5.2.5 Interpretation and sensitivity analysis

To enable a comparison of relative contributions to the five environmental burdens considered at the European scale, EU25 annual loading data for those impact categories were taken from CML [127] and expressed per capita, assuming a population of 465 million people. Environmental burdens per kWh were then divided by per capita loading, enabling a visual comparison of impact category contributions. Sensitivity analyses were undertaken in relation to manufacturing and transport for each MHP installation, as the most substantial level of uncertainty was noted for these project components. The following scenarios were assessed in which the environmental burdens attributable to uncertain components were varied by ±50%.

- Scenario 1 – Manufacturing of turbine/generator
- Scenario 2 – Manufacturing of pipework
- Scenario 3 – Manufacturing & construction of housing
- Scenario 4 – Transportation of materials

A sensitivity analysis was also undertaken for lifetime GHG mitigation potential for each of the MHP schemes, by considering avoidance of UK grid average electricity, and avoidance of coal power generation operating at 40% efficiency [132]. The latter scenario does not reflect current market trends but represents the high potential GHG avoidance that could be achieved if future policy measures prioritised the removal of the most carbon-intensive electricity from the grid as new low-carbon generation is introduced.

5.3 RESULTS & DISCUSSION

5.3.1 Contribution analysis

The results of the LCA are presented in Table 5.12 as the total environmental burdens per kWh of electricity generated over the 30-year lifespan by the three MHP turbines. The table also shows the carbon payback time in relation to offset grid electricity generation.

Table 5.12 – Total environmental impacts of MHP projects for different impact categories and carbon payback time (expressed per kWh generated over project 30-year lifespan).

Case study	Impact categories*					Carbon payback (years)
	GWP ($g\ CO_2$)	ARDP (g Sb)	AP ($g\ SO_2$)	HTP (g 1,4DCBe)	FRDP (MJ)	
15 Kw	2.14	1.4E-04	4.0E-02	10.05	2.7E-02	0.16
90 Kw	4.36	1.1E-04	4.3E-02	9.17	1.1E-01	0.31
140 Kw	2.78	9.4E-05	3.3E-02	8.91	6.1E-02	0.21

* GWP, global warming potential; ARDP, abiotic resource depletion potential; AP, acidification potential; HTP, human toxicity potential; FRDP, fossil resource depletion potential.

The total GWP impact associated with the three MHP installations over the lifespan of the project ranged from 2.14 to 4.36 g CO_2 eq./kWh. These results are comparable to previous results from LCA studies of hydropower projects: 5.6 g CO_2 eq./kWh for a 116 MW project [122], a conservative 15 g CO_2 eq./kWh by Gagnon and van de Vate [126], and a range from 0.3 to 13 g CO_2 eq./kWh for 11 run-of-river hydro projects [121].

Figure 5.10 displays the contribution of major components towards the environmental burdens per kWh of electricity generated for each of the turbines. The figure displays the core components (turbine/generator and pipework) and variable components (ancillary metals, concrete and other) as block and hatched sections, respectively.

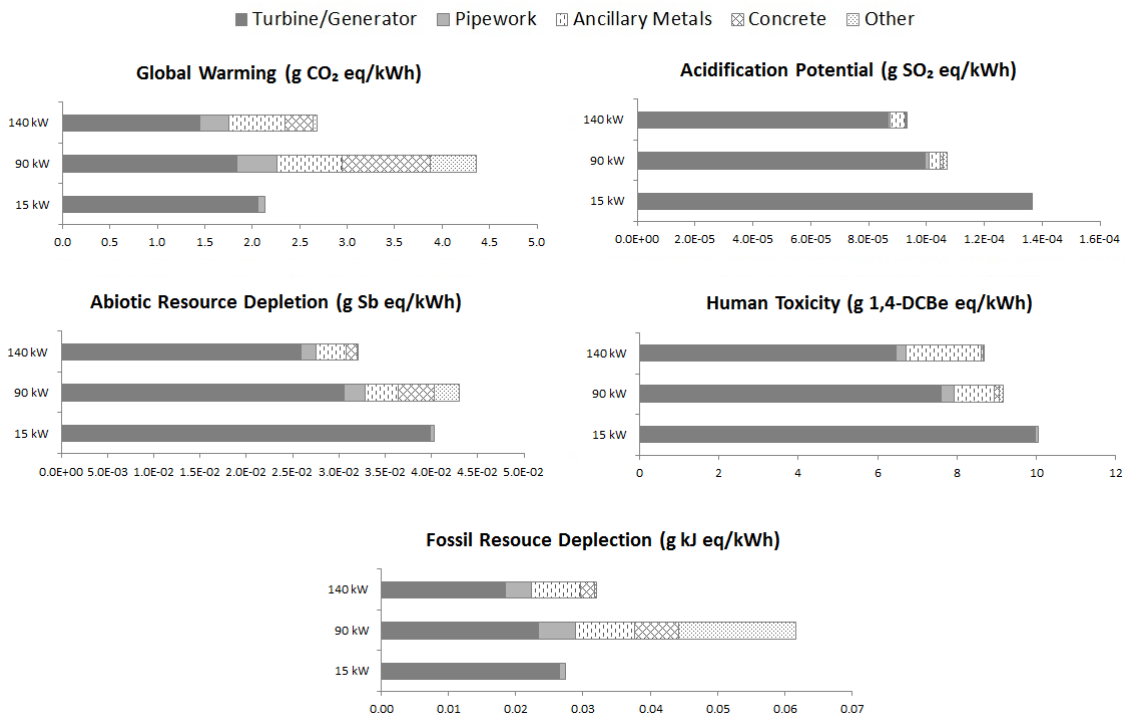

Figure 5.10 – Breakdown of environmental impacts of MHP case studies expressed per kWh generated over project 30-year lifespan (solid blocks represents core components and hatched blocks represent variable components).

The turbine/generator and pipework (solid blocks) are considered as the only two core components across each of the three projects. Turbine housing and ancillaries varied significantly between the projects. Examining all five impact categories in Figure 5.10 shows an incremental pattern for the turbine/generator, as a reduction in the capacity of the turbine related to an increase in the environmental impact of each category.

The 90 Kw MHP project demonstrated the highest contribution to GWP as the building constructed for housing the turbine/generator used more materials than the larger MHP installation. Variances in the contributions to the different impact categories between the two larger MHP projects were primarily due to the use of different types and quantities of construction materials for housing. A prefabricated kiosk was used for the 140 Kw installation in preference to a concrete structure for the 90 Kw project. Despite accounting for the longer lifespan of the 90 Kw turbine building, the quantity of materials used in its construction outweighed the structure selected for the larger installation over the nominal 30-year lifespan.

LCA has recently been adopted to quantify the environmental impacts of water systems [142], but it can also be considered as a tool for directing sustainable product design and manufacturing [143, 144]. As there was significant variability in construction practices and materials used by the three case studies examined, we could therefore consider an environmental and sustainable design approach for MHP projects.

Comparison with grid electricity

Figure 5.11 illustrates the comparative results between the three MHP installations and a 300 MW natural gas combined cycle power plant (CCPP) reference system, assumed to be a typical scale of NG-CCT marginal electricity [132].

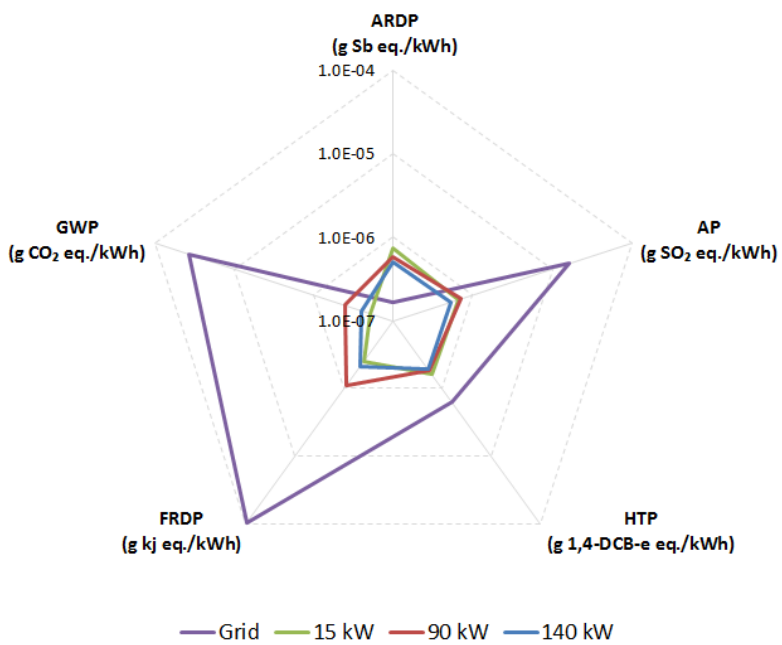

Figure 5.11. Normalised impact category contributions for each of the MHP installations compared with marginal grid electricity generation by NG-CCT reference system (compared per kWh generated over a 30-year project lifespan).

Compared with the reference system, normalised life cycle environmental burdens for MHP electricity were reduced by: > 99% for GWP; >98% for FRDP; >93% for AP; 50-62% for HTP. However, ARDP burdens were 251-353% higher for MHP than marginal grid-electricity, reflecting the comparatively large quantities of raw materials embodied in the infrastructure required to generate each kWh of MHP electricity.

Based on offsetting GHG emissions from marginal grid electricity generation, the carbon payback time calculated ranged from 0.16 to 0.31 years for the MHP projects. The payback periods for the MHP installations were significantly lower than the economic payback for the projects, which ranged from 2.8 to 8.3 years [115, 133, 134]. These figures provide lower carbon payback times than the range of 1.1 to 3.1 years for different renewable and non-renewable energy sources outlined by Guezuraga, Zauner [120]. The lower carbon payback may be due to the continuous power generation from MHP installations in water infrastructure in comparison to the irregular generation of electricity from other renewables.

5.3.2 Sensitivity Analysis

The sensitivity analysis accounted for uncertainties within the LCA process for manufacturing processes and transportation of materials to site. The results from this sensitivity analysis are presented in Table 5.13 as the percentage change in the total environmental burden from electricity generated by each MHP installation.

Table 5.13. LCA sensitivity analysis of manufacturing and transportation for MHP installations assuming ± 50% margin of error in estimating environmental burdens of project components.

Scenario	MHP installation	Impact categories* (± %)				
		GWP	ARDP	AP	HTP	FRDP
S1 – Manufacturing of turbine/generator	15 Kw	21.1%	1.9%	7.5%	5.0%	21.3%
	90 Kw	9.3%	1.8%	5.4%	4.2%	4.7%
	140 Kw	11.8%	1.8%	6.1%	3.8%	6.7%
S2 – Manufacturing of pipework	15 Kw	0.8%	0.0%	0.3%	0.1%	0.8%
	90 Kw	2.2%	0.3%	1.4%	0.7%	1.1%
	140 Kw	2.6%	0.3%	1.3%	0.5%	1.5%
S3 – Manufacturing and construction of housing	15 Kw	-	-	-	-	-
	90 Kw	9.5%	1.0%	0.6%	5.3%	1.1%
	140 Kw	6.3%	0.7%	0.9%	6.2%	1.8%
S4 – Transportation of materials	15 Kw	0.1%	0.0%	0.0%	0.0%	0.2%
	90 Kw	6.0%	0.7%	3.0%	0.4%	3.5%
	140 Kw	0.7%	0.1%	0.3%	0.0%	0.4%

* GWP, global warming potential; ARDP, abiotic resource depletion potential; AP, acidification potential; HTP, human toxicity potential; FRDP, fossil resource depletion potential.

Variations in manufacturing burdens for the turbine/generator had the most notable impact upon final results, in part reflecting the shorter (30-year) lifespans for turbines compared with other project components (see Table A1 in Appendices). The 15 Kw installation results were particularly sensitive to turbine manufacturing burdens compared with the other two projects (e.g. ± 21% versus ± 9-12% for GWP) due to the low proportion of site preparations during installation. Results were insensitive to uncertainty in the amount of additional pipework required (maximum difference of ± 2.6%), especially for the 15 Kw project where infrastructure modifications were minimal.

Overall, the default environmental burden results presented in Figure 5.10 and Figure 5.11 appear to be robust to the key uncertainties identified during the LCA study. The combined uncertainties from the manufacturing and transport scenarios equate to a potential increase in the carbon payback time of between 21-27%, equivalent to 0.19-0.40 years. The results for the carbon payback remain significantly lower than the economic payback for the three MHP installations and those of alternative forms of renewable energy available to the water industry, previously mentioned.

5.3.3 Mitigation forecasting for MHP

The three projects examined in this study have been constructed, yet there is the potential for a large number of additional MHP installations in the water infrastructure. The power generated

from the MHP installations can reduce GHG emissions from electricity and offset the carbon footprint of the water industry, but this carbon offset potential will decline over time as the carbon intensity of marginal grid electricity declines, as projected by [132]. Table 5.14 summarises the evolution of cumulative GHG mitigation for the three case studies up to 2050, making the assumption that the MHP projects are all constructed in 2014 and GHG emissions are offset from 2015. The calculations account for a reduction in the GHG emissions through offsetting electricity generated from a gas power plant.

Table 5.14. Mitigation forecasting for total GHG emissions offset by MHP installations between 2015 and 2050 (displacements of CO_2 emissions associated with gas power plant).

MHP installation	Cumulative GHG emissions offset (t CO_2 eq.)					
	Decline of marginal grid electricity					No change
	2014[1]	2015	2025	2045[2]	2050	2050
15 Kw	-7	36	450	1,206	1,379	1,873
90 Kw	-86	173	2,658	7,191	8,233	11,195
140 Kw	-80	300	3,944	10,592	12,121	16,465

[1] Assuming MHP installations constructed by the end of 2014.
[2] Signifies GHG emissions produced over the 30-year lifespan.

Over the 35 year period to 2050, the case study MHP projects are forecast to avoid between 1,379 and 12,121 t CO_2 eq., based on displacement of marginal grid electricity throughout the period. However, if grid average electricity is displaced, and assuming the carbon footprint of grid average electricity declines at the same rate as forecast for marginal grid electricity [46], then the cumulative GHG avoidance would increase by 36% for each MHP system. If MHP electricity displaces coal electricity generation over the same period, GHG avoidance would amount to three times higher than the projected savings. These results highlight the magnitude of lifetime GHG mitigation achieved by small scale MHP projects, and the sensitivity of long-term GHG mitigation forecasts to assumption about the carbon intensity of grid electricity.

DECC [132] predicts a 15-17% increase in electricity costs by 2025, suggesting that these MHP projects can contribute to mitigating energy costs, as well as helping to meet GHG emission reduction targets in the UK. The installation of energy recovery sites in water infrastructure is likely to proceed for some time after 2014, therefore the downward trend of GHG emissions associated with marginal electricity generation will increase the carbon payback period for each MHP installation by approximately 1% annually; equating to a maximum increase of 0.02 years by 2025 for a typical MHP installation. The energy forecasting for these MHP projects demonstrates significant savings in GHG emissions, and continuing short carbon payback periods into the future. As electricity prices continue to increase, MHP may become an increasingly attractive low-carbon renewable energy source into the future.

These results conclusively demonstrate the overwhelmingly positive overall environmental balance of MHP electricity generation. Only the ARDP burden is higher compared with replaced marginal grid electricity, especially where housing is constructed for the MHP turbines. However, there are various options available to reduce ARDP burdens. The variable project components (e.g. powerhouse) presents an opportunity to control materials selection such as precast concrete sections/structures, or substituting materials with more environmentally friendly alternatives could reduce ARDP burdens. Notwithstanding uncertainty over the number of material recycling loops, that will dictated by future resource prices, and allocation methodology, recycling of materials used in the MHP projects could reduce ARDP burdens by 15% (e.g. wind turbine installation [136]). The results presented in this study prefers to omit the recycling of MHP project components, as significant uncertainties exist for accurately quantifying the reuse of raw materials in future products.

Findings from within this project indicate that approximately 18 GWh of electricity can be generated through the implementation of MHP technology by water companies in Ireland and Wales [145]. Whilst implementing these systems would initially add approximately 1,700 t CO_2 eq. to the footprint of the industry, the carbon payback period for these installations would be short (0.2 to 0.4 years), and they have the potential to offset approximately 5,750 t CO_2 eq. per year and provide a 2% reduction (20 g CO_2 eq. per m^3 of water) in the GHG emissions associated with water supply and treatment [46]. The positive environmental balance of MHP technology presents an opportunity for the long-term sustainability of the water industry.

5.4 Conclusions

MHP is a growing area of interest to water companies as potential energy recovery sites can capture excess energy within water infrastructure and can generate between 5 and 300 Kw. This paper quantifies the environmental impacts of electricity generation from three MHP case studies in the water industry, using a life cycle assessment approach.

Sites may present different technical challenges to other MHP sites. Environmental burdens were therefore calculated per kWh electricity generated over nominal turbine operational lifespans. Compared with marginal UK grid electricity generation in combined cycle turbine natural gas power plants, normalised life cycle environmental burdens for MHP electricity were reduced by: >99% for global warming potential (GWP); >98% for fossil resource depletion potential; >93% for acidification potential; 50-62% for human toxicity potential. However, the burden for abiotic resource depletion potential was 251-353% higher for MHP than marginal grid-electricity.

Different quantities of raw materials and installation practices led to a range in GWP burdens from 2.14 to 4.36 g CO_2 eq./kWh. One case benefitted from very low site preparation requirements while others required substantial excavation works and material quantities. Carbon payback times ranged from 0.16 to 0.31 years, extending to 0.19 to 0.40 years for worst-case scenarios examined as part of a sensitivity analysis.

The carbon payback period for future MHP installations was estimated to increase by 1% annually, as the carbon intensity of marginal grid electricity is predicted to decline. This study demonstrates that MHP installations in the water industry have a strongly positive environmental balance.

6. Business and Collaboration

Innovation and the water industry: case studies of innovation, education and collaboration

Lucy Corcoran [a], Paul Coughlan[b], Aonghus McNabola[a]

[a] Dept of Civil, Structural & Environmental Engineering, Trinity College Dublin, Ireland
[b] School of Business, Trinity College Dublin, Ireland

6.1 Introduction

As well as investigating the technical issues related to the identification and exploitation of micro-hydropower (MHP) energy recovery in water supply networks (WSNs), the Hydro-BPT project also explored the related organisational and implementation aspects. As discussed in Section 2, there is a growing body of literature reporting on the potential for MHP in water distribution Networks across the world. However, there has been little uptake within the water industry as yet. Some of the technical reasons for this were previously discussed, including the effects of flow rate variation, and the necessity to regulate the pressure at the turbine outlet. Other issues identified in literature that may be preventing the uptake of this technology by industry include cost and policy issues. For an MHP project in a WSN to be a success, several different organisations are required to collaborate. Efficient and timely completion and implementation of a project may depend on a number of factors. Though there are few examples of installed turbines on water distribution mains, there are examples of turbines installed further upstream in the transmission network, at water treatment works and reservoirs. To gain further insight into the key factors affecting successful project implementation, a set of case studies were developed for two previously completed hydropower projects on water supply infrastructure at points in the transmission network. In this Section these two case studies from Ireland and Wales are presented, along with a cross-case comparison and the implications for future projects. The objective of this element of the project is to establish how best energy recovery projects can be implemented and replicated in practice from organisational and management perspectives.

6.2 Methodology

It was decided to develop two case studies of existing hydropower installations on the water supply infrastructure in Ireland and Wales. The selection of two cases allows for increased insights through a cross-border cross-case comparison. Two cases of the same technical type would be analysed and through these case studies, the organisational, management and regulatory issues associated with the implementation of MHP projects in the water industry were investigated. This would allow for a like-for-like comparison on the technical parameters between Ireland and Wales. Cross-border comparison also enables us to gain further insight into the management and implementation of these projects, from different water supply network jurisdictions, and also from different organisational management types.

Worldwide, water supply operation varies from completely privately operated to publically operated. The structures of these organisations may influence the adoption of new technology and also the way in which projects are deployed from an operations management perspective. These potential differences or similarities will be explored through this cross case comparison. In Ireland, water supply is predominantly publically operated, however in Wales, water supply is privately operated.

The choice of site in Ireland was limited as there are only a few examples to choose from. Currently, there are two installed hydropower turbines at water treatment works, one at Vartry Reservoir Co. Wicklow, and another at a treatment works in Co. Kerry. Dublin City Council (DCC), who were responsible for the Vartry Reservoir and waterworks at the time of writing, were members of the Hydro-BPT research project steering committee, so therefore the DCC Vartry turbine was selected for analysis due to ease of access to data.

The second site selected was a Welsh Water site at Pen y Cefn. In contrast to Ireland and other countries such as the United States, all water supply in England and Wales is privately operated. As with DCC, Welsh Water (WW) is also a member of the Hydro-BPT steering committee.

Case research methodology was employed for this analysis. Semi-structured interviews were carried out with key players involved in the two projects selected and these are summarised in Table 6.1.

Table 6.1. Case study outline.

Client	Location	Nature of Organisation	Location of Turbine	Site Type
Dublin City Council	Vartry Waterworks	Public body	Water treatment works	Retrofit
Welsh Water	PenyCefn Waterworks	Private company	Water treatment works	New build

Follow up informal interviews were also undertaken. All relevant publically available documents relating to these projects were gathered and analysed as well as some data and documents obtained from the interviewees. Interview protocol documents were prepared in advance of the two primary semi-structured interviews. These protocols outline the topics to be covered in the interviews, the questions to be asked and a list of required further data and documents. Prior to the interviews, an email was sent outlining the topics to be discussed. Copies of these interview protocol documents can be obtained upon request.

For the Vartry hydropower project, the key informant was identified to be the Vartry Waterworks Chief Engineer (CE). For the Pen y Cefn hydropower project, the key informant was more difficult to ascertain. The primary interview was undertaken on site with the turbine suppliers during their biannual maintenance checks. Another more informal interview was then undertaken with the chief operator of the water treatment plant. Interviews for each case study were performed on site, and ranged from between one and two hours in duration and included site visits to the turbines and water treatment works.

6.2.1 Organisations

The organisational structure underpinning the two water supply organisations involved in these hydropower projects differ in a number of ways, mainly due to the nature of the organisations, with DCC a public body and WW a private company.

Ireland

The water industry in Ireland, at the time of the Vartry hydropower installation, was operated by 34 local authorities throughout the country. Each local authority was in charge of the water infrastructure in their own county including sourcing the water, its treatment process and distribution. Collectively they supplied water to approximately 1.1 million households connected to public mains. Water services cost over €1.2 billion in 2010, with operational costs amounting to €715 million and a further €500 million covering capital costs. Currently only non-domestic water tariffs are implemented in Ireland collecting €200 million in water charges, meaning the €1 billion shortfall is largely State funded.

Water supply in Ireland is operated and legislated by the Department of the Environment, which is headed by the Minister for the Environment, Community and Local Government. The department of the Environment draws up legislation regarding the water industry and other environmental services under directives implemented by the EU. New infrastructure projects are generally put out to tender by project. The budget for any water or wastewater project is sought under the Department of the Environment. The funding is distributed to the local authorities through two bodies, the Water Services Investment Programme (WSIP) which covers all major water and sewage schemes costing over €1 million, and the Rural Water Programme (RWP) which covers smaller projects within the county councils [146].

In April 2012, the Irish Government announced reforms to the water industry in Ireland which included creating a new water utility company called Irish Water, a new funding model which included raising finance internationally and through water charges and the appointment of a regulator for the Irish Water Industry. Over the following 5 years the Irish Water Programme was

to go through a number of phases to gradually transfer responsibilities of the water service from the local authorities to Irish Water by 2017.

Wales

Dŵr Cymru Welsh Water (WW) provides water and wastewater services to the majority of Wales, its service area extends from the Southeast of the country up to the Northwest. WW has gone through many different stages throughout its lifetime. Originally WW was supplied by many publically owned water authorities which were privatised by the Welsh National Development Authority in 1973. With surplus cash from market stocks it began investing in many areas including the leisure and energy industry. In 2000, the company was split and the water sector was sold to Glas Cymru, a company set up purely for the purposes of taking control of WW. This was as a result of the company experiencing financial difficulties and under-investment with respect to their water services. WW today is a non-profit company with steady and predictable annual revenue streams. Since its rebirth it has progressively grown and continues to expand, redeveloping its infrastructure from the ground up.

WW are a major energy user, they are in the top ten energy consumers in Wales [147]. In 2010, WW spent £34 million on gas and electricity. However, WW are proactively developing renewable energy resources both to reduce energy bills and also to reduce their carbon footprint. WW have agreed to reduce their carbon emissions from 2007 levels by 25% by 2015, and to further reduce emissions by half by 2035 [148]. WW have a designated Energy Division who oversee the development of energy-related projects. There are three teams which operate within this division; Commercial Energy, Marketing, Energy and Operations, and Innovation and Energy. The three divisions work in a cross functional, collaborative manner. Each team has a manager whose role is to track the progress and current direction of the team. The department comprises 15 staff members and despite its size, it covers a range of different areas including energy costing and purchasing, pursuit of new renewable sources and efficiencies in all areas of water and wastewater sites.

The main concern of WW when evaluating potential new energy projects, is the project investment payback period. Projects considered feasible would have a maximum payback period of 10 years with the optimum being less than 5 years. Large scale projects like hydropower construction have large initial costs but are offset by a payback time which can be relatively short in some cases. Other projects, such as a pump upgrades, will also concern not just energy costs but repairs or replacement if the machine is coming to the end of its lifespan.

The Energy Division contracts a lot of the work involved in the projects to third party private companies. In particular, the division procured a hydro framework via the Official Journal of the European Union (OJEU) tender process. Four companies were successful in this process and they provided feasibility study services and turnkey solutions to specific hydropower projects. In their Procurement Plan (2006), WW state that they have sought, wherever possible, to build on the experience and successes of their previous partnerships in order to produce further improvements in service delivery performance and efficiency.

Summary

DCC and WW have differences and similarities in how they organise themselves and in how they approach innovation and development within their water and wastewater infrastructure. Through this cross-case analysis of the two hydropower projects, these differences and similarities will be explored in greater detail. Each of the case studies is presented in a similar format, beginning with an introduction and background, followed by a description of the key project stages for each, an analysis and discussion of each project individually and finally, a cross-border cross-case analysis is presented with conclusions.

6.3 Case Study 1: Vartry Waterworks

Vartry reservoir and waterworks supplies 75 million litres of clean water per day to parts of Dublin and Wicklow. The total water storage capacity is 16,900 million litres which is equivalent to 200 days supply at average plant output. The reservoir, located in Roundwood, Co. Wicklow (Figure 6.1) and originally dates back to the 1860s. The construction of Vartry reservoir which was completed in 1868 provided Dublin with its first water treatment works. It remained Dublins principal water supply until the development of the Liffey Scheme at Bohernabreena in 1944. It was constructed by building an earthen dam across the Vartry River valley. In the 1920s additional storage was also added with the construction of an upper reservoir which discharges to the original lower reservoir [149]. The water discharges from the reservoir via a drawoff tower and valve house to a stilling basin below, where previously the excess energy was dissipated. From the stilling basin the raw water then flows by canals through slow sand filters. Filtration is then followed by chemical disinfection and Ph adjustment.

Figure 6.1. Draw-off tower at the Lower Vartry Reservoir (L); Vartry Reservoir I.

Since November 2008, Vartry waterworks have been generating electricity through the installation of a hydropower turbine between the valve-house and the stilling basin. This recovers the energy that was previously dissipated by a throttling valve and in the stilling basin. However, this was not the first hydropower turbine to be installed at Vartry. Vartry has a long history of hydropower. The previous turbines installed used part of the incoming flow from the lower reservoir to generate electricity. The more recent turbine installed was a Pelton wheel turbine in the 1940s. The new turbine, a Kaplan turbine, was manufactured by NHT Engineering Ltd. Figure 6.2 shows the old Pelton turbine and the current turbine at Vartry.

Figure 6.2. Pelton turbine at Vartry Reservoir (L); Axial flow turbine installed in 2007 I.

This new turbine was deemed to meet the site specifications, such as the water pressure and flow rate ranges and was easy to install, maintain and operate. Water supply takes precedence over

turbine operation, therefore, in parallel with the turbine, an automatic gravity operated bypass was required to ensure that flow to the plant could not be interrupted should any issues arise with the turbine. The turbine generates 90 Kw of power, which would be enough to power between 20-30 houses per year. This turbine installation generates enough electricity to power the treatment works, with a significant amount of excess power then sold to the grid.

6.3.1 Vartry Hydropower Project Stages

This project, from its initial conception to completion can be divided into six main stages: Feasibility, Detailed Design, Planning, Construction, Commissioning and Grid Connection, as shown in Figure 6.3 below. The initial feasibility study was undertaken in March 2002, and the hydropower turbine was online and generating in November 2008, giving a total project timeline of over 6.5 years.

Figure 6.3. Vartry Hydropower Project: Stages.

Feasibility Stage

In 2002, the CE at Vartry attempted to initiate the hydropower project. In March 2002, an invitation to tender for the feasibility study was launched. Following an invitation to tender to specialist firms, three quotes were received and assessed. Energy Control Systems gave a reasonable price and ultimately found the project to be feasible and they were appointed in April 2002. Energy Control Systems had also previously completed a small hydro project on the River Liffey at Sallins. The feasibility study found that the project was technically and financially viable. A cross-flow turbine was recommended as the best choice of turbine to install. The estimated rated power of the proposed project was 150 Kw and the estimated average annual generation was approximately 700,000 kWh, the estimated forecast investment payback period was 8.3 years.

Following the feasibility study, Energy Control Systems decided to step back as they wanted to tender for the control systems. The design consultants were later confused that Energy Control Systems were not involved. A further feasibility study was also undertaken for the installation of another hydropower turbine at the upper reservoir. However the investment payback period for this was estimated at between 18 and 20 years and was therefore deemed not feasible. This reservoir is only used during peak water usage, so would not have as consistent a potential for energy recovery as at the main reservoir. However, the CE does intend to re-visit this as an option in the future.

Detailed Design

Following public tender in 2004, Fingleton White and Company were selected to design and supervise the construction of the project. They had previous experience working on other smaller energy recovery schemes, <1 MW. They were interviewed in June 2003 and appointed in December 2003. The estimated consulting costs were about 50% higher than DCC's early estimates; this increase was based on the complexity of the project.

Site investigation revealed that the complicated nature of the intake and the condition of the old pipes resulted in an additional headloss of 4m, reducing the rated power output to 20% less than originally estimated. This, combined with an ESB export limit of 60 Kw (greater would require a substantial grid upgrade fee), resulted in a decision to seek tenders for a 90 Kw turbine to supply an estimated average output of 75 Kw. The physical tests for the feasibility study consisted of tapping into the pipes at various points to take readings. There was no inflow meter at the reservoir, therefore there was some guess work involved. From these tests they learned for future projects that it is necessary to investigate the intakes thoroughly. The original pipes dating from

the 1860s consisted of many turns, expansions and contractions and so there were large head losses across them. The estimated head loss was approximately 2.6m across these pipes, however the actual headloss turned out to be higher at approximately 4m.

Fingleton White also estimated project payback period to be 8.6 years, similar to the initial feasibility study. One problem with the initial feasibility study was that the cost for the consultants was not included, so, in reality, they did not know what to expect. It was necessary for the water turbine to meet the following specifications [134]:

1. Operating heads over the range of 7 – 16 m.
2. Operating flows of 580 – 1,200 l/s.
3. Must not generate dangerous water hammer effects.
4. Able to safely withstand full runaway speed indefinitely.
5. Easy to install, operate, and maintain.

In April 2005 DCC went to tender for the turbine supplier. The consultant went ahead and negotiated with six turbine manufacturers and presented the best technical option in anticipation of a public tender. They recommended the Ossberger turbine as the most suitable. This proposed design would take 80% of the flow through a crossflow turbine. However the actual turbine selection still had to go to public tender. When it went to public tender, two companies responded, Sink and NHT, Ossberger did not.

NHT suggested that a Kaplan turbine would better suit the flow conditions. Pelton and Turgo turbines were discounted as the pressure head range is too low. However, both the head and flow ranges were well within those of Kaplan and Cross-flow water turbines. Sink, a Czech company, proposed installing a crossflow turbine. However, they had major problems with their bearings in two previous projects, within 1-2 years after installation. Following public tender, a Kaplan turbine manufactured by NHT Engineering Ltd was selected for the project. The turbine selected had water-lubricated bearings to remove the risk of oil/grease contamination of the water. It also regulated the inflow to any required pre-set level by means of hydraulically operated guide vanes linked to a flow meter. In addition, because water supply at Vartry at all times takes precedence over turbine operation, an automatic gravity operated bypass was required to ensure that flow to the plant could not be interrupted if the turbine stopped. Because water supply is the number one priority at Vartry, the flow rate is the variable that must be regulated, the power generated is secondary. A bypass is also in place in case of any electrical faults, maintenance works or other issues with the turbine. The bypass set up consists of two butterfly valves and counter weights. When the power shuts down, the turbine switches off. Oil dampened hydraulics prevent the valves from slamming.

Since installation, the experience has been that, for a variety of normal operating reasons, the electricity shuts off approximately once or twice a month. There is a stand-by diesel generator for when this occurs. The turbine will automatically attempt to restart over the course of 3 hours from the electricity short, first after 30 minutes, then again after an hour then again after 90mins.

Planning

The treatment plant is located in an Area of Outstanding Natural Beauty and is also highly visible from the public road. The new installation was carefully designed to blend with the existing plant layout and buildings and incorporates a request of Wicklow County Councils planners that the ridge-line of the new turbine house be along the same axis as the existing generator house. Planning permission was sought from Wicklow County Council in August 2004, and was granted in January 2005. The consultants had recommended not applying for planning permission as they felt it was not necessary. However to show good compliance, respect and good initiative they did apply for planning permission. There was one design change required, to move the turbine building slightly so that it could not be seen from above. Once that change was put in, planning was approved and there were no further objections.

Construction

Construction began in April 2007 (Figure 6.4 & 6.5). One issue encountered during this stage was the difficulty in dealing with the large old intake pipes. Due of the unique nature of these pipes, it was decided that DCC would do the pipework themselves as they had in-house expertise in dealing with them. It was felt that it would be difficult to find this expertise elsewhere. This intake pipework (Figure 6.4) turned out to be very difficult to manage and ended up costing 3.2% of the total project cost. Finally, due to the fact that this work was completed by in-house DCC employees, it was not eligible to be claimed for on the SEAI grant.

Figure 6.4. Vartry waterworks turbine installation (L); Turbine intake I.

Commissioning

When the project initially went out to tender for the sale of electricity to the grid, it received no realistic offers. This was in 2007, at the height of the Celtic Tiger boom period in Ireland when perhaps, there was little interest in such small projects. Another key decision at this stage was to accept the ESB export limit of 60 Kw, this meant that they could avoid paying for a grid upgrade, which is required for larger power exports, saving them additional costs. However it limited the amount of electricity that could be sold to the grid.

Figure 6.5. Vartry waterworks turbine and bypass valve (L); Kaplan turbine propeller and wicket gate I.

Grid Connection

From November 2007 to November 2008 the turbine was connected with the electrics up and running. However, with no sale agreement in place, this electricity was supplied to the grid for free. They went out to tender for the sale of electricity to the grid again one year later and received two prices this time from Bord Gais and Airtricity. Bord Gais had no maintenance cost whereas Airtricity did. By November 2008, the sales agreement was in place with Bord Gais and

the fifteen year REFIT scheme kicked in. This REFIT price is fixed for 15 years and is linked to the Consumer Price Index (CPI).

6.3.2 Discussion

As DCC did not have previous experience with a hydropower project of this scale, there were a number of unexpected hurdles to overcome. The numerous permits and legislative requirements presented a significant barrier. Applications were complex and numerous and caused significant delays. Another issue that caused delays and incurred additional costs related to the grid connection process which lead to a yearlong delay causing loss of potential revenue as well as incurring additional costs and time lost having to re-apply for permits the following year. Also, due to this delay, they did not receive the full SEAI grant that had already been approved.

One issue to bear in mind when working on a retrofit project on old water supply mains, was that the intricate pipework was very much specialist work. It was noted that it was better value and more cost saving to use the electricity generated on site where possible. It cost 14c per kWh to buy electricity and they are being paid 8c per kWh through the REFIT scheme to generate. Therefore the more economic option would be to use the electricity on site.

Finally, the overall project costs were a negative factor preventing the installation of similar schemes by other smaller local authorities, in particular the consultants costs. The breakdown of the overall project costs, as percentages of the total project cost, are presented in Table 6.2. The turbine cost was found to contribute to approximately 35% of the total installation costs. This is slightly higher than the estimated 30% that has been suggested and assumed in previous research for estimating hydropower project costs [32, 80]. There was a need for capital investment up front for this project, which many other Irish local authorities would not have readily available. However with more organised scheduling of payments this problem could potentially be avoided for future projects.

There is also an opportunity for economies of scope through sharing of expertise and consultant costs over multiple projects. This opportunity is realistic in the context of the emergence of one water authority, Irish Water. Design fees were much higher than originally anticipated. This was primarily due to the complexity of the project, having to retrofit the turbine into an existing treatment plant. The long delay in on-site commencement also meant that various approvals/licenses/sales agreements (many complex) had to be re-applied for and this resulted in considerable extra cost.

Table 6.2. Vartry Hydropower Project Costs.

Vartry Hydro Project Costs (incl. VAT)	
Work Description	**Cost (% of Total)**
Civils	35.10
Turbine manufacture & installation	34.39
Electrical Services	6.94
Intake Pipework	3.20
ESB Connection/meter	0.51
Fit Intake Screens	0.26
Manufacture Intake Screens	0.35
Planning App fee	0.03
G10 Test (grid connection)	0.17
Design and Construction Supervision	17.72
July 2002 Feasibility Study	1.33
SEI Grant	-17.28

Though setbacks and delays were encountered along the way, the project was successfully completed. The project success is investigated further later in this case analysis under different

measures of success. The Vartry experience offers us valuable insights into how future small scale hydropower developments should be implemented, especially in an Irish context.

6.4 Case Study 2: Pen y Cefn Water Treatment Works

Pen y Cefn Water Treatment Works is located in Snowdonia and serves the nearby town of Dolgellau, a small town in Gwynedd in north-west Wales, with a population of 2,678. An upgrade to the previous treatment works at Pen y Cefn was completed in May 2011. Along with this upgrade a hydropower turbine was installed. The treatment plant is gravity fed from the nearby Llyn Cynwch reservoir with raw water at a pressure of up to 10 Bar. The raw water is fed into an open dissolved oxygen flotation (DAF) tank so this pressure is not required for the process and would have previously been removed through a pressure reduction valve (PRV). As the end of the pipe into the DAF plant is elevated to a height of about 5 metres, normally a turbine would have had to be mounted at this height which would have proved challenging and expensive [88]. Welsh Water selected a Zeropex Difgen turbine to be sited at ground level. It generates electricity while maintaining the required minimum pressure at its outlet, allowing water to enter the elevated tank.

The turbine also controls the raw water flow into the treatment process by controlling its flow rate to match the desired flow. The turbine is equipped with a load bank, which allows the turbine to continue running if the electricity supply from the grid fails which allows a controlled shutdown with no hydraulic issues resulting. Key facts:

- Difgen Model: DG13-14
- Differential Pressure: 9 – 10.5 bar
- Flow Range: 10 to 30 l/s
- Power Output: 8-17 Kw (generator rated at 37 Kw)
- Annual Revenue: 29,000 GBP
- Estimated Payback Period: 2.8 years (for turbine only)

6.4.1 Pen y Cefn Hydropower Project Stages

This project, from its initial conception to completion can be again divided into stages similar to the Vartry Project: Feasibility, Detailed Design, Construction and Commissioning, as shown in Figure 6.6. The planning and grid connection phases that were included for the Vartry case, do not apply to Pen y Cefn. The turbine here was installed in tandem with an upgrade to the water treatment facility. Planning permission was required for the construction of the new water treatment works, however planning was not required for the additional installation of a turbine and, therefore falls out of the scope of this case study. The electricity generated by this hydropower turbine will all be used on-site at the treatment works, therefore the grid connection stage also does not apply. The initial feasibility study was undertaken in July 2010, and the completed installed hydropower turbine was online and generating by September 2011, giving a total project timeline of approximately 1.25 years.

Figure 6.6. Vartry Hydropower Project: Stages.

Feasibility Study

The Welsh Water Energy team undertook an in-house infrastructure wide analysis of potential hydropower sites. The initial analysis highlighted over 100 potential sites. This list was narrowed down to 10-20 sites with potential, including Pen y Cefn, to be developed during the 2010-2015 strategic Asset Management Plan (AMP5) period. A more accurate feasibility study was then undertaken of these sites by an appointed consultant. In the case of this project, the consultant selected for the Water Treatment upgrade was also used.

A risk assessment was undertaken as part of this feasibility study. The primary risk identified in this assessment was whether the project would be eligible for claiming a renewable energy feed-in tariff (REFIT). Other risks highlighted were that the Zeropex turbine is not widely proven within the UK water industry and also the decibel rating of the turbine was found to be just borderline acceptable for industrial installations. It was decided that an as-installed assessment may be required to determine if a further acoustic enclosure would be required.

Once the turbine supplier was selected, they undertook their own internal feasibility study, including an initial calculation from provided data, followed by a site visit to check site conditions.

Detailed Design
Black and Veatch were appointed as the consultants for both the water treatment works upgrade and the hydropower installation. As the Pen y Cefn hydropower turbine was installed in tandem with an upgrade to the existing water treatment facility, the construction of additional turbine housing was not required. A space was left in the new water treatment works during construction for the installation of the selected turbine. However, it was decided to install a turbine after the planning permission and design of the works, so there were some lifting restrictions due to the ceiling height in the building.

Construction
Major replacement works to the existing Pen y Cefn Water Treatment Works were required to meet AMP5 water quality drivers. The treatment works was required to triple its capacity in providing potable water to the Dolgellau area from 30,000 litres to 90,000 litres per day while also providing a new Ultraviolet treatment facility.

Construction was carried out by Dawnus, began in 2010 and was completed in May 2011. Dawnus were commissioned to undertake both civil engineering and building activities. Civil engineering work consisted of 4,000 m^3 of earthworks, 900 m^3 of concrete, 190 tonnes of reinforcement, 1,500 m^2 of formwork and 500 m of ductile pipe-work. Building work consisted of the installation of a steel portal frame, block-work and masonry, composite cladding and building finishes.

Commissioning
The turbine has been up and running and generating since September 2011. The electricity is used on-site at the water treatment works. However, Llyn Cynwch is subject to a winter refill protocol. During winter periods, Llyn Cynwch is occasionally refilled from a low level river intake to supplement the natural catchment during dry weather spells. This is currently a grey area with OFGEM/MCS and WW are in negotiations to establish a means to qualify for a REFIT. To guarantee the REFIT, the low level refill pumping station may need to be abandoned.

6.4.2 Discussion
This project was successfully completed, from initial feasibility to online and generating, in a total timeframe of approximately 1.25 years. Though the detailed feasibility study by Black and Veatch was completed in July 2010, the site would have been identified as having potential by the in-house Welsh Water Energy Bureau prior to that. This strategic site selection process successfully sped up implementation. Though the potential issue regarding the eligibility to obtain a REFIT was flagged at feasibility stage, it was decided to go ahead with the project with the hope that it would become possible to claim a REFIT at a later stage. This decision has meant that at the moment, the turbine may be on course for an estimated 22 year payback.

Despite the power generation capacity of this plant being relatively small (<10 Kw) and the payback period without REFIT being relatively long the project was successfully completed in a short space of time and with very few problems encountered along the way. This is largely due to the supportive organisational structures and policies within Welsh Water. The procurement and

tendering protocols, as well as the in-house site selection process by the Energy team, streamlined project implementation.

6.5 Cross Case Comparison

The two cases discussed differed in many ways, but both were successfully implemented. A summary of the two cases is provided in Table 6.3. The success of each of these two cases was compared based on the project outcomes using Nystroms success outcomes as a framework [150]. The three outcomes defined by Nystrom are the technological, competitive and financial outcomes.

6.5.1 Technological Outcome

The technological outcome is a rating of the technological innovation or uniqueness of the project. Both of these projects were innovative in approaches, as the use of hydropower within water supply networks is an innovative solution to pressure reduction. However, the uniqueness of these two projects can be viewed from another perspective, with regards to the type of solution required. The installation at Vartry was similar to that of any smaller scale hydropower installation. Some complexities did arise however, due to the old pipework on site to which the turbine had to be connected. However, at Pen y Cefn, the turbine was installed in tandem with the new treatment works, so retrofitting was not a problem. The complexity of the design solution at Pen y Cefn was more technologically innovative because the turbine installed was required to maintain a constant pressure at the outlet to allow the water to reach the tank above. This would be similar to the installation of a turbine in place of a PRV.

Table 6.3. Case study summary table.

	Vartry Waterworks	PenyCefn Waterworks
Location	Vartry Reservoir, Roundwood, Co.Wicklow, Ireland	Dolgellau, Snowdonia, Wales
Client	Dublin City Council	Welsh Water
Nature of Organisation	Public company	Private company
Location of Turbine	Inflow to water treatment works	Inflow to water treatment works
Site Type	Retrofit	Retrofit with new treatment works build
Rated Power Output	78kW	8-17kW
Investment Payback Period	On track for 8 year payback period	Payback without REFIT was estimated at 22 years, if REFIT is obtained payback could be reduced to approx. 7 years
Driver for Install	Largely personal project driven by Vartry engineer-in-chief	Energy team targets as defined for the AMP5 Investment period
Technological outcome	The retrofit aspects of this project required handling large, old and intricate pipework which added to complexity.	The turbine technology in this case is unique as it regulates the output pressure.
Competitive outcome	Though there exist other similar sites within DCCs water supply district, no other hydropower projects have been implemented	Welsh Water have since installed further turbines of this type at other sites
Financial outcome	This project is on track for 8 year payback and successfully obtained an SEAI grant and REFIT tariff	Without REFIT, estimated 22 year payback; 7 year payback with REFIT.

6.5.2 Competitive Outcome

The competitive outcome is the interchangeability of the product with competing products already on the market. The Vartry hydropower turbine was installed at a reservoir between the reservoir and the treatment works. This set up is not unique, and therefore the technology could be applied to other reservoirs. As highlighted in Section 4, there is similar power generation potential at other reservoirs managed by DCC, however, DCC have not installed any further hydropower turbines. DCC did not have a strategic 'system wide' plan, or long-term vision, to install further hydropower turbines. WW however, since the completion of the Pen y Cefn treatment works in 2011, have gone on to install a number of other turbines at treatment works within their water supply district. In terms of the competitive outcome and the replicability of these installations, the WW project has been more successful than the DCC project.

6.5.3 Financial Outcome

The financial outcome is a measure of the profitability of the product over its life cycle. The turbine installation at Vartry was more successful financially than the Pen y Cefn hydropower project. To measure the financial success of each project, a comparison was made of the forecasted investment payback periods.

The financial case is improved for Vartry due to the fact that the power generation at Vartry is higher (78 Kw) than at Pen y Cefn (8-17 Kw). It was also due to the fact that the specialised turbine selected to install at Pen y Cefn was expensive, despite the low generation capacity. The power generated at Vartry is enough to cover all energy demands at the water treatment works with the excess sold to the grid. In terms of investment payback, the Vartry hydropower turbine is on target for an 8 year investment payback.

At the time of writing, the Pen y Cefn hydropower turbine did not receive accreditation to allow it to qualify as a renewable energy source. It was therefore still on course for a 22.5 year investment payback period. However, WW are still pursuing accreditation which may be achieved in the future. Furthermore the interpretation of the Pen y Cefn site as not qualifying for a REFIT on the basis of the flow being pumping for a small portion of the year is a poor one. Hydropower within water supply infrastructure is by its very nature not energy production from a renewable resource, it is instead an energy saving. This achieves the same outcomes for the environment as those that the REFIT policy is attempting to incentivise. Energy consumption is reduced, less fossil fuels are therefore depleted, less CO_2 is emitted and climate change impacts of the sector are reduced. Thus to disqualify Pen y Cefn on this basis seems counter-intuitive to the objectives of REFIT.

6.5.4 Stakeholder Involvement

For both of these new hydropower projects implemented within the water industry, there was a large network of stakeholders involved that were required to collaborate and integrate. The management of these different stakeholders differed for each of the two case studies presented. Figure 6.7 illustrates the stakeholders involved at each project stage for the Vartry case study. The colour of each stakeholder bubble in the organisation map illustrates the stage during which each stakeholder was active during. The timeline follows the same colour code and provides an overview of the duration of each of these stages. The diameter of each bubble illustrates the relative impact each stakeholder had on the project. For the Vartry project, the key stakeholder was found to be the CE on site at the treatment works. DCC as an organisation, though the owners and operators of the plant, played a limited role in the project. The Pen y Cefn project, in contrast, was well supported by Welsh Water, the owners and operators of the plant. Welsh Water, in organisational context, were actively supportive, with many supportive institutional structures and policies in place to streamline implementation.

Figure 6.8 illustrates the stakeholders involved at each project stage and the related timeline for the Pen y Cefn case study. The construction stage for Pen y Cefn was shorter than for the Vartry

hydropower project because it only involved the turbine delivery, installation and set-up on site. This was primarily as a result of installing this turbine in tandem with the treatment works upgrade. At Vartry however, construction required the handling of intricate, old pipework from the reservoir, the retro-fitting of the turbine to this pipework, and the construction of a new turbine house. Furthermore, planning permission was sought for the Vartry turbine installation which was not required for the Pen y Cefn installation.

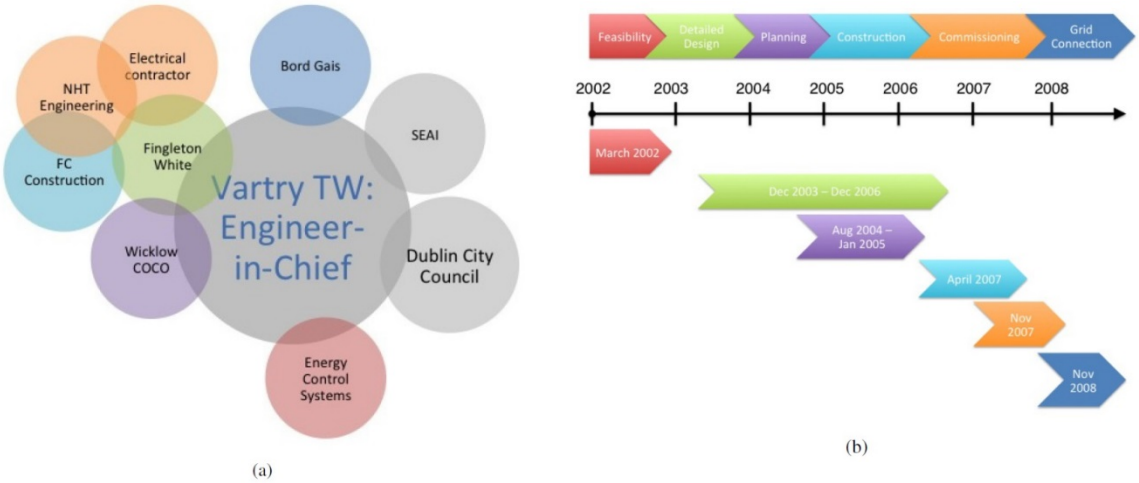

Figure 6.7 (a) Vartry organisation network and (b) Vartry project timeline.

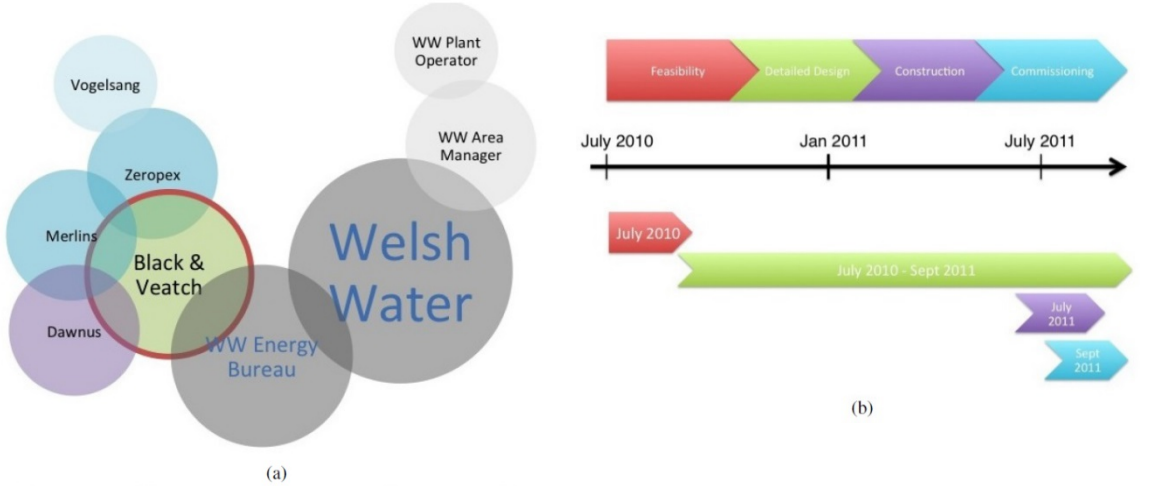

Figure 6.8. (a) Pen y Cefn organisation network and (b) project timeline.

It should be noted that while delays were not present for WW on this project, other WW hydropower sites have experienced significant delays due to legislative and planning requirements.

Another key difference between WW and DCC that led to delays for the DCC project, yet accelerated the implementation of the WW project, was the tender protocol of the two organisations. With the Vartry project, a number of tender calls were required during the project, to select, variously, a company to undertake the feasibility study, the consultants, the turbine suppliers and the contractors. However for WW, the tender process was very different. Consultants and contractors are approved as the suppliers for each AMP Investment Period. This approved them for a period of 5-15 years. Contractors were approved as Tier 1 or Tier 2 etc. A tender call is released, and tenders are awarded to a list of approved suppliers and consultants prior to each investment period. Black and Veatch were one of the approved consultants for this period in the North Wales region and therefore were automatically selected for both feasibility and consulting work. This resulted in the process running smoother and more quickly, which is

evident in the timeline. The length of time spent on the detailed design stage of the Vartry project included time spent on each individual tender call.

The timing and involvement of stakeholders active at each stage for both the Vartry and Pen y Cefn projects are summarised in Figure 6.9. From these diagrams, it can be seen that the interaction and integration during each of these projects differed. From the Vartry project diagram, it can be seen that different stakeholders or players became involved separately and one-after-the-other in a relay-race form of integration as described by Gehani [151]. For example, the initial feasibility study was carried out by one company, who then passed the baton to the consultants to complete the detailed design. DCC on this diagram is represented by the CE at Vartry, and project 'champion' as discussed previously. Meetings between the CE and other players were largely bilateral, with the consultants meeting separately with the turbine supplier and contractors.

	Feasibility	Detailed Design	Planning	Construction	Commiss-ioning	Grid Connection	Total:
Dublin City Council	X	X	X	X	X	X	6
ECS	X						1
Fingleton White & Co. Ltd		X	X	X	X	X	5
Wicklow County Council			X				1
FC				X			1
lnht					X		1
Elec					X	X	2
Total:	2	2	3	3	4	3	

(a)

	Feasibility	Detailed Design	Construction	Commissioning	Total:
Dwr Cymru Welsh Water	X	X	X	X	4
BLACK & VEATCH	X	X	X	X	4
dawnus			X		1
zeropex	X	X	X	X	4
Merlins			X	X	2
Total:	3	3	5	4	

(b)

Figure 6.9. (a) Vartry: Actors versus Stage; (b) Pen y Cefn: Actors versus Stage.

At Pen y Cefn however the interaction differed slightly. Firstly, the number of players involved was fewer. Also the same company undertook the feasibility study, detailed design and the project management. The interaction evident on this project was more consistent with a parallel or rugby styled approach as described by Gehani [151]. Different players integrated and interacted over a number of stages. This enabled the opportunity to have ongoing feedback and interaction throughout each phase.

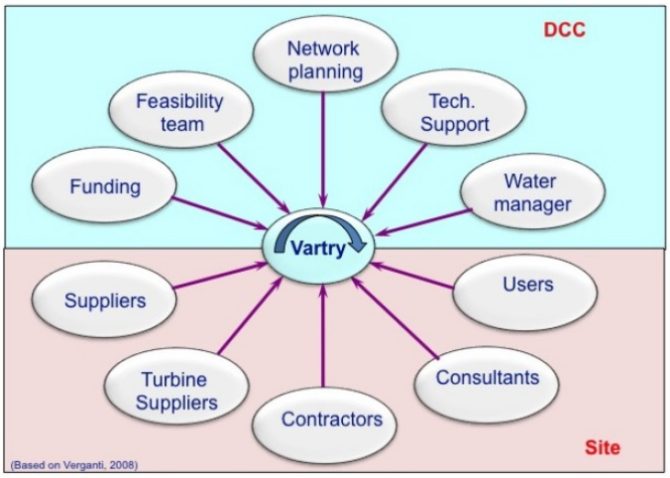

Figure 6.10. Design Discourse in DCC (adapted from Verganti [152]).

Figure 6.10 illustrates the range of different players that were involved in the Vartry project, both within DCC and on site. Together these players interacted with each other to design, develop and implement the new hydropower project. Understanding the role of each player involved in this design process, referred to by Verganti [152] as the design discourse, can lead to increased

learning and improved solutions for project implementation. A similar design discourse was present in the Pen y Cefn project, however the presence of a designated Energy Team within WW would facilitate learning and knowledge from the project to be retained and re-applied for future projects.

Barriers and Enablers

For each case study, the presence of any of the twelve barriers to sustainable urban water management (SUWM), as defined by Brown and Farrelly [153], was investigated. The results of this investigation are summarised in Table 6.4.

Table 6.4. Barriers to implementation.

Barrier to Implementation (Brown and Farrelly, 2009)	DCC Vartry Project	WW PenyCefn Project
Uncoordinated institutional framework	✓	
Limited community engagement, empowerment and participation		
Limits of regulatory framework	✓	✓
Insufficient resources (capital and human)		
Unclear, fragmented roles and responsibilities		
Poor organisational commitment	✓	
Lack of information, knowledge and understanding in applying		
Integrated, adaptive forms of management		
Poor communication	✓	
No long-term vision, strategy	✓	
Technocratic path dependencies		
Little or no monitoring and evaluation		
Lack of political and public will		
TOTAL:	**5**	**1**

From this analysis, it can be seen that the Vartry project had many barriers to overcome, including the institutional framework within DCC, and the limited organisational commitment. This was also consistent with one of the key components Jalba [154] identified that may be deficient between water utilities and other organisations, the presence of a supportive regulatory environment. However, despite these barriers, the project was implemented successfully. This was largely due to the personal interest and leadership skills of the CE on-site at the water treatment works. The CE can be seen to have acted as an emergent leader or project champion. The role of the CE in the completion of this project demonstrated the need for an emergent leader, or project champion, on an innovative project like this.

The barriers mentioned identified during the Vartry case were largely socio-institutional rather than technical. This was consistent with the theory presented by Brown and Farrelly [153] and Taylor [155] that within an environment including numerous socio-institutional barriers, emergent leaders may come to the fore to act as change agents. In the case of the Pen y Cefn hydropower project however, the installation was much more deliberate, following strategic investment into the planned development of a number of energy recovery projects during that AMP5 investment period (2010-2015). A strategic long-term vision was in place, this hydropower project was one of many to be developed as part of a strategic and coordinated investment plan. There were other drivers, such as the Water UK agreement whereby all water authorities in the UK have agreed to meet a voluntary target of reducing their carbon emissions by 20% by 2020. Also WW have set their own targets to reduce emissions by 25% of 2007 levels by 2015, and by half by 2035 [147].

The presence of a dedicated department within Welsh Water, dealing solely with the development of energy related projects also demonstrates the level of institutional and

managerial support provided. With these institutional frameworks and supports in place, the necessity for a project champion to emerge was eliminated.

6.5.5 Policy and Incentives

One key decision, clear from both cases, in the early stages of project is whether to use electricity on site or sell to the grid. If selling to grid, there is a need to engage with potential buyers as early as possible. Whether using the electricity on site or selling to grid, early clarification as to whether the scheme would qualify for a REFIT tariff is also essential. With the WW case, this issue was flagged at the feasibility stage, and WW approached the accreditation department for qualification for renewable energy feed-in-tariffs to discuss solutions.

Vartry however, did not engage early with electricity buyers, with engagement beginning only when the turbine was ready to run. Evident in these case studies was the need to engage with potential buyers as early in the process as possible. Failure to do this for the Vartry case led to a year-long delay in securing a buyer, leading to the loss of a year's revenue. Figure 6.11 illustrates the impact of earlier management focus in relation to this issue of securing an electricity buyer. In this figure, the actual Vartry project management activity to secure an electricity buyer is illustrated in red, while the blue area represents a more optimal management activity profile. The earlier the engagement to find a buyer begins, the more ability and time there is available to resolve the issue. Later engagement would lead to project delays, resulting in loss of revenue.

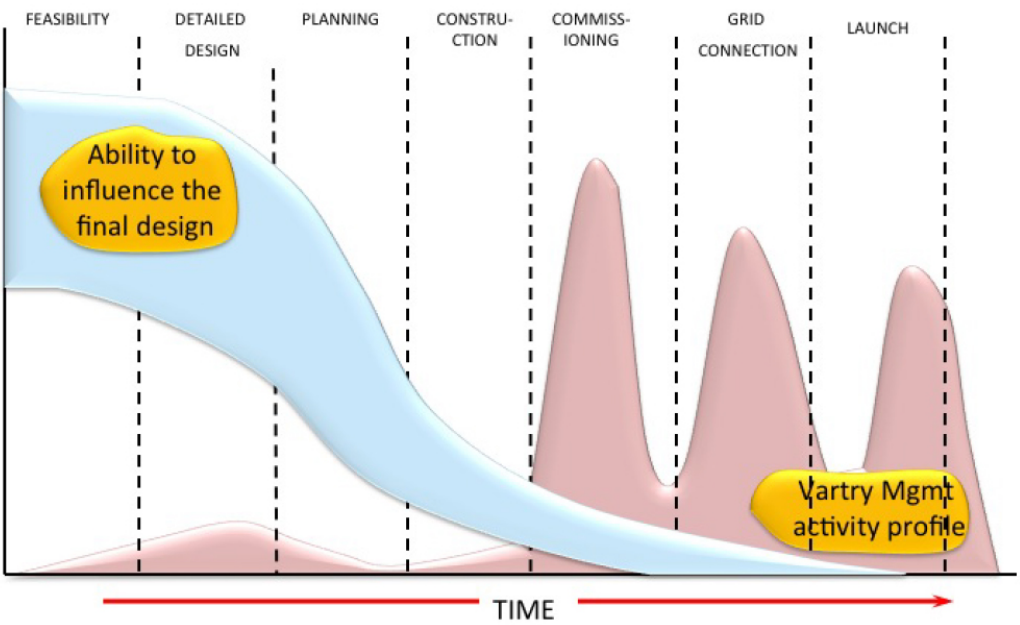

Figure 6.11. Where should the focus of management attention be? (adapted from Wheelwright and Clark [156]).

6.5.6 Planning Permission

In the Vartry case, planning permission was sought despite the consultants recommending that it was not necessary. There was no requirement for them to apply for planning, however as a gesture to ensure no local issues with the project, planning permission was sought. This decision added five months to the project timeline and also increased the overall project costs. Though it is important to engage with the local community on planned new developments, the need to do this should be carefully examined.

The Pen y Cefn hydropower project, on the other hand, did not require any specific planning permission as the turbine was housed within the new treatment works. This was a major benefit of installing a hydropower turbine concurrently with upgrades to water supply infrastructure, saving both costs and time.

6.6 Summary

The main conclusions drawn following the case analyses were that in the absence of a supportive socio-institutional framework, the presence of an emergent leader or project champion, can aid in project implementation. However, the presence of supportive institutional frameworks, mechanisms and a dedicated energy team, as has been developed within Welsh Water, has been shown to be an effective method of streamlining project implementation. It also provided a mechanism for learning through the installation of a number of turbines within each investment period.

The most influential risk to project viability and profitability lies in the ability of obtaining a REFIT. This was not a major risk for the Vartry project, due to the higher power output available and hence the increased revenue generation ability at the site. However for smaller scale power generation sites, such as the 8-17 Kw Pen y Cefn project, and likewise with many of the potential sites identified in the DCC and WW networks as discussed in Section 3, the ability of obtaining a REFIT could be the deciding factor as to whether to proceed with an installation or not.

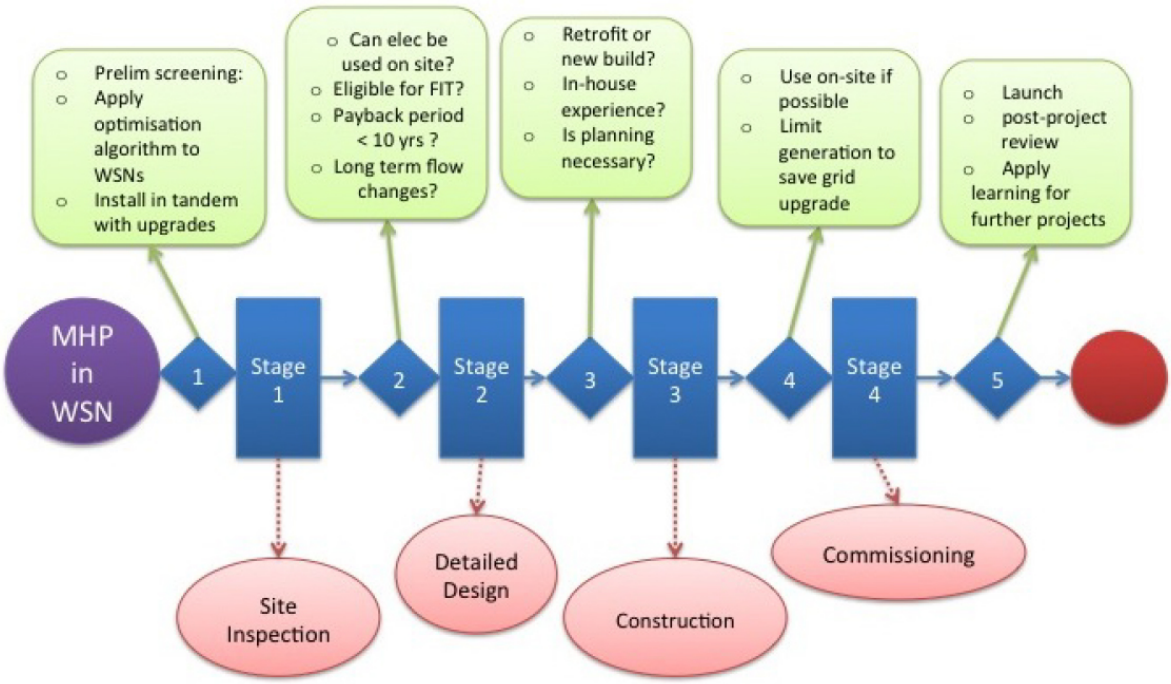

Figure 6.12. Chapter 7 Updated Framework.

Following the case description and case analyses, a modified version of Coopers Stage-Gate model was developed, with future MHP projects in mind, as shown in Figure 6.12. The first gate was focused on the identification of hydropower opportunities within the network to further investigate. Firstly, existing infrastructure locations in the network of interest should be considered. These include PRVs, BPTs and inlets or outlets to tanks, reservoirs, treatment works or at compensation flows. Furthermore, network optimisation could be applied to the Network for the identification of any new locations with hydropower generation potential, such that energy production is maximised. Planned expansion and upgrade works should be investigated for the possibility of including hydropower installations alongside these construction works. An initial calculation of the estimated power output at these sites should be evaluated, assuming average flow rates, pressure drops and a conservative system efficiency of 65%. At this stage, it is recommended that sites with estimated power outputs of less than 1 Kw should be discounted. Once a list of potentially feasible sites has been identified, the next stage is to investigate the flow and pressure conditions present in more detail and to visit the site.

Investment payback periods should be calculated with consideration paid to flow rate and pressure variation, turbine selection, and projected future changes in flow rates. If investment payback can be achieved within ten years then the project should progress to Stage 2, detailed design. Furthermore, sites with no pre-pumping that are eligible for REFITs should be prioritised for development.

Stage three was defined as the detailed design stage, followed by Stage 4, construction. Key decisions at these stages include whether or not planning permission is necessary, whether the electricity can be used on site, and whether it would be more economic to reduce the overall power generation capacity in order to save on the grid upgrade fees.

Another key factor to consider prior to the detailed design and construction phases relates to the contractors and consultants involved. Where possible, contractors and consultants who have worked on previous MHP projects with that water company should be reappointed to retain and re-apply any prior learning. Following project commissioning and launch, a post-project review process should be undertaken with all key players to document any further lessons learned for future MHP projects.

6.7 Conclusions

- The MHP Stage-Gate framework for management of operations could be applied to accelerate project implementation.
- There is a need for project leadership and this can either be from one key player involved in the project or otherwise can be organisational leadership through the development of supportive institutional policies and frameworks within the water company.
- At implementation phase there is a need to be proactive in securing a REFIT and an electricity buyer where applicable. This could improve both the cost and the time outcome of a project.

7. Future Risk Factors

The impact of long-term flow variation and climate change on micro-hydropower turbine efficiency in water supply networks

Jennifer Brady[a]*, John Gallagher[b], Lucy Corcoran[a], Paul Coughlan[c], Aonghus McNabola[a]

[a] Dept. of Civil, Structural & Environmental Engineering, Trinity College Dublin, Ireland
[b] School of the Environment, Natural Resources and Geography, Bangor University, Wales
[c] School of Business, Trinity College Dublin, Ireland

7.1 Introduction

The incorporation of micro-hydropower (MHP) turbines within water supply networks has the potential to play a valuable role in transitioning the water industry towards a more economic and environmentally sustainable form of operation. However, both long-term flow variation and the potential future impacts of climate change act as key risk factors given possible increases in hydrological uncertainty in the medium-to-long term which could substantially lengthen the investment payback period. Considering the initial high capital investment requirement, there is a need to ensure the long-term viability of a MHP installation. Using high-resolution historical flow and pressure data across a number of pressure reducing valve (PRV) sites in Dublin, this paper presents an assessment of the impact of long-term flow variability on turbine operational efficiencies and power output across a number of turbine scenarios over a twenty year period. The impact of an extreme climate event is also assessed in terms of alterations in network flow conditions. The paper concludes with engineering design recommendations regarding future MHP installations in light of potential increases in flow variability into the future.

7.2 Research design

The study comprises a number of steps in order to evaluate the efficiency resilience of varying turbine scenarios in terms of long-term flow variation and extreme climate events. Firstly, a brief background to the case study area is presented. The theoretical simulations applied to each of the turbine options are outlined and following this, both the power output and economic analysis are presented. Lastly, the study elaborates on the assessment of an extreme warm event in 2006 in terms of impacts of PRV flow rates.

7.2.1 Case study area – Dublin

Ireland's water sector has experienced historic underinvestment and has an average leakage rate of 40% [157]. Currently the Dublin region produces 550 million litres of water daily with per capita consumption estimated at 147 l/head/day [158]. Water is sourced from the Dublin and Wicklow mountains and treated in one of four water treatment plants. Supplies are currently close to demand with water treatment plants operating at 98% capacity on a daily basis [159]. Average leakage rates across the four Dublin local authorities range from 16% to 40% [157]. Yet while a total of 800 km of Dublin's supply network is over 80 years old, only 140 km has been replaced since 2007 [160]. In spite of the recent economic downturn, Dublin has experienced significant population and economic growth over the last fifteen years, with a current population of over 1.1 million [161]. It is estimated that due to population growth average daily demand is projected to exceed the maximum sustainable production capacity within the next 8 years [158].

In terms of vulnerability to climate change, a total of 55% of the population reside in the eastern half of Ireland which concurrently receives the lowest amount of rainfall at 750-1000 mm per year [162]. Potential climate change impacts will place further strains on water resources as the region is projected to experience a 20-28% reduction in precipitation during summer months by 2050 with mean temperatures likely to rise by 1.4-1.8 °C [163]. This will have a significant impact on water supplies particularly in the Dublin region.

Issues such as population growth, urbanisation and climate change will all lead to an intensification of competing demands for water in the near future which signals a serious need to manage water supplies more efficiently and effectively. This study builds on previous research regarding the energy recovery potential of the Dublin water supply network [34, 35, 116, 164] through analysis of a subset of PRV sites in Dublin (Figure 7.1) in terms of long-term variation in flow rates and the potential impact on energy recovery and capital payback periods. In this paper, the viability of three turbine configurations comprising either a hydraulic turbine or a PAT is investigated with the aim of exploring their operational efficiencies and economic suitability over the long-term.

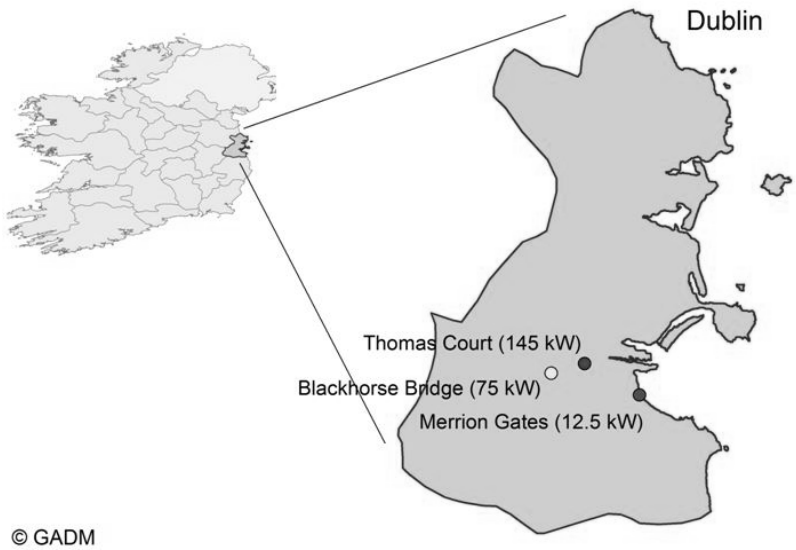

Figure 7.1. Map of the Dublin region displaying the location of the three PRV sites used in the case study.

7.2.2 Data availability

High resolution telemetry flow and pressure data at 15 minute intervals collected by Dublin City Council was utilised for simulations across three PRV sites: Thomas Court; Blackhorse Bridge; and Merrion Gates. These sites were selected as they possess different flow and head characteristics together with varied power output potential, as outlined in Table 7.1. Pressure data comprised both inlet and outlet pressure readings. The availability of data varied across sites ranging from 17 years up to 20 years.

7.2.3 Simulations

The study firstly analyses the extent of long-term fluctuations in flow and pressure across three PRV sites over a period of up to twenty years. It was anticipated that due to population and economic growth, user demand and thus flow rates would increase over the time period across the three sites.

The first year of data in each historical record is then utilised to establish a design flow for the potential turbine installation, assuming year one represents the present day. The paper then presents a theoretical simulation of the potential future performance of varying turbine options at these PRV sites over the remaining years in the historical record, assuming that these data represent future flow rates. Turbine efficiencies are evaluated over this long-term period in response to flow and pressure variation. Specifically, the power generation of a Kaplan turbine, PAT and two PATs in parallel are compared and payback periods calculated. Total reductions in CO_2 emissions are also estimated.

7.2.4 Turbine scenarios

The three turbine scenarios investigated are displayed in Figure 7.2. Firstly, a Kaplan turbine was selected due to its wide efficiency range and suitability for low head and high flow rates. Secondly, a single PAT was assessed. Whilst a PAT possesses a more narrow efficiency range, it is considerably lower in cost when compared to a conventional hydraulic turbine.

Considering this low cost, a third scenario incorporated two differently sized PATs in which a sensor would direct the flow through either a large PAT with a design flow based on the average flow rate or alternatively through a smaller sized PAT designed for 50% less than the design flow. Therefore, the optimal choice of PAT in scenario three was dependent on the incoming flow rate and flow was switched to the smaller PAT when this would produce a higher power output. This two-PAT scenario was included in order to maximise efficiency and power generation potential. Both PAT systems also comprised a hydraulic regulation device [87]. All turbine scenarios

incorporated a by-pass system to prevent disruption to the supply service in the event of maintenance requirements or failure of the turbine.

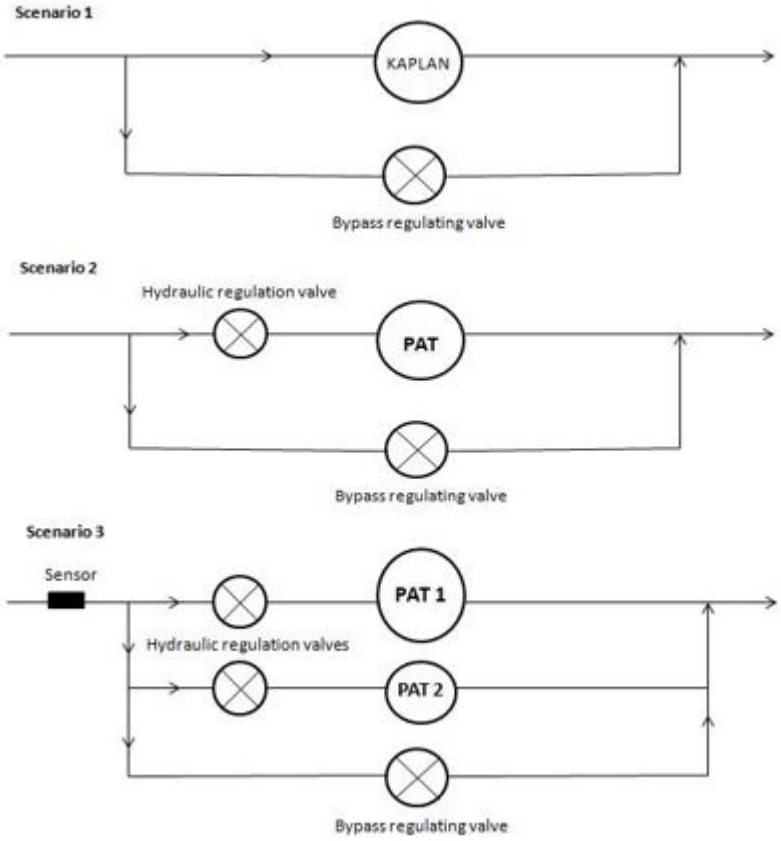

Figure 7.2. Installation schemes of three turbine scenarios; a Kaplan turbine, PAT and two PATs in parallel (adapted from [26]).

7.2.5 Power output potential and return of investment

The three sites differed regarding their estimated power potential. Table 7.1 displays the average flow rate, head and estimated power potential across the PRVs.

Table 7.1. An overview of flow, head and power output estimates for three PRVs in Dublin. Power estimates are based on varying turbine efficiencies.

PRV Location	Flow (m^3/s)	Head (m)	Estimated Power Output (Kw)
Thomas Court	0.18	70.97	145.15
Blackhorse Bridge	0.24	43.9	75.44
Merrion Gates	0.32	7.84	12.5

The potential power output was calculated every 15 minutes over the time period using Equation 7.1, where *P* represents the power output (Kw), *Q* is the flow rate through the turbine (m^3/s), *p* is fluid density (kg/m^3), *g* is acceleration due to gravity (9.81 m/s^2), *H* is the available head at the turbine (m) and e_o represents the overall system efficiency.

$$P = QpgHe_o \qquad (7.1)$$

Overall system efficiency includes a turbine efficiency value together with generator and transmission loss efficiencies estimated to be 85% and 98% respectively [165]. Turbine efficiency is dependent on flow and pressure rates. Instead of assuming a constant turbine efficiency for estimations of power output, a more accurate value was established through the use of turbine efficiency curves adapted from Corcoran et al. [35] and Ørke [166]. A sixth-degree polynomial

equation was fitted to each curve and Figure 7.3 displays an estimate of overall system efficiencies for each turbine option. In terms of historical demands and turbine design, the average flow rate over the first year of available data at each PRV site was utilised as design flow criteria for each turbine option. For the two-PAT scenario, the design flow for the second smaller PAT was chosen as 50% less than the average annual flow rate.

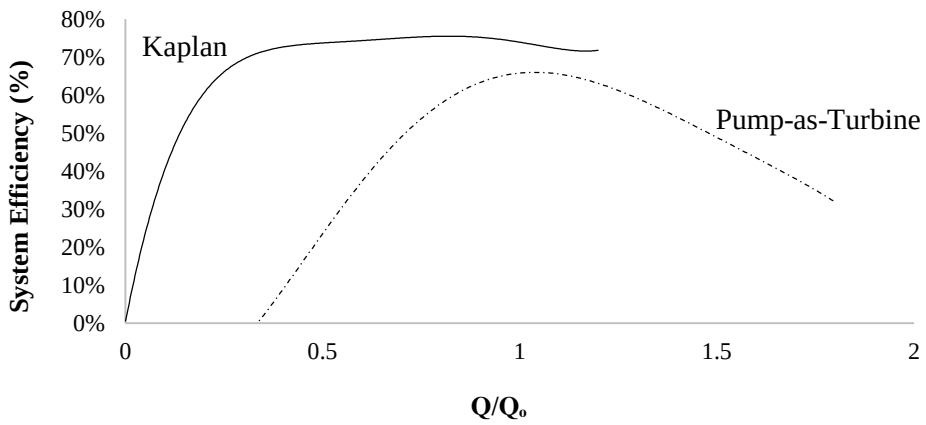

Figure 7.3. Overall system efficiency curves for the Kaplan turbine and PAT, assuming generator and transmission loss efficiencies of 85% and 98% respectively.

In terms of assessing economic feasibility, a payback period approach was applied where the payback period = (Investment cost)/(net annual revenue) [66]. In general, projects which exceed a payback period of 10 years are not considered viable by water utilities [116]. The overall costs of a MHP installation comprise the initial installation costs (design, construction, installation and commissioning) and subsequent operation and maintenance costs. Generally, MHP projects require large upfront investment costs with low recurring costs thereafter. Installation costs for a MHP turbine are mainly site specific and can differ depending on the amount of civil works needed and proximity to the grid. It has been estimated that capital costs for the installation of MHP are in the range of £3,000 to £6,000 (€3,700-€7,400) per Kw installed and costs decrease with an increase in capacity [9]. Similarly, MHP turbine installation costs in America are estimated to be in the region of $3,500-$7,000/Kw whilst maintenance costs are approximately $2,000 annually [33]. In the present study, installation costs for the Kaplan turbine were estimated using an empirical formula developed by Ogayar et al. [80] which is based on power output and hydraulic head (Equation 7.2). The cost per Kw for a PAT was estimated at €350/Kw according to previous research undertaken by Carravetta et al. [87].

$$\textit{Kaplan Cost} = 31196.P^{0.41662}.H^{-0.113901} \qquad (7.2)$$

However, both of these costs relate to the electromechanical equipment only and do not incorporate civil construction works. Generally, turbines are estimated to account for approximately 30% of total costs [145]. An existing hydropower scheme in Vartry reservoir and water treatment works, Co. Wicklow, Ireland, which comprises a Kaplan turbine (90Kw) was utilised for cost comparison. It was determined that the turbine cost represented around 30% of total installation costs, signalling that civil and construction works amounted to 70% of total expenditure. Thus, civil construction works and an additional fixed maintenance cost of €1,496 ($2,000) per annum [33] were also incorporated in the analysis.

For the purpose of this study, it was assumed that the electricity generated would be utilised on site rather than connecting to the grid, thus reducing the total investment requirement. This option has previously been found to be more economically advantageous in Ireland [35]. Accordingly, annual power generation was multiplied by the end user industrial price of electricity for 2013 of €0.137/Kw in order to establish annual electricity savings [167]. In terms of the

environmental benefit, equivalent CO_2 emissions from electricity generation were calculated based on 2013 figures of 528 g per kWh in Ireland [110].

7.2.6 Climate change analysis

Water supply systems are particularly exposed to climate change impacts. An increase in the frequency and severity of extreme events such as flooding or droughts can influence flow rates and the available energy for recovery [19, 40]. In July 2006, Ireland experienced the warmest and driest period since the record breaking year of 1995 with temperatures reaching a maximum of 31 °C. The impact of this past warm event in terms of potential fluctuations in monthly flow rates across the PRV sites was investigated utilising twenty years of historical average daily temperature data from Casement Aerodrome weather station.

7.3 Analysis and results

The overall aim of this research was to examine the potential impacts of long-term flow variation and extreme climate events on MHP turbine efficiency. This section initially explores how flow and pressure varied over a period of up to 20 years across the PRV sites. Next, by simulating the performance of a range of turbine scenarios over this time frame, economic feasibility and payback periods were estimated together with potential reductions in CO_2 emissions. The optimum turbine configuration in attaining maximum efficiency over the long-term is explored. The analysis concludes with an assessment of alterations in monthly flow rates during an extreme warm event.

7.3.1 Long-term flow variation

Average annual flow and pressure rates for each PRV site are displayed in Figure 7.4.

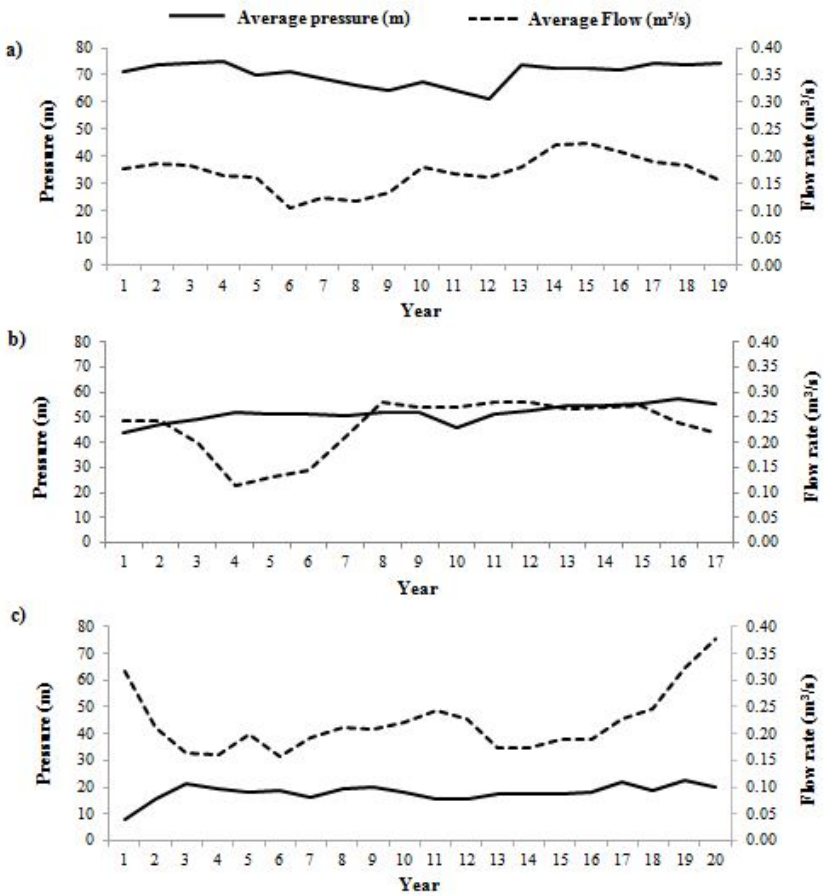

Figure 7.4. Long-term flow and pressure variation across three PRV sites. A) Thomas Court, 145 Kw (1994 – 2013); b) Blackhorse Bridge, 75 Kw (1996 – 2013) and c) Merrion Gates, 12.5 Kw (1993 – 2013).

The analysis revealed considerable hydrological variability between sites and highlights the influence of local water demands in each area. The Merrion Gates PRV, for example, serves St. Vincent's Hospital which would possess a different diurnal pattern when compared to flow feeding a residential or commercial district. Whilst it would be reasonable to forecast gradual increases in demand due to expected economic and population growth, the graphs below indicate that average flow rates actually decreased during the 1990s. Given that turbines are designed (and would be selected) according to a particular performance band, this reduction in flow rate could impact turbine efficiency and thus energy recovery. During the 2000s, a general increasing trend in demand is evident in line with the Irish economic boom period but a second prolonged decrease is observed at the smallest PRV site, Merrion Gates. Such deviation creates difficulties when attempting to optimise the turbine design flow. In contrast to flow rates, long-term variations in pressure were less extreme across sites. The graphs also demonstrate the importance of head for hydropower generation. The PRV site with the greatest power potential also possessed the highest pressure.

7.3.2 Turbine comparisons: energy recovery potential and investment payback

The impact of turbine selection on energy recovery and payback periods is presented in Table 7.2. Estimated gross income was calculated assuming an annual power generation based on the design year (i.e. performance projected based on a design flow from year one only). Actual gross income reflects analysis of the true fluctuations in power generation over the time period for this design. Both income values incorporated an annual maintenance cost of €1,496 ($2,000) and it was assumed that the electricity generated would be utilised on site. For the two-PAT scenario, the percentage of time the smaller sized PAT was in use over the period is also shown.

Table 7.2. Estimates of total energy generated, capital cost, estimated and actual gross income, payback periods and smaller PAT viability for varying turbine scenarios across three PRV sites.

PRV Location	Turbine Scenario	Total capacity (GWh)	Capital cost (€m)	Est. gross income (€m)	Est. payback (years)	Act gross income (€m)	Act. payback (Years)	% time smaller PAT in use
Thomas	Kaplan	16.98	509,080	2.765	3	2.30	4	
Court	PAT	8.78	376,200	1.063	6	1.18	7	
(145 kW)	2 PATs	9.76	386,121	1.211	6	1.31	5	35
Blackhorse	Kaplan	14.01	409,392	1.332	5	1.90	5	
Bridge	PAT	8.88	306,921	1.021	5	1.19	6	
(75 kW)	2 PATs	9.38	317,095	1.070	5	1.29	6	26
Merrion	Kaplan	3.52	235,375	0.239	19	0.45	11	
Gates	PAT	1.97	168,129	0.178	18	0.24	16	
(12.5 kW)	2 PATs	2.64	169,813	0.193	17	0.33	10	52

Findings reveal that significant power generation capacity exists across each of the scenarios. The Kaplan produced the greatest amount of energy across all sites, however, it cost approximately 25% more to install than either a single PAT or two PATs. This is in line with previous research which also highlighted the lower cost of PATs when compared to conventional turbines [22, 168]. Furthermore, the cost difference was greater at the site with the lowest power output potential (the Kaplan turbine cost 29% more than a PAT and 28% more than two PATs). In contrast, the cost differential between a single PAT and a two-PAT configuration was considerably lower across all of the PRV sites (1-3%).

Acceptable payback periods were identified for those sites with medium and larger power capacities, although the actual payback period was generally higher than estimated across these sites. The installation of a single PAT had the longest payback across all sites whilst the Kaplan was

the optimal turbine regarding the shortest payback period. However, the difference in payback between the Kaplan and two PATs was only one year in total. In terms of the PRV with the smallest power potential (Merrion Gates), only the two-PAT scenario was found to have an economically viable payback period. Based on the design flow data (i.e. year one only), the initial payback estimates indicated that none of the turbine scenarios would achieve a viable payback period. However, the effects of considerable flow variation over the twenty years meant that the second smaller PAT was the optimal turbine 52% of the time. Figure 7.5 illustrates the two-PAT scenario in greater detail indicating the effects of long-term flow variation on turbine efficiency and viability. Evidently, this site exhibits high flow variability and as the flow rate decreases, deviating from the turbine design flow of the larger PAT, the second smaller PAT becomes the optimum choice in maximising efficiency and power output. Interestingly, the smaller PAT was utilised less frequently across the larger PRV sites due to less changeability in flow conditions.

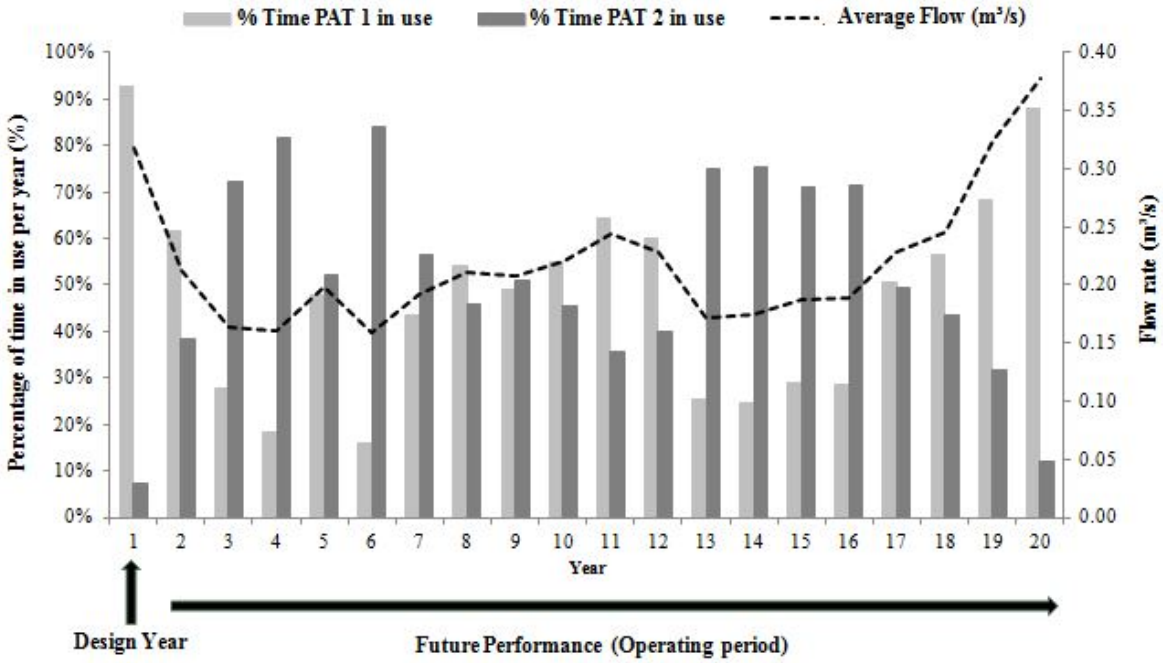

Figure 7.5. Long-term annual flow variation and performance of a two-PAT scenario at Merrion Gates PRV, displaying an annual breakdown of the percentage of time each PAT option was the optimal choice in achieving maximum turbine efficiency. PAT 1 represents the larger PAT developed for the design flow whilst PAT 2 is designed for 50% less than the design flow.

From an environmental output perspective, Table 7.3 highlights the total CO_2 emission savings from electricity generation for each turbine option.

Table 7.3. Comparison of estimated CO_2 emission savings for varying turbine scenarios across three PRVs in Dublin.

PRV Site	Turbine Scenario	Total CO_2 emissions savings (tonnes)
Thomas Court (145 kW)	Kaplan	8,967
	PAT	4,635
	2 PATs	5,154
Blackhorse Bridge (75 kW)	Kaplan	7,396
	PAT	4,688
	2 PATs	4,953
Merrion Gates (12.5 kW)	Kaplan	1,860
	PAT	1,042
	2 PATs	1,394

The Kaplan achieved the greatest savings potential across all PRVs and almost double that of a single PAT at Thomas Court PRV, the site with the largest power output capacity.

7.3.3 Climate change and flow variability: impact of extreme events

An increase in the uptake of renewable energies concurrently leads to greater dependency on climate and weather parameters [169]. In order to understand potential future climate change impacts on flow conditions in water networks, this study assessed the effects of a past extreme episode on PRV flow rates using historical meteorological data. Analysis of mean monthly flow rates across three PRVs during this period revealed a reduction in flow of between 0.04% and 14.6% over the month of July in which the drought period occurred, signifying that the severity of the impact varies considerably across sites. Thomas Court PRV displayed the greatest vulnerability to changes in flow at 14.6% and this could threaten the accuracy of design flows for turbines, particularly in light of projected increases in the number of extreme events into the future [163]. Further potential influencing factors in terms of the variation in vulnerability to climate impacts include the supply zone location of the PRV site and the category of end user, such as an industrial or residential setting. Thus, tailoring the right turbine solution to the right location is paramount in reducing turbine performance vulnerabilities.

7.4 Discussion

This research revealed the potential risks posed by long-term flow variation and climate change impacts in terms of energy recovery of MHP installations into the future, thus highlighting the importance of their consideration when estimating turbine suitability. The incorporation of high resolution flow and pressure data allowed for a more realistic assessment of power potential over the long-term given the detailed diurnal, daily, seasonal and annual fluctuations in flow rates which can influence turbine efficiency and viability into the future. Projected climate change impacts such as increased flow variability and more frequent hydrological extremes signal the need to design for greater resilience in MHP energy recovery systems.

7.4.1 Long-term Flow Variation Across Sites

The analysis of long-term flow and pressure data across a number of PRVs identified considerable fluctuations in flow conditions across sites even within the same region. Thus, site characteristics such as the district type e.g. commercial or residential play a strong role in overall demand requirements. It was anticipated that demand would increase in line with economic and population growth but not all sites reflected this. The smallest PRV, Merrion Gates, experienced a reduction in demand during the 2000s. Such variation in flow conditions indicates the complexity in determining an optimum design flow for a turbine. Thus, anticipating the challenge of long-term flow is vital when assessing the potential feasibility of varying turbine options. Accordingly, in order to achieve maximum energy recovery and long-term viability of such installations, improved flexibility in turbine operation is essential where flow and pressure deviate substantially. The findings further revealed that pressure is a dominant factor governing power generational capacity across PRV sites within supply networks.

7.4.2 Turbine comparisons and the role of PAT technology in accommodating increased flow variability

In order to advance the uptake of MHP technology a viable installation must comprise a minimum payback period, maximise power output and revenue generation and reduce CO_2 emissions. Furthermore, it must have the adaptive capacity to accommodate changing flow conditions over the long-term. The impact of long-term flow and pressure variation on estimated energy recovery and investment payback periods across three turbine scenarios revealed some valuable insights.

Firstly, the conventional Kaplan turbine was the optimal choice in terms of payback periods at the PRV sites with greater power output potential, whilst a single PAT installation had the longest payback across all sites. However, the payback period differed by only one year between the

Kaplan and two-PAT scenario. In terms of environmental benefit, the Kaplan produced the greatest reduction in CO_2 emissions; between 37% and 48% more than a single PAT and between 25% and 43% more than a two-PAT option when comparing sites. Yet, a significant disadvantage with the Kaplan is that it cost 25% more to install when compared to either a single PAT or two PATs in parallel and this cost differential increased even further when assessing economic viability at the smallest PRV site. Furthermore, the miniaturisation of traditional turbine types such as the Kaplan is known to be prohibitively expensive, rendering them unsuitable for the large number of potential MHP energy recovery sites with small output capacities.

The limits of conventional turbines such as the Kaplan are evident at sites with smaller power capacities. The findings indicated that the two-PAT scenario was the only economically viable option at the Merrion Gates PRV site which had the smallest energy recovery potential of 12.5 kW and the greatest flow variability. In contrast the single PAT displayed a significantly longer payback period of 16 years whilst the Kaplan had a payback of 11 years and considerable upfront costs. The notably cost effective option of a PAT when compared to a Kaplan, allows for the possibility of integrating more than one PAT in series at minimal extra cost. This turbine solution of multiple PATs with varying design flows in order to cater for flow variation can improve the overall energy generation potential of PATs and the low installation cost coupled with comparable payback periods when compared to conventional turbines highlight its economic advantages.

Thus, the integration of PAT technology within water supply networks opens up the opportunity to harness untapped recoverable energy at sites with smaller power generation potential and in locations where there exists large hydrological variability, sites which may previously have been considered unsuitable for MHP.

7.4.3 Long-term change and extreme events

MHP energy recovery is a natural fit for water utilities. However, the findings revealed that climate change in the form of an extreme warm event could negatively impact turbine viability through reduced flow rates in the water network. Thus, extreme warm events can be used as an important indicator in further research measuring potential impacts of climate change on MHP into the future.

An additional finding was the extent of variation in flow conditions between PRV sites during the warm episode which indicates that particular zones are potentially more vulnerable to climate change events than others. A valuable insight would be to determine the predominant type of end user setting in which the PRV is operating such as residential, commercial or industrial, in order to identify which zones display greater vulnerability to flow reductions during extreme events. Such issues reiterate the need for flexible engineering design of MHP turbines in order to increase resilience to significant changes in flow conditions and maximise performance and profitability. In light of the findings of the turbine comparisons, the two-PAT option could be a viable solution for small capacity sites, thereby assisting water utilities in managing risk and increasing climate change resilience.

7.4.4 Developing planned flexibility in order to anticipate and respond to future risks

Water utilities presently face a situation in which they must invest in water management systems under an uncertain hydrological future. Organising for such uncertainty requires the development of a particular organisational capability, such as planned flexibility [170], which is a project specific capability to identify likely critical decision areas early and to anticipate the reaction measures which may be required to manage these critical areas later in the project. The early detection of critical areas together with the early planning of the flexible measures to deal with uncertainty can enable the utility to postpone successfully the decision into the implementation phase. Planned flexibility reflects the accumulation and application of learning from experience in practice, without which any purely reactive approach would lead to poor performance.

This study highlighted the risks posed to MHP energy recovery from both long-term flow variation and extreme climate events. By systematically anticipating and planning for these risks in the initial planning phase of projects and recognising that increased flow variation may be a future issue, this allows for more effective corresponding reaction measures and the accumulation of practice-based data for future application. The results indicated that the implementation of a two-PAT parallel system for energy recovery could be a viable adaptive design technology solution which demonstrates planned flexibility in order to more effectively manage such risks at small capacity sites.

7.4.5 Limitations and areas for further research

The hypothetical scenarios presented in the current study where each turbine was designed based on one year of historical data and its performance was assessed across the subsequent 16 to 19 years was useful to examine performance variability over time. However, in practice, hydropower turbine designers will not know the future flow rate over the coming 20 year period, making the design of turbines which cater for future flow variations difficult. The use of water demand forecasting models have an important role to play here to enable the variation in flow at PRVs in water distribution networks to be predicted over the long-term.

Furthermore, the current approach presented a two-PAT scenario in which the smaller PAT was designed for 50% less than the design flow. In essence, a range of alternative design flows could be incorporated. Optimisation research of various design flow options and in terms of the optimum number and size of PATs would allow for improved decision making for utility managers regarding the most economically advantageous PAT configuration.

Whilst this study identified the effects of an extreme past event on flow rates at various PRV sites, additional research is required to investigate potential climate change impacts on MHP energy generation and economic viability into the long-term. Further risk factors which also need to be considered are socio-economic aspects including population growth and shifting demographics together with government policies such as REFIT schemes and future energy pricing.

7.5 Conclusion

MHP represents a viable pathway to a more sustainable system of water supply, yet uptake of this technology remains sporadic due to a range of risk factors including long-term flow variation and climate change impacts. The focus of this study was to undertake a detailed investigation of the impact of long-term flow variability on turbine operating efficiencies and power output across a number of turbine scenarios over a twenty year period using Dublin as a case study site and to understand the potential influencing effects of extreme climate change events.

Findings revealed considerable variation in long-term flow conditions, particularly at PRV sites with smaller power generation capacities. Following investment payback analysis, the Kaplan was found to have the shortest payback period and achieve the largest saving in CO_2 emissions across both medium and large sites. However, neither the conventional turbine nor single PAT were economically viable at the smallest PRV site. Although there was an evident reduction in power generation, the two-PAT scenario proved to be economically viable despite the increased flow variability. Furthermore, this option was almost comparable with the Kaplan in terms of payback period across the remaining sites and had a significantly lower installation cost. Thus, the incorporation of multiple PATs in parallel represents a viable technology option which demonstrates planned flexibility and provides greater resilience to future fluctuations in flow and pressure conditions, enhancing the adaptive capacity of MHP systems into the long-term. The present study is of relevance for water utilities as it highlights an adaptive design option to maximise energy recovery potential within water distribution networks. Accordingly, the findings strengthen the evidence base for greater uptake of MHP technology.

References

1. Darrel Jenerette, G. and L. Larsen, *A Global Perspective on Changing Sustainable Urban Water Supplies.* Global and Planetary Change, 2006. **50**(3–4): p. 202-211.
2. Brown, L.E., et al., *Priority Water Research Questions as Determined by UK Practitioners and Policy Makers.* Science of The Total Environment, 2010. **409**(2): p. 256-266.
3. Kwok, S.C., et al., *Water technology markets 2010 : key opportunities and emerging trends*. 2010, Oxford: Media Analytics Ltd. xxiii, 189 p.
4. Berndtsson, J.C. and K. Jinno, *Sustainability of urban water system: examples from Fukuoka, Japan.* Water Policy, 2008. **10**(No. 5): p. pp. 501-513.
5. Zilberman, D., et al., *Rising energy prices and the economics of water in agriculture.* Water Policy, 2008. **10**(No. S1): p. pp. 11-21.
6. Rygaard, M., P.J. Binning, and H.-J. Albrechtsen, *Increasing Urban Water Self-Sufficiency: New Era, New Challenges.* Journal of Environmental Management, 2011. **92**(1): p. 185-194.
7. Hernández Leal, L., et al., *Bioflocculation of grey water for improved energy recovery within decentralized sanitation concepts.* Bioresource Technology, 2010. **101**(23): p. 9065-9070.
8. Park, S.-W. and C.-H. Jang, *Characteristics of carbonized sludge for co-combustion in pulverized coal power plants.* Waste Management, 2011. **31**(3): p. 523-529.
9. Gaius-obaseki, T., *Hydropower opportunities in the water industry.* International Journal of Environmental Sciences, 2010. **1**(3): p. 392-402.
10. McNabola, A., P. Coughlan, and A.P. Williams, *The technical & economic feasibility of energy recovery in water supply networks*, in *International Conference on Renewable Energies and Power Quality*, M. Perez-Donsion, Editor. 2011: Las Palmas de Gran Canaria.
11. EA, *A low carbon water industry in 2050*, in *Evidence*. 2009, Environment Agency: Bristol. p. vi, 41 p.
12. Ramos, S., et al., *Advantage of Public Water Supply Use for Micro Power Generation*, in *Proceedings of the International Conference on Renewable Energy and Power Quality*. 2009: Valencia, Spain.
13. Li, Z., F. Boyle, and A. Reynolds, *Rainwater Harvesting and Greywater Treatment Systems for Domestic Application in Ireland.* Desalination, 2010. **260**(1-3): p. 1-8.
14. Lofman, D., M. Petersen, and A. Bower, *Water, Energy and Environment Nexus: The California Experience.* International Journal of Water Resources Development, 2002. **18**(1): p. 73-85.
15. Venkatesh, G. and H. Brattebø, *Energy consumption, costs and environmental impacts for urban water cycle services: Case study of Oslo (Norway).* Energy, 2011. **36**(2): p. 792-800.
16. Zakkour, P.D., et al., *Developing a sustainable energy strategy for a water utility. Part I: a review of the UK legislative framework.* Journal of Environmental Management, 2002. **66**(2): p. 105-114.
17. Zakkour, P.D., et al., *Developing a sustainable energy strategy for a water utility. Part II: a review of potential technologies and approaches.* Journal of Environmental Management, 2002. **66**(2): p. 115-125.
18. Howe, A., *Renewable energy potential for the water industry*. 2009, Environment Agency: Bristol, UK.
19. McNabola, A., et al., *Improving Energy Efficiency in Water Infrastructure using Micro-hydropower Energy Recovery: Opportunities & Challenges*, in *2nd International Symposium on Energy Challenges and Mechanics*. 2014: Aberdeen, UK. p. pp1-8.
20. Khennas, S. and A. Barnett, *Best practice for sustainable development of micro hydro power in developing countries*. 2000, London Economics & deLucia Associates, Cambridge Massachusetts, USA: The Schumacher Centre for Technolgoy and Development.
21. Da Silva, B.L.A., F.L. Tofoli, and L.S. Scartazzini, *Case Study: Hydroelectric generation employing distribution network in pato branco, Brazil*, in *Proceedings of the IASTED International Conference on Power and Energy Systems*. 2011: Crete, Greece.
22. Williams, A.A., *Pumps as turbines for low cost micro hydro power.* Renewable Energy, 1996. **9**(1–4): p. 1227-1234.
23. Williams, A.A., et al., *Pumps as Turbines and Induction Motors as Generators for Energy Recovery in Water Supply Systems.* Water and Environment Journal, 1998. **12**(3): p. 175-178.
24. Fecarotta, O., et al., *Hydropower Potential in Water Distribution Networks: Pressure Control by PATs.* Water Resources Management, 2015. **29**(3): p. 699-714.
25. Mikus, K., *Erfahrungen mit Kreiselpumpenanlagen zur Energieruckgewinnung aus dem Trinkwassersystem.* Das Gas und Wasserfach - Wsser/Abwasser, 1984. **124**(4): p. 159-163.
26. Carravetta, A., et al., *Energy Production in Water Distribution Networks: A PAT Design Strategy.* Water Resources Management, 2012. **26**(13): p. 3947-3959.
27. Carravetta, A., et al., *Pump as Turbine (PAT) Design in Water Distribution Network by System Effectiveness.* Water, 2013. **5**(3): p. 1211-1225.
28. Carravetta, A., et al., *Cost-Benefit Analysis for Hydropower Production in Water Distribution Networks by a Pump as Turbine.* Journal of Water Resources Planning and Management, 2014. **0**(0): p. 04014002.
29. Fontana, N., M. Giugni, and D. Portolano, *Losses Reduction and Energy Production in Water-Distribution Networks.* Journal of Water Resources Planning and Management, 2012. **138**(3): p. 237-244.
30. Wallace, A.R., *Embedded mini-hydro generation in the water supply industry*, in *IEE International Conference on Electric Power Generation*. 1996: Durham. p. 168-171.
31. Rentricity, *Rentricity Case Study: City of Keene Water Treatment Facility, New Hampshire*. 2012, Rentricity Inc.
32. Giugni, M., N. Fontana, and D. Portolano, *Energy Saving Policy in Water Distribution Networks*, in *International Conference on Renewable Energies and Power Quality (ICREPQ'09)*. 2009, European Association for the Development of Renewable Energies, Environment and Power Quality: Valencia (Spain).
33. Colombo, A. and Y. Kleiner, *Energy recovery in water distribution systems using microturbines*, in *Probabilistic Methodologies in Water and Wastewater Engineering (in Honour of Prof. Barry Adams, University of Toronto)*. 2011, NRC Construction: Toronto, Canada. p. 1-9.
34. Corcoran, L., P. Coughlan, and A. McNabola. *Energy Recovery Potential of the Dublin Region Water Supply Network*. in *Proceedings of the International Water Association World Congress on Water*. 2012. Dublin, Ireland.

35. Corcoran, L., P. Coughlan, and A. McNabola, *Energy recovery potential using micro hydro power in water supply networks in the UK & Ireland.* Water Science & Technology, 2013. **13**(2): p. pp 552-560.
36. Saket, R.K. *Design, development and reliability evaluation of micro hydro power generation system based on municipal waste water*. in *Electric Power Conference, 2008. EPEC 2008. IEEE Canada*. 2008.
37. EcoGeneration, *Powering Sydney Waters carbon nuetral future*, in *News article*. 2008.
38. Engineering & Technology, *Power generation by Archimedes screw*, in *Engineering & Technology*. 2010.
39. Griffin, F.M., *Feasibility of energy recovery from a wastewater treatment scheme.* Proceedings of the Institution of Mechanical Engineers, Part A: Journal of Power and Energy, 2000. **214**(1): p. 41-51.
40. Power, C., A. McNabola, and P. Coughlan, *Development of an evaluation method for hydropower energy recovery in wastewater treatment plants: Case studies in Ireland and the UK.* Sustainable Energy Technologies and Assessments, 2014. **7**(0): p. 166-177.
41. Eurostat *Urban-intermediate-rural regions*. Around 40% of the EU27 population live in urban regions… …and almost a quarter in rural regions, 2012.
42. Gössling, S., et al., *Food management in tourism: Reducing tourism's carbon 'foodprint'.* Tourism Management, 2011. **32**(3): p. 534-543.
43. UNEP, *Greening the Economy Through Life Cycle Thinking - Ten Years of the UNEP/SETAC Life Cycle Initiative*. 2012, United Nations Environment Programme.
44. Rothausen, S.G.S.A. and D. Conway, *Greenhouse-gas emissions from energy use in the water sector.* Nature Climate Change, 2011. **1**(4): p. 210-219.
45. Shrestha, E., et al., *The carbon footprint of water management policy options.* Energy Policy, 2012. **42**(0): p. 201-212.
46. Defra, *2012 Guidelines to Defra / DECC's GHG Conversion Factors for Company Reporting*. 2012, DEFRA, UK.
47. Griffiths-Sattenspiel, B. and W. Wislon, *The Carbon Footprint of Water. A River Network Report*. 2009, River Network.
48. Water UK *Sustainability Indicators 2010/11*. 2012.
49. Botto, S., et al., *Towards lower carbon footprint patterns of consumption: The case of drinking water in Italy.* Environmental Science & Policy, 2011. **14**(4): p. 388-395.
50. Qi, C. and N.-B. Chang, *Integrated carbon footprint and cost evaluation of a drinking water infrastructure system for screening expansion alternatives.* Journal of Cleaner Production, 2012. **27**(0): p. 51-63.
51. EA, *Renewable energy potential in water industry*. 2009, Environment Agency: Bristol.
52. Gausdal, A. and J. Hildrum, *Facilitating Trust Building in Networks: A Study from the Water Technology Industry.* Systemic Practice and Action Research, 2012. **25**(1): p. 15-38.
53. Coughlan, P. and D. Coghlan, *Reconciling market requirements and operations resources: an opportunity for action learning.* Action Learning: Research and Practice, 2009. **6**(2): p. 109-119.
54. AEA *2012 Guidelines to Defra / DECC's GHG Conversion Factors for Company Reporting*. 2012. **1.0**.
55. Dept. of Communications, E.a.N.R., *Renewable Energy Feed in Tariff 2012*. 2012.
56. OFGEM *Typical domestic energy consumption figures*. 2011.
57. Europe's Energy Portal. *Electricity Households*. 2012 [cited 2012 28th August]; Available from: http://www.energy.eu/.
58. Williamson, S.J., B.H. Stark, and J.D. Booker, *Low head pico hydro turbine selection using a multi-criteria analysis.* Renewable Energy, 2011(0).
59. Kumar, A., et al., *Hydropower*, in *IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation*, O. Edenhofer, et al., Editors. 2011, Cambridge University Press, : Cambridge, United Kingdom and New York, NY, USA. p. 60.
60. Teuteberg, B., ,, *Design of a Pump Microhydro System for an Abalone Farm*, in *Department of Mechanical and Mechatronic Engineering*. 2010, Stellenbosch University. p. 65.
61. Paish, O., *Small hydro power: technology and current status.* Renewable and Sustainable Energy Reviews, 2002. **6**(6): p. 537-556.
62. International Renewable Energy Agency, *Renewable Energy Technologies: Cost Analysis Series. Hydropower*, in *Renewable Energy Technologies: Cost Analysis Series*. 2012, IRENA: Germany. p. 1-44.
63. Aggidis, G.A., et al., *The costs of small-scale hydro power production: Impact on the development of existing potential.* Renewable Energy, 2010. **35**(12): p. 2632-2638.
64. Chae, K.-J. and J. Kang, *Estimating the energy independence of a municipal wastewater treatment plant incorporating green energy resources.* Energy Conversion and Management, 2013. **75**(0): p. 664-672.
65. Europe's Energy Portal. *Fuel Prices*. 2013 [cited 2013 February 22]; Available from: http://www.energy.eu/#domestic.
66. European Small Hydropower Association, *Guide on How to Develop a Small Hydropower Plant*. 2004. p. 1-296.
67. San Bruno, G., A. Choulot, and V. Denis, *Energy recovery in existing infrastructures with Small Hydropower Plants. Multipurpose schemes - Overview and Examples*. 2010, ESHA, SHAPES & Mhylab.
68. United States Environmental Protection Agency, *Renewable Energy Fact Sheet: Low-Head Hydropower from Wastewater*. 2013. p. 8.
69. Sargent, K.M., *Supporting Renewable Energy: Lessons from the Deer Island Treatment Plant*. 2010, Washington University: St. Louis, Missouri. p. 89.
70. Sustainable Energy Authority of Ireland. *Understanding Renewable Energy - FAQ's*. [cited 2012 February 28]; Available from: http://www.seai.ie/Renewables/Renewable_Energy_FAQ/.
71. Brander, M., et al., *Electricity-specific emission factors for grid electricity*. 2011, Ecometrica,. p. 22.
72. Central Statistics Office, *Population and Labour Force Projections 2016-2046*. 2013.
73. Fehily, B., *A review of and report on certain matters relating to Dublin City Council's Ringsend wastewater treatment plant* 2008. p. 66.
74. CDM, *Ringsend WwTW Extension Fact Sheet*. 2011.
75. CDM, *Ringsend Wastewater Treatment Works Extension Environmental Impact Statement*. 2012.
76. Maraun, D., T.J. Osborn, and N.P. Gillett, *United Kingdom daily precipitation intensity: improved early data, error estimates and an update from 2000 to 2006.* International Journal of Climatology, 2008. **28**(6): p. 833-842.
77. Dunn, R., et al., *Climate: Observations, projections and impacts*. 2011, Met Office: Devon, United Kingdom. p. 153.
78. Sweeney, J., et al., *Climate Change–Refining the Impacts for Ireland*. 2008, Environmental Protection Agency: Ireland. p. 177.
79. McGrath, R., R. Fealy, and T. Sheridan, *Recent Irish weather extremes and climate change.* 2011.
80. Ogayar, B., P.G. Vidal, and J.C. Hernandez, *Analysis of the cost for the refurbishment of small hydropower plants.* Renewable Energy, 2009. **34**(11): p. 2501-2509.
81. Krozer, Y., *Cost and benefit of renewable energy in the European Union.* Renewable Energy, 2013. **50**(0): p. 68-73.
82. International Energy Agency, *World Energy Outlook 2012*. 2012: Paris, France.

83. Clancy, M. and J. Scheer, *Energy Forecasts for Ireland to 2020. 2011 Report*. 2011, Sustainable Energy Authority of Ireland: Ireland. p. 74.
84. Howley, M., et al., *Energy in Ireland 1990 – 2011*. 2012, Sustainable Energy Authority of Ireland (SEAI),,: Ireland. p. 96.
85. Choulot, A., V. Denis, and P. Punys, *Integration of Small Hydro Turbines into Existing Water Infrastructures*, in *Hydropower - Practice and Application*, Hossein Samadi-Boroujeni, Editor. 2012.
86. Motwani, K.H., S.V. Jain, and R.N. Patel, *Cost Analysis of Pump as Turbine for Pico Hydropower Plants – A Case Study.* Procedia Engineering, 2013. **51**(0): p. 721-726.
87. Carravetta, A., et al., *PAT Design Strategy for Energy Recovery in Water Distribution Networks by Electrical Regulation.* Energies, 2013. **6**(1): p. 411-424.
88. Zeropex, *Pricelist for Difgen tubines*. 2014.
89. Ogayar, B. and P.G. Vidal, *Cost determination of the electro-mechanical equipment of a small hydro-power plant.* Renewable Energy, 2009. **34**(1): p. 6-13.
90. FXtop, *Inflation calculator*. 2014.
91. Georepository. *Datum: European Terrestrial Reference System 1989.* Geodetic Datum used in Europe - ETRS89 2014 [cited 2014 June]; Available from: http://www.euref-iag.net.
92. CSO, *Standard Report on Methods and Quality (v1) for Census of Population, 2006*, C.S. Office, Editor. 2009.
93. CSO, *Census 2011 Boundary Files*, C.S. Office, Editor. 2014.
94. CSO, *Census 2011 Small Area Population Statistics (SAPS)*, C.S. Office, Editor. 2014.
95. ONS, *2011 Census Data Catalogue (Version 16)*, O.f.N. Statistics, Editor. 2014.
96. ONS, *OA boundary data* O.f.N. Statistics, Editor. 2014.
97. ONS, *2011 Census Bulk Data Download (Release 2)*, O.f.N. Statistics, Editor. 2014.
98. EFGS, *GEOSTAT 1A – Representing Census data in a European population grid* E.F.f. GeoSstatistics, Editor. 2012.
99. Eurostat, *Population Distribution - Demography*, E.F.f. GeoStatistics, Editor. 2014.
100. Google Earth, *Getmapping plc 2014*. 2014.
101. McNabola, A., et al., *Energy recovery in the water & waste water industry using micro-hydropower: a review*, in *IASTED International Conference on Power and Energy Systems*. 2012: Naples, Italy. p. pp1-7.
102. EES Consulting, *City of Homer: Water Supply System Micro-Hydro Feasibility Study*. 2009.
103. Renewables First, *Introducing micro and small hydropower*. 2011, Renewables First.
104. Royal Geographical Society (with IBG), *Water policy in the UK - The challenges*. 2012, RGS-IBG Policy Briefing.
105. Northern Ireland Electricity, *Connection for small scale generation*. 2014.
106. SEAI, *A Report on Micro-Generation in Ireland*. 2010, Sustainable Energy Authority of Ireland.
107. SEAI, *Energy in the Residential Sector - 2013 Report*, E. Dennehy and M. Howley, Editors. 2013, Sustainable Energy Authority of Ireland.
108. DECC, *Sub-national electricity consumption statistics 2012 - Regional and local authority level statistics (2012 data)*, S. Khan and S. Stadnyk, Editors. 2013, Department of Energy & Climate Change.
109. SEAI, *Electricity & Gas Prices in Ireland. 2nd Semester (July - December) 2013*, M. Howley and M. Holland, Editors. 2014, Sustainable Energy Authority of Ireland.
110. SEAI, *Energy in Ireland: Key Statistics 2013*, M. Howley and M. Holland, Editors. 2013, Sustainable Energy Authority of Ireland.
111. Defra, *2013 GHG conversion factors for company reporting: methodology paper for emission factors*. 2013, DEFRA, UK.
112. DECC, *Sub-regional Feed-in Tariffs confirmed on the CFR statistics*. 2013, Department of Energy & Climate Change.
113. IRENA, *Renewable Energy Technologies: Cost Analysis Series*. 2012, International Renewable Energy Agency.
114. BHA, *A Guide to UK Mini-Hydro Developments*. 2005, The British Hydropower Association.
115. Zeropex, *Pen y Cefn Water Treatment Works - Difgen Turbine Installation*, I. Goddard, Editor. 2013.
116. McNabola, A., P. Coughlan, and A.P. Williams, *Energy recovery in the water industry: an assessment of the potential of micro-hydropower.* Water and Environment Journal, 2014. **28**(2): p. 294–304.
117. Electric Ireland, *Micro-generation Scheme*. 2014.
118. OFGEM, *Feed-in Tariff Payment Rate Table for Non-Photovoltaic Eligible Installations for FIT Year 5 (1 April 2014 to 31 March 2015)*.
119. BSI, *PAS 2050:2011 Specification for the assessment of the life cycle greenhouse gas emissions of goods and services*. 2011, British Standards Institution.
120. Guezuraga, B., R. Zauner, and W. Pölz, *Life cycle assessment of two different 2 MW class wind turbines.* Renewable Energy, 2012. **37**(1): p. 37-44.
121. Raadal, H.L., et al., *Life cycle greenhouse gas (GHG) emissions from the generation of wind and hydro power.* Renewable and Sustainable Energy Reviews, 2011. **15**(7): p. 3417-3422.
122. Rule, B.M., Z.J. Worth, and C.A. Boyle, *Comparison of life cycle carbon dioxide emissions and embodied energy in four renewable electricity generation technologies in New Zealand.* Environ Sci Technol, 2009. **43**(16): p. 6406-13.
123. Pascale, A., T. Urmee, and A. Moore, *Life cycle assessment of a community hydroelectric power system in rural Thailand.* Renewable Energy, 2011. **36**(11): p. 2799-2808.
124. UKWIR, *Carbon accounting in the UK water industry: guidelines for dealing with embodied carbon and whole life costing*. 2008, UK Water Industry Research.
125. Donnelly, C.R., et al., *An assessment of the life cycle costs and GHG emissions for alternative generation technologies*, in *World Energy Congress*. 2010: Montréal, Canada.
126. Gagnon, L. and J.F. van de Vate, *Greenhouse gas emissions from hydropower: The state of research in 1996.* Energy Policy, 1997. **25**(1): p. 7-13.
127. CML, *Characterisation Factors database available online from Institute of Environmental Sciences (CML)*. 2010, Universiteit Leiden, Leiden, 2010.
128. Goedkoop, M., et al., *SimaPro Database Manual - Methods library*. 2008, Pré Consultants: The Netherlands.
129. Flury, K. and R. Frischknecht, *Life cycle inventories of hydroelectric power generation*. 2012, Öko-Institute e.V.
130. Bonton, A., et al., *Comparative life cycle assessment of water treatment plants.* Desalination, 2012. **284**(0): p. 42-54.
131. Goedkoop, M. and R. Spriensma, *The Eco-indicator 99 - A damage oriented method for Life Cycle Impact Assessment*, A. PRe Consultants B.V., Editor. 2001, Ministerie van Volkshuisvesting Ruintelijke Ordening en Milieubeheer: Publikatereeks Produktenbeleid 1999/36a.
132. DECC, *Electricity Generation Costs*. 2012, Department of Energy & Climate Change.
133. Dŵr Cymru Welsh Water, *Strata Florida Water Treatment Works - Hydro Scheme*, M.P.A. Fairman, Editor. 2013.

134. Fleming, N., *Vartry Reservoir and Water Treatment Works - Vartry Hydro Scheme*. 2013: Dublin City Council.
135. Ecoinvent, *Ecoinvent database version 3*, a.v. SimaPro, Editor. 2014.
136. D'Souza, N., E. Gbegbaje-Das, and P. Shonfield, *Life Cycle Assessment of Electricity Production from a V112 Turbine Wind Plant*, P. NWE, Editor. 2011, Vestas Wind Systems A/S: Denmark.
137. Varun, R. Prakash, and I.K. Bhat, *Energy, economics and environmental impacts of renewable energy systems.* Renewable and Sustainable Energy Reviews, 2009. **13**(9): p. 2716-2721.
138. Suwanit, W. and S. Gheewala, *Life cycle assessment of mini-hydropower plants in Thailand.* The International Journal of Life Cycle Assessment, 2011. **16**(9): p. 849-858.
139. ISO, *ISO 14040: environmental management - life cycle assessment - principles and framework*. 2006, ISO, Geneva.
140. Cellura, M., S. Longo, and M. Mistretta, *Sensitivity analysis to quantify uncertainty in life cycle assessment: the case study of an Italian tile.* Renewable and Sustainable Energy Reviews, 2011. **15**(9): p. 4697-4705.
141. Sleeswijk, A.W., et al., *Normalisation in product life cycle assessment: an LCA of the global and european economic systems in the year 2000.* Science of The Total Environment, 2008. **390**(1): p. 227-240.
142. Lim, S.-R., D. Park, and J.M. Park, *Analysis of effects of an objective function on environmental and economic performance of a water network system using life cycle assessment and life cycle costing methods.* Chemical Engineering Journal, 2008. **144**(3): p. 368-378.
143. Sala, S., et al., *Research needs and challenges from science to decision support. Lesson learnt from the development of the international reference life cycle data system (ILCD) recommendations for life cycle impact assessment.* Sustainability, 2012. **4**(7): p. 1412-1425.
144. Basbagill, J., et al., *Application of life-cycle assessment to early stage building design for reduced embodied environmental impacts.* Building and Environment, 2013. **60**(0): p. 81-92.
145. Gallagher, J., et al., *A strategic assessment of micro-hydropower in the UK and Irish water industry: identifying technical and economic constraints.* Renewable Energy, 2015. **81**(0): p. 808-815.
146. DoECLG, *Water Services*. 2013, Department of the Environment, Community and Local Government.
147. Welsh Assembly, *Inquiry into Energy Policy and Planning in Wales*, E.a.S. Committee, Editor. 2011.
148. Dŵr Cymru Welsh Water, *Dŵr Cymru Welsh Water: Our Sustainable Future*. 2007, Dŵr Cymru Welsh Water.
149. Corcoran, M., *Our Good Health: A history of Dublin's water and drainage*. 2005, Dublin City Council.
150. Nyström, H., *Product Development Strategy: An Integration of Technology and Marketing.* Journal of Product Innovation Management, 1985. **2**(1): p. 25-33.
151. Gehani, R.R., *Concurrent product development for fast-track corporations.* Long Range Planning, 1992. **25**(6): p. 40-47.
152. Verganti, R., *Design, Meanings, and Radical Innovation: A Metamodel and a Research Agenda*.* Journal of Product Innovation Management, 2008. **25**(5): p. 436-456.
153. Brown, R.R. and M.A. Farrelly, *Delivering sustainable urban water management: a review of the hurdles we face.* Water Sci Technol, 2009. **59**(5): p. 839-46.
154. Jalba, D.I., et al., *Effective drinking water collaborations are not accidental: interagency relationships in the international water utility sector.* Sci Total Environ, 2014. **470-471**: p. 934-44.
155. Taylor, A.C., *Sustainable urban water management: understanding and fostering champions of change.* Water Sci Technol, 2009. **59**(5): p. 883-91.
156. Wheelwright, S.C. and K.B. Clark, *Revolutionizing Product Development: Quantum Leaps in Speed, Efficiency, and Quality*. 1992: Free PRess. p. Chapter 2.
157. LGMA, *Service Indicators in Local Authorities 2012*. 2014, Local Government Management Agency: Dublin.
158. DCC, *The Plan- Demand Appendix, Water Supply Project- Dublin Region*. 2010, Dublin City Council: Dublin.
159. Irish Water, *Water Service Strategic Plan - Issues Paper*. 2014: Dublin.
160. !!! INVALID CITATION !!! {}.
161. CSO, *This is Ireland. Highlights from census 2011, part 1*. 2012, Central Statistics Office: Dublin.
162. Met Eireann, *Rainfall in Ireland*. 2014.
163. Sweeney, J., et al., *Climate Change – Refining the Impacts for Ireland*. 2008.
164. Corcoran, L., A. McNabola, and P. Coughlan, *The optimization of water distribution networks for combined hydropower energy recovery and leakage reduction.* 2015.
165. Power, C., P. Coughlan, and A. McNabola, *The applicatility of hydropower technology in waste water treatment plants*, in *Proceedings of the International Water Association World Congress on Water, Climate and Energy*. 2012: Dublin, Ireland.
166. Ørke, P. *Zeropex: Pressure control with a payback*. in *All Energy Exhibition and Conference 2010*. 2010.
167. Eurostat, *Hydropower.* 2014.
168. Nautiyal, H. and K.A. Varun, *CFD analysis on pumps working as turbines*. 2010, Hydro Nepal.
169. Koch, H., et al., *Security of Water Supply and Electricity Production: Aspects of Integrated Management.* Water Resources Management, 2014. **28**(6): p. 1767-1780.
170. Verganti, R., *Planned Flexibility: Linking Anticipation and Reaction in Product Development Projects.* Journal of Product Innovation Management, 1999. **16**(4): p. 363-376.

Appendices

Appendix A
Project Publications

Journal Publications (13):

J1. Power, C., Coughlan, P., McNabola, A., Development of an evaluation method for hydropower energy recovery in wastewater treatment plants: Case studies in Ireland and the UK, *Sustainable Energy Technologies & Assessment*s, 7, 2014, p166 – 177.

J2. McNabola, A., Coughlan, P., Corcoran, L., Power, C., Williams. A.P., Harris, I., Gallagher, J., Styles D., Energy Recovery in the Water Industry using Micro-hydropower: An Opportunity to Improve Sustainability, *Water Policy*, 16, 2014, p168 - 183.

J3. Corcoran, L., Coughlan, P., McNabola, A., Innovation and the Water Industry: Case studies of innovation, education and collaboration, *TCD Journal of Postgraduate Research*, 11, 2014.

J4. McNabola, A., Williams. A.P., Coughlan, P., Energy Recovery in the Water Industry: An Assessment of the Potential of Micro Hydropower, *Water and Environment Journal*, 28, 2014, p294 - 304.

J5. Corcoran, L., Coughlan, P., McNabola, A. Energy Recovery Potential using Micro Hydro Power in Water Supply Networks in the UK & Ireland. *Water Science & Technology: Water Supply*, 13, (2), 2013, p552 - 560.

J6. Gallagher J, McNabola A, Styles D, Williams AP., Life Cycle Environmental Balance and Greenhouse Gas Mitigation Potential of Micro-hydropower Energy Recovery in the Water Industry, *Journal of Cleaner Production*, 2015, In press

J7. Gallagher J, Harris IM, Packwood AJ, McNabola A, Williams AP., A strategic assessment of micro-hydropower in the UK and Irish water industry: identifying technical and economic constraints, *Renewable Energy*, 2015, 81, p808-815.

J8. Gallagher, J., Styles, D., McNabola, A., Williams, A.P., Current and future environmental balance of small scale run-of-river hydropower, *Environmental Science and Technology*, 2015, In press.

J9. Corcoran, L., McNabola, A., Coughlan P., The optimization of water distribution networks for combined hydropower energy recovery and leakage reduction, *Journal of Water Resource Planning and Management*, 2015, In press.

J10. Gallagher, J., Styles, D., McNabola, A., Williams, A.P., Making green technology greener: achieving a balance between carbon and resource savings through ecodesign in hydropower systems. *Resources, Conservation and Recycling*, 2015 (submitted).

J11. Corcoran, L., McNabola, A., Coughlan, P. The effect of variations in long-term water demand on micro-hydropower energy recovery in water supply networks. *Water Resources Management* 2015 (submitted).

J12. Brady, J., Gallagher, J., Corcoran, Coughlan, P., McNabola, A. The Impact of Long-Term Flow Variation and Climate Change on Micro-Hydropower Turbine Efficiency in Water Supply Networks. *Water Resources Management* 2015 (submitted).

J13. Gallagher, J., Styles, D., McNabola, A., Williams, A.P., Inventory compilation for renewable energy systems: the pitfalls of materiality thresholds and priority impact categories. *International Journal of Life Cycle Assessment*, 2015 (submitted).

Conference Publications (21):

C1. Lydon, T., Coughlan, P., McNabola, A. Energy Efficiency of Water: Analysis Pumps-as-Turbines to Recover Energy in Distribution Networks. *Water Ideas 2014, 22-24 October, Bologna Italy*. pp1-8.

C2. Corcoran, L., Coughlan, P., McNabola, A., Optimisation Of Water Supply For Combined Leakage Reduction And Hydropower Energy Generation, *IWA World Water Congress & Exhibition*, *Lisbon*, *21st-26th September*, 2014.

C3. McNabola, A., Brady, J., Coughlan, P., Gallagher, J., Williams, A.P. Improving Energy Efficiency in Water Infrastructure using Micro-hydropower Energy Recovery: Opportunities & Challenges, *2nd International Symposium on Energy Challenges and Mechanics*, *Aberdeen, UK*, *19-21st August*, edited by H, Tan , 2014, pp1-8.

C4. Gallagher, J., Styles, Williams, A.P. Assessing the Environmental Impacts of Micro-hydropower in the Water Industry, *ENVIRON 2014 Conference*, Trinity College Dublin, Ireland, 26-28th Feb, 2014.

C5. Lydon, T., Coughlan, P., McNabola, A. Energy Efficiency of Water: Analysis of Pumps-as-turbines Replacing Pressure Reducing Valves in Distribution Networks, *ENVIRON 2014 Conference*, Trinity College Dublin, Ireland, 26-28th Feb, 2014.

C6. Coughlan, P., Gallagher, J., Styles, D., Williams, A.P., McNabola, A. Operations improvement through energy recovery in water supply and treatment: assessing the potential for improved environmental sustainability. *20th International EurOMA Conference*, 7-12th June 2013, Dublin Ireland. *Operations Management at the Heart of the Recovery*, *Dublin, Ireland*, *7th-12th June*, edited by B. Fynes & P. Coughlan , 2013, pp121-121 .

C7. Gallagher, J., Styles, D., Harris, I.M., Packwood, A., Williams, A.P. Life Cycle Energy and Environmental Balance of Micro-Hydro Turbines in the Water Industry - An Ireland-Wales Context, *ENVIRON 2013 Conference*, NUI Galway, Ireland, 30th Jan - 1st Feb, 2013.

C8. Gallagher, J., Williams, A.P., Styles, D., Harris, I.M., Packwood, A.J., Coughlan, P., Power, C., Corcoran, L., McNabola, A. Energy Recovery in the Water Industry: A Technical, Economic and Commercial Feasibility Study in Ireland and Wales, *SPI Water Conference*, Brussels, Belgium, 3rd & 4th December, 2012.

C9. Corcoran, L., Coughlan, P., McNabola, A., Energy Recovery Potential within Water Supply Networks of Ireland using Micro-Hydropower Turbines: Analysis of Case Studies, *The 9th International Symposium on Water Supply Technology*, Yokohama, Japan, 20-22nd November, International Water Association, 2012, pp1-7.

C10. McNabola, A., Coughlan, P., Corcoran, L., Power C., Williams, A.P., Harris, I.M., Taylor R., Packwood, A., Energy Recovery in the Water & Waste Water Industry using Micro-Hydropower: A Review., *IASTED International Conference on Power and Energy Systems, Naples, Italy*, 25th-27th June, edited by J.P.S Catalao, 2012, pp40 - 46.

C11. Power, C., McNabola, A. & Coughlan, P., The Applicability of Hydropower Technology in Wastewater Treatment Plants, *International Water Association: World Congress on Water, Climate & Energy*, *Dublin, Ireland*, *May 13-18 2012*, 2012

C12. Corcoran, L., McNabola, A., & Coughlan P., Energy Recovery Potential of the Dublin Region Water Supply Network, *International Water Association: World Congress on Water*, *Dublin, Ireland*, *May 13-18 2012*, 2012

C13. McNabola, A., Williams. A.P., Coughlan, P., The Technical & Economic Feasibility of Energy Recovery in Water Supply Networks, *International Conference on Renewable Energy and Power Quality, Las Palmas de Gran Canaria, 13th - 15th April*, edited by Perez-Donsion, M. , 2011, pp1-5

C14. L. Corcoran, C. Power, A. McNabola, P. Coughlan, 2011. Investigating of the Technical and Commercial Feasibility of Energy Recovery in the Water Industry. Dublin Region Higher Education Alliance, Future Voices Competition, Dublin Castle.

C15. Gallagher, J., Styles, D., Williams, A.P., McNabola, A., Quantifying the Environmental Impact of Micro-hydropower in the water industry using Life Cycle Assessment, [anviR] Conference: Life Cycle in Practice, Lille, 5-6th November, 2014.

C16. Brady, J., Patil, S., McNabola, A., Gallagher, J., Coughlan, P., Harris, I., Packwood, A., Williams, P. An assessment of climate change impacts on micro-hydropower energy recovery in water supply networks, European Geosciences Union General Assembly, Vienna, 12-17th April, 2015.

C17. Power, C., Coughlan, P., McNabola, A. , A Parametric Experimental Investigation of the Operating Conditions of Gravitational Vortex Hydropower (GVHP), Journal Conference on Clean Energy Technology, Florence, Italy, 19th & 20th March, 2015, pp1-8.

C18. Lydon, T., Coughlan, P., McNabola, A., Pump-as-turbine: Testing and characterisation as an energy recovery device, for use within the water distribution network., ICWEEM 2015: XIII International Conference on Water, Energy and Environmental Management, Madrid, Spain, 26-27 March, 2015, pp1-8

C19. Gallagher J. Promoting ecodesign in hydropower projects: being greener than green British Hydropower Association, Summer Forum & Exhibition. June 2015.

C20. Gallagher J., Styles D., Brady, J., McNabola, A., Williams, A.P. From treatment to tap: the future for micro-hydropower installations in water infrastructure as climate change impacts on our water resources. IWRA World Water Congress XV Conference. Edinburgh, Scotland, 25th-29th May 2015.

C21. Gallagher J., McNabola A., Styles D., Williams A.P., Harris I., Coughlan P., Power C., Corcoran L. The HydroBPT Project: Realising the true potential for energy recovery in the water industry in Ireland and Wales. *Environ 2013, 23rd Environmental Researcher's Colloquium.* NUI Galway. 30th Jan – 1st Feb.

SOUTHERN & EASTERN
Regional Assembly
Promoting Our Region

IRELAND WALES
2007 – 2013

Ireland's EU Structural Funds
Programmes 2007 - 2013

Co-funded by the Irish Government
and the European Union

EUROPEAN REGIONAL
DEVELOPMENT FUND