Department of Mechanical and Aerospace Engineering

Retrofit Potential for Increased Efficiency and/or Output of the Galloway Hydros

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A thesis submitted in partial fulfilment for the requirement of the degree
Master of Science
Sustainable Engineering: Renewable Energy Systems and the Environment
2018

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Abstract

It is estimated that by 2030 the need for energy storage is set to triple, and with the current installed hydro storage taking up approximately 96% of the total storage, major renovations of existing hydropower plants are a cost-effective way to increase efficiencies. As a result, this dissertation investigates the retrofit potential for the Scottish Power owned Galloway Hydro-Electric Power Scheme that would improve the efficiency and/or output of the plant.

In part an extensive literature review has been conducted on the individual areas and components, apparent in the Galloway Hydros, that were found in literature and in case studies, to be subject to an efficiency or output enhancement. A site visit was conducted to test the viability of the solutions found in the literature.

Scope for selected potential solutions found during the site visit was taken forward for a technical analysis as well as for a practical and economic feasibility study. Potential solutions selected for further review were the retrofit potential for an adjustable pitch Kaplan turbine and modernisation of the Francis turbines on site.

It was concluded that retrofitting of an adjustable pitched Kaplan turbine into either the Carsfad, Earlstoun or Drumjohn could be valuable and economically feasible, depending on the average availability of the rated flow. Modernisation through retrofit of the Francis turbines on site are found to increase the efficiency and output of the currently installed turbines, using Glenlee power station as a case study. Yet it was proven in a cost-benefit analysis not to be economically feasible over a 30-year period due to the high up-front costs.

The workings of this project should provide Scottish Power support in future decisions in regard to retrofits at the Galloway Hydros - that have the aim of improving the efficiency or output of the plant. On a wider scope, this project has provided empirical calculations, potential solutions, and methodology that are valuable to hydropower plants considering uprating - allowing them to stay competitive as the energy transition to more sustainable energy resources continues.

Acknowledgements

I would foremost like to thank my supervisor Dr Nicolas Kelly from the Mechanical and Aerospace Department at the University of Strathclyde for his helpful comments and support he has given to me throughout this work. On top of that, I would also like to thank course director Paul Tuohy for his advice and support throughout the duration of the course, especially during the undertaken of the dissertation.

Furthermore, I would like to thank especially Ian Kinnaird and Carlo Lummi from Scottish Power, for introducing me to the world of hydropower and for their helpful thoughts, supplying of critical data, as well as for showing me around the site. Without the support you have given me, this project would not be possible.

I would also like to take this opportunity to say a big thank you to the Scottish Power Foundation for sponsoring me throughout the entirety of the course. Due to their support, I have been able to undertake this game-changing course and have had the opportunity to pursue my passion for sustainable engineering.

Last but not least, I would like to say thank you to my family and friends for all their support and encouragement over the duration of this project.

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Section I – General

1.1 - Introduction

With the increasing concern of climate change, an energy transition towards more sustainable and environmentally friendly energy sources is currently underway. In this energy transition away from fossil-fuelled energy sources, a means of electrical storage is essential to combat the stochastic nature of renewable energy systems. Hydroelectric storage as the largest form of grid-connected storage, and the most mature storage technology will play a critical role in this energy transition; with its ability to absorb excess energy and to balance peaks and troughs in electrical demand. Hydropower, on the other hand, is the current global leader in renewable electricity production, offering flexible generation, that can be turned on and off when required, and a low-cost base-load power (World Energy Council, 2016). As the sector moves towards decarbonisation, flexible energy sources will have to be developed and renovated in order to meet the new evolving roles required of it from the penetration of renewable energy sources (IRENA, 2017).

It is estimated that by 2030 the need for energy storage is set to triple, and with the current installed hydro storage taking up approximately 96% of the total storage, major renovations of existing hydropower plants are a cost-effective way to increase efficiencies (IRENA, 2017). Technological developments in recent years allow potential retrofitting to existing systems, that can improve their performance and flexibility, as well as, reducing their environmental impact (World Energy Council, 2016). Furthermore, with the rapid development of improved performance and falling costs of battery electrical storage, retrofits of existing hydropower plants are necessary to stay competitive with new storage technologies. Retrofitting is also more widely accepted publicly, rather than the instalment of new hydropower plants, as it requires little construction and disturbance to the existing plant.

With these benefits, potential retrofit solutions should be considered for existing hydropower plants. Hence, this project will aim to investigate potential solutions for a proposed site. The site chosen to be investigated for potential retrofit solutions is the Galloway Hydros; the first installed large-scale integrated hydro-electric plant, commissioned in the 1930s. If successful, the retrofit solutions provided, to increase the output of the Galloway Hydros, could be further applied in other hydro plant locations. Additionally, the literature review of the currently installed solutions should bring readers up to date with the latest renovations occurring at hydro plants.

1.2 - Aim

- To investigate existing successful retrofit solutions of hydropower plants that have improved their efficiency and/or output and to determine their suitability for the Galloway Hydros.
- Propose potential retrofit solutions for the Galloway Hydros, based on site-specific data and key literature.
- Determine the feasibility of the proposed retrofit solutions, through analysis, based on the economics, the retrofit process, and the potential impacts.

1.3 - Methodology

This dissertation is aimed at providing an extensive investigation into possible retrofit options that could increase the output and/ or the efficiency of the Galloway Hydros. Success of the project will rely on the liaison with Scottish Power, for successful data gathering and to confirm the viability of solutions in industry.

The structure of this project consists of first undertaking an initial review of the Galloway Hydros, hydropower and the motivations for retrofit, to give context to the preceding chapters. An extensive literature review will follow, with the aim to investigate previous successful retrofit solutions, and to develop a solid foundation of knowledge on the topic, in order to suggest possible retrofit options specific to the site. The literature review will focus in on four main areas of the plant and will detail the components associated with them that have been identified as possessing the potential for improving the efficiency and/ or the output. The literature review will also highlight approaches and indicators that are found in literature when considering increasing the efficiency or output of the plant.

To further support the proposal of possible solutions a site visit will be conducted, which will consist of meeting onsite staff and visiting the associated hydropower plants to scope out the project, and further understand the system in order to test the validity of the solutions found in literature.

As a result of the steps above, selected possible solutions specific to the Galloway Hydros will be proposed and discussed in detail. In part, a technical analysis will be undertaken to determine the performance benefits associated, as well as a feasibility study on the economics, by means of a cost-benefit analysis, the practicality of the retrofit and the potential impacts associated to each proposed solution.

Conclusions will then be drawn from the appraisal of each solution where recommendations can be made to Scottish Power. Any further solutions found will be proposed in the future work section, which will conclude the report.

Section II- Background

2.1 - Overview of the Galloway Hydros

Located in Galloway, South Ayrshire, the Galloway Hydro-Electric Scheme, GHES, consists of six power stations, integrated across eight dams, and was first established in the mid-1930's with the objective to manage peak loads. With the capability of powering approximately 58,000 homes, all of the six power stations are remotely controlled from the Glenlee power station and have a combined capacity of 104 MW. The GHES operates through strategically controlling the water through each of the eight dams and six power stations as the water moves from the north in Loch Doon down towards the Salway Firth - located close to the Tongland power station. The Earlstoun, Tongland, Carsfad and Kendoon Dams, which have a combined average storage capacity of 4.04 million m^3, act as daily storage and are key in managing the operational patterns. Loch Doon and Clatteringshaws reservoir, on the other hand, are key to managing long-term seasonal storage due to their larger capacities, where during the summer months are depleted and refilled during the winter months; this also acts as a method in flood management. Operating engineers at the site undergo forecasting of the available water which is available through weather reports and rain gauges, operate accordingly through the opening and closing of sluice gates to manually control the water levels.

The following sections will briefly introduce each of the hydropower plants, HPPs, located on the GHES, with the aim to construct a background for the literature review and technical analysis to build upon. Parameters stated in the following section are taken from the "Galloway Hydros Technical Factsheet", made available online, all other parameters are taken from internal documentation (Scottish Power, 2010, 2018b).

2.1.1 - Drumjohn Power Station

The northernmost power station, and with the lowest average net head out of all six power stations is Drumjohn. Connected via a 2.4m diameter and 1942m long tunnel, Drumjohn power station retrieves water from Loch Doon at an average net heat of 13m, to produce its 2.25MW of electrical power. The last of the power stations in the scheme to be built, Drumjohn power station contrives of a single horizontal Kaplan turbine, which utilizes the previously released water from the needle valve. The outflowing water flows into the Kendoon reservoir, later used by the Kendoon power station. Drumjohn is one of three power stations that are subject to the Renewable Obligation subsidy.

2.1.2 - Kendoon Power Station

Located 45m below Drumjohn power station is the Kendoon power station, the third largest of the six power stations, with a combined capacity of 21MW. The power station is fueled from Loch Doon, the largest of the storage reservoirs of the Galloways Hydros, and has an average head of 46m. Electricity is produced at the station through the instalment of two Francis vertical reaction turbines and two 10.5MW conventional field design generators. At Kendoon reservoir a 35m high surge tank is installed that powers the turbines and also protects the penstocks. The catchment area for the station is approximately 394 km^2, and at full load can intake 53 m^3/sec. The water for Kendoon is retrieved from a canal that draws off water from the reservoir.

Figure 1: Kendoon Power Station

2.1.3 - Carsfad Power Station

Located just south of Kendoon, Carsfad power station generates 12MW through its 2 vertical Kaplan turbines. The objective of the power station is to provide storage for the meeting of daily operation patterns. Commissioned in 1936 the station takes it water from the Carsfad pond, formed by the longest of the dams in the scheme at 503m long and 21m high; the pond is mostly filled from the discharge of the Kendoon power station. Through this capacity, the station can maintain full station load for 75 minutes at a head of 20m, 74m ^{3}/sec, and in worst case scenarios, the reservoir can be taken down to a height of 2.5m (William, Eng and E, 1938). The HPP over the past 20 years has produced an average of 11751MWh/year.

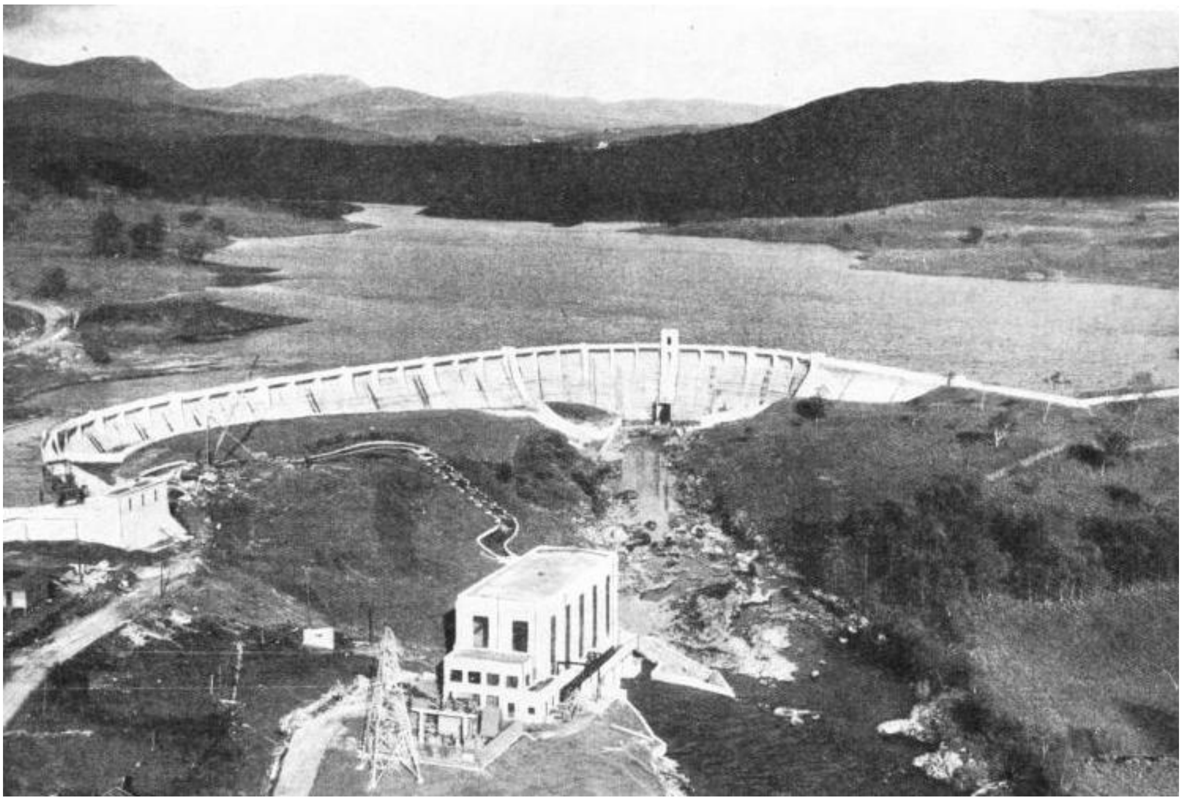

Figure 2: Carsfad Power Station & Dam (Wondersofworldengineering, 2014)

2.1.4 - Earlstoun Power Station

Very similar to the Carsfad power station is the Earlstoun power station, which operates at the same capacity with again two vertical Kaplan turbines. Located only a mile and a half from the Glenlee power station, the station gets it water from the 1m^3 pond located between the Carsfad power station and the Earlstoun Dam at 20m high.

2.1.5 - Glenlee Power Station

In terms of generating capacity, Glenlee is the second highest in the scheme with a combined capacity of 24MW through the use of two 12MW Francis turbines. The station is reliant on the water from the 35m^3 Clatteringshaws loch located 116m above the station; it has more than triple the head of any next highest station in the scheme. The station is connected via a 5791m long tunnel with an average diameter of 3.35m, with the water discharging from the station into Loch Ken. With such capacity from Clatteringshaws Loch, the station can run at full load for approximately 17 days straight. Glenlee power station plays an important role in the scheme in the controlling and operating of all other stations in the scheme, through the use of a SCADA system. Glenlee does not fall under the ROC subsidy due to its combined capacity being over 10MW.

Figure 3: Galloway Hydro Electric Scheme (Scottish Power, 2010)

2.1.6 - Tongland Power Station

Located close to the Solway Firth and at the end of the GHES is the Tongland power station. The station has the largest capacity of all the plants on the scheme at 33MW, while also close to double the next largest catchment area of any station, at 1.023km^2. Operating at a head of 32m, the Tongland power station consist of three Francis turbines, powering 11MW generators. The station retrieves the water from Loch Ken, which is being continuously fed into by all the remaining stations - dammed by the Tongland Dam at 296m wide and 22m long. The role of the dam and station is to provide seasonal storage for the continued meeting of daily operations. A 1199m long tunnel of a large 6.1m diameter supplies the water to the station.

2.2 - Hydropower

In this section, the operation and make up of hydropower stations will be detailed, allowing the reader to have a full understanding of the renewable energy source prior to detailed description of potential solutions described in the literature. Nevertheless, the description will be in reference to the hydropower makeup at the GHES and consequently will not go into detail of areas not apparent in the scheme.

Hydropower on the GHES is classed as both run of the river and storage type hydropower, due to the operation of the plant and its method of utilizing the flow between stations for power generation. Run of the river, traditionally uses the flow of the river to generate electricity, either directly or through an up-stream diversion of the river, however, at the GHES storage is used to strategically control the flow of water as it makes it way to the sea. Hydro storage consists of damming the river to build up a great amount of storage, as well as the head, where power stations are normally located close to the dam. When power is required water flows from the dam via a penstock to the power station where it can quickly generate electricity.

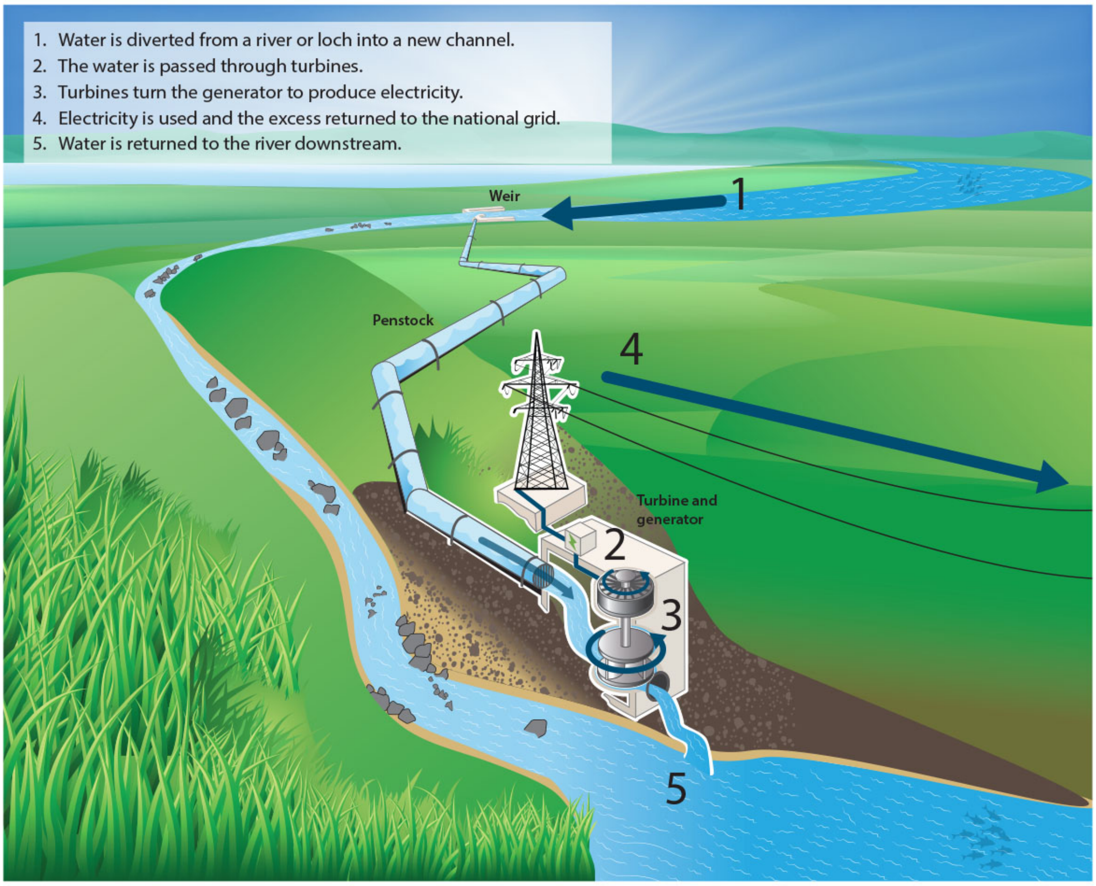

Figure 4: Run of the River Hydropower Scheme (SEPA, 2018)

In regard to the basic operation of an HPP, starting from the reservoir to the outflow, water is taken in from the dammed reservoir and into the penstock, which it then travels into the power station, striking the turbine, and powering the generator. This then produces electricity which is then transformed and sent via the power lines to meet demand, while the water is exited through the draft tube into the river below.

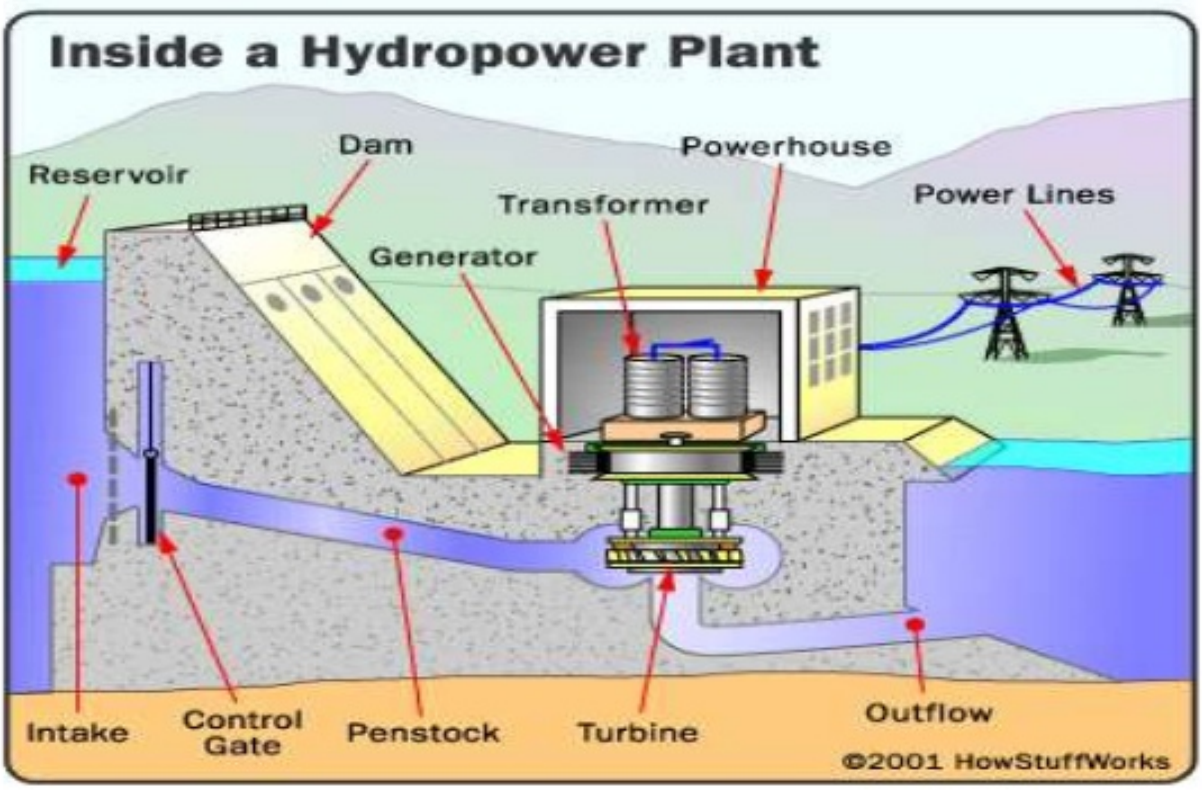

Figure 5: Basic Operation of a Hydropower Plant (Bonsor, 2018)

Civil structures at an HPP also include fish ladders, spillways, trash racks, surge tanks, floodgates, aqueducts, shutoff valves and the dam itself. At the GHES, fish ladders are installed at Tongland, Earlstoun, Carsfad and Loch Doon reservoirs, which aim to provide the native fish species, especially salmon, a method of avoiding the barriers of the dam and to enable migration (Scottish Power, 2018a). Surge towers are installed throughout the scheme, with the largest being at Kendoon power station, with the goal of protecting the turbines and pipelines from sudden changes in pressure (Scottish Power, 2010). Trash racks are also installed throughout the scheme and have the role of preventing any debris or material that can damage the turbines in the penstock. Shut off valves are installed at the far end of the penstock and allow water to be shut off from the turbine, enabling further control of the plant - especially in emergency situations and during maintenance. Floodgates and spillways, in periods of flooding, carry away any excess water from the dam.

At the GHES two main types of turbines are used, Francis and Kaplan. Both turbines are of the reaction type meaning that they utilize newtons third law of motion by creating torque from the striking of water (Darling, 2016). Reaction turbines are also fully submerged in water where the rotating of the turbine is achieved through the pressure difference across the runner vanes. Difference in application of the turbines depend on the head and type of flow, where Kaplan turbines are normally used for heads between 3m and 60m inflows up to 50m/s, and Francis turbines are normally used in higher heads up to 350m, although they normally don't exceed flow rates over 25 m/s.

The key component of the Francis turbine is the runner, which uses lift and impulse force to generate rotation. The runner is connected to the main shaft which is linked to the generator for power generation and is fitted within a spiral case. Water enters from the penstock via the inlet nozzle, and into the spiral case, where with its round shape evenly distributes the water. Connected to the spiral case is the stay and guide vanes which guide the water into the turbine. The stay vanes reduce the swirl of inlet flow and push the water towards the runner, while guide vanes are used to control the flow rate in respect to the power demand, as well as the adjust the flow angle to improve the efficiency. Guide vanes are controlled by the guide vane mechanism, which operates through the high-pressure oil supplied from the governor that moves the servomotors, which through the use of pins and arms, adjusts the guide vanes to the desired angle of attack. Draft tubes are fitted on the outlet, to reduce cavitation, maintain correct pressure and exit the water. Other components of the Francis turbine include the guide bearing, which supported through the head cover, acts as a method to maintain the turbine runner in its position by withstanding mechanical loading, and the stay ring which acts as a base for the guide vanes (Mesa Associates Inc. and Oak Ridge National Laboratory, 2011a). For point of reference, the upper part of the runner is called the upper ring and is connected to the blades by the runner crown (seal), and the lower part is called the lower ring and is connected to the blades by the runner band (seal). The point where the water leaves the blades of the runner is called the runner bucket and is located below the upper ring. Seal rings are used between the runner crown and the head cover to reduce water leakage through the turbine.

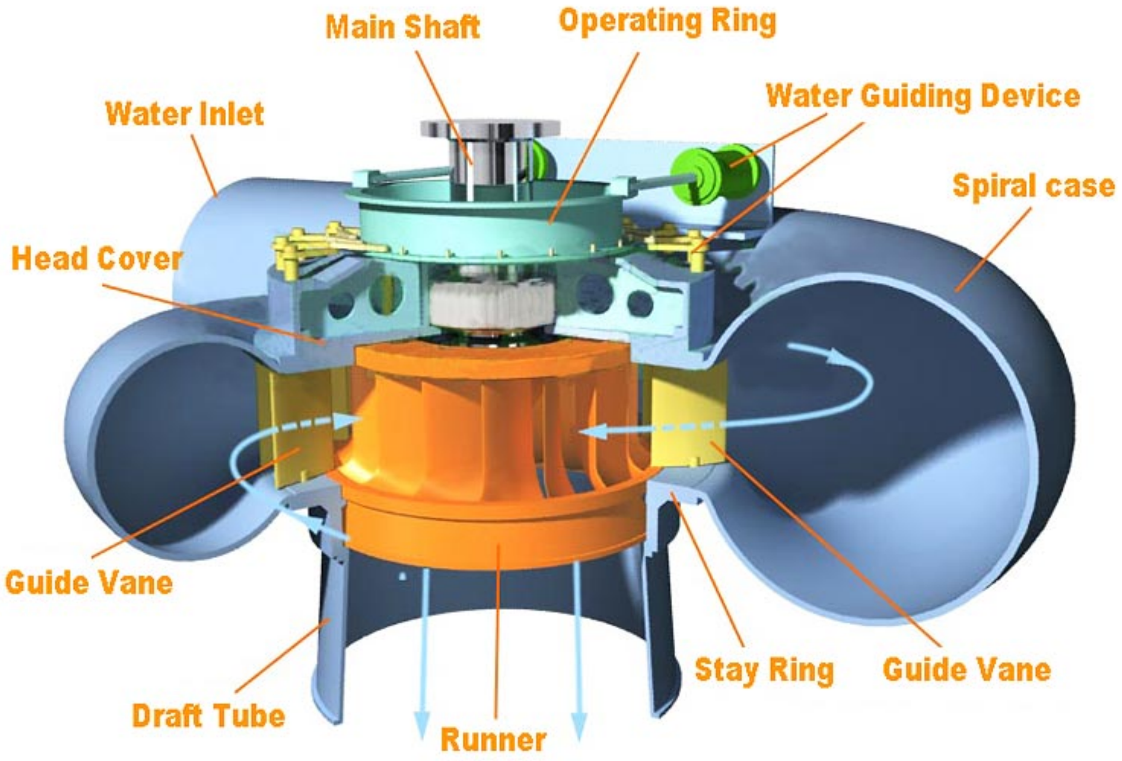

Figure 6: Components of a Francis Turbine (Mishra, 2018)

The Kaplan turbine, operates in a similar manner to that of the Francis turbine, where water enters via a draft tube and is guided into the runner blades of the turbine through stay and guide vanes. The clear difference between the two turbines, besides the application, is the runner blades which in the Kaplans case are attached to a turbine hub, similar in shape to that of a propeller turbine. The difference between, the Kaplan turbine and a propeller turbine although, its ability adjust the water flow into the turbine via guide vanes and most noticeably its ability to adjust the blade pitch to allow for the highest efficiency and varying flow rates. Semi-Kaplan turbines are those that have solely adjustable blades or adjustable guide vanes and not both. The hub is required for the Kaplan turbine, to not only hold the blades and the blade pitch mechanism but also to reduce losses through the prevention of vortex's that can occur. Governors not only control the guide vane mechanism but in the case of the Kaplan turbine control the pitch of the Kaplan blade, either mechanically or electrically.

In order for the HPP to create electricity, the turbines must be connected to a generator. Generators consist of two major components, the stator and the rotor, where the magnetizing of the rotating rotor through rotor poles, achieved from the torque developed from the turbine, induces a voltage in the stator. Stators consist of two main components, the winding and the core. The windings, or coils, is the point where mechanical work converts into electrical energy and consists of copper conductors that are electrically insulated to withstand the voltage being created. The stator core is the component that supports the windings in place, where the windings are normally arranged in slots around the core.

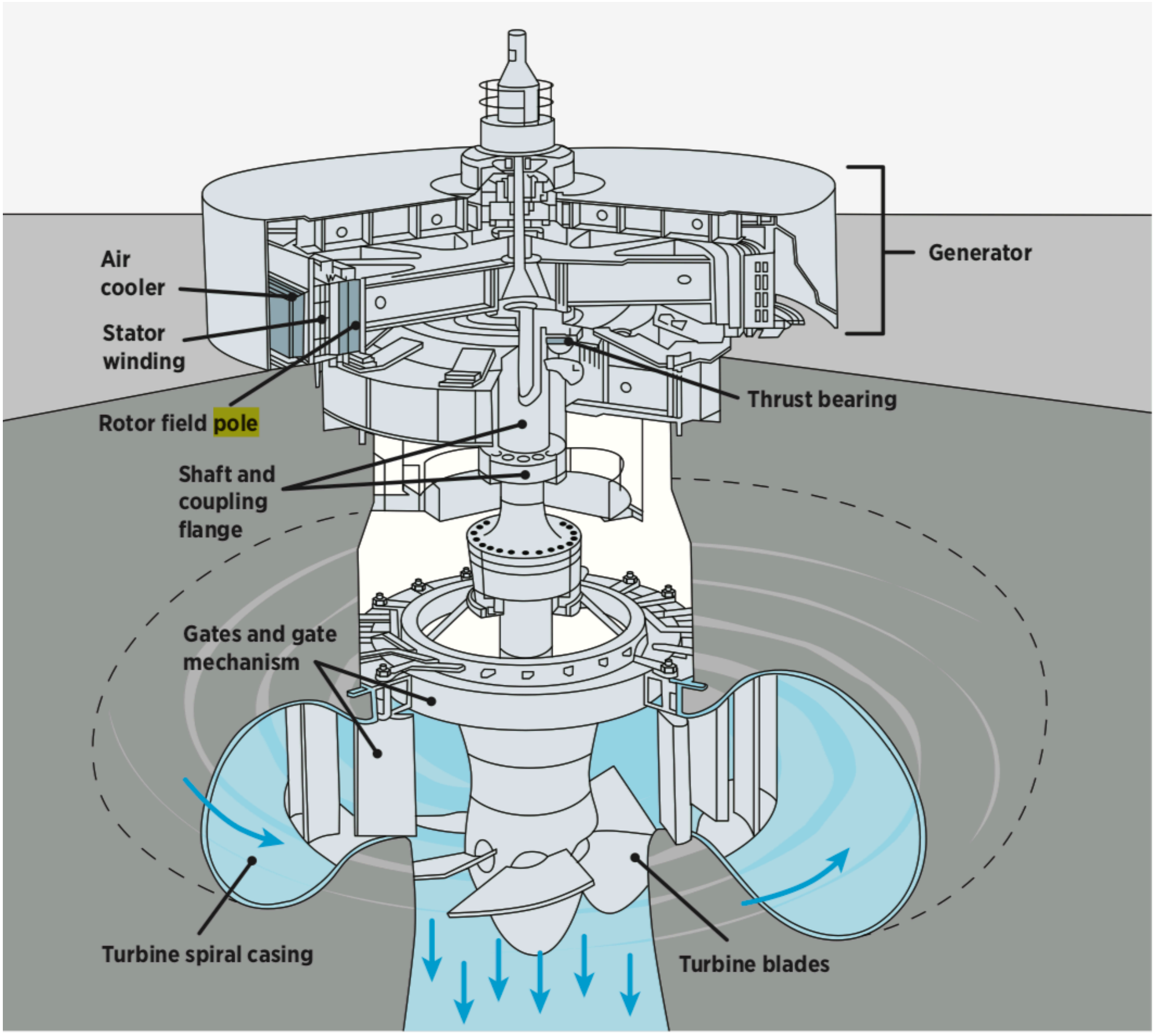

Figure 7: HPP Generator Components (US Department of Energy, 2016)

The generator rotor is connected to the generator shaft which transmits the torque generated from the turbine to the rotor, enabling it to convert the mechanical work to electrical energy. This is achieved through field poles that are connected to the rotor; like the stator, the field poles consist of insulated copper windings and are connected in series. To excite the field poles and produce a flux, an excitation system supplies DC current with the goal to prompt and sustain a voltage in the stator. Enabling the voltage generated to transport efficiently along the grid, a transformer is required to increase the voltage to 275 – 400kV.

Figure 8: Typical Field Pole (Mesa Associates Inc. and Oak Ridge National Laboratory, 2011a)

Generating voltage creates a large amount of heat, and in order to keep the machine running at optimum, a cooling ventilation system must be in place to cool the stator insulation material (Mesa Associates Inc. and Oak Ridge National Laboratory, 2011a). A generator ventilation system cools the components by passing air over the components by the use of a fan. On the GHES the cooling system comprises of finned brass tubes, that are water cooled air and arranged in parallel, where the cooling air is enclosed.

To give support to the generator a thrust bearing is installed either above or below the rotor, with either a guide bearing on either side. Most commonly in HP, these bearings are of the tiled-pad bearing type and consist of individual pads (shoes) that are tilted, adjusting to changes in operating conditions, and have the capability to handle large loads. A thin layer of lubricant, normally oil, is passed over the pad to prevent contact between the pad and the runner. The oil is fed from the lubrication system which cleans and regulates the temperature and pressure of the oil. Normally the pads are coated with a soft alloy called Babbitt, that prevents damage to the shaft and the bearing when there is a momentary drop in oil pressure. Guide bearings provide additional load support both axially and radially and are normally installed to increase the reliability of the machine.

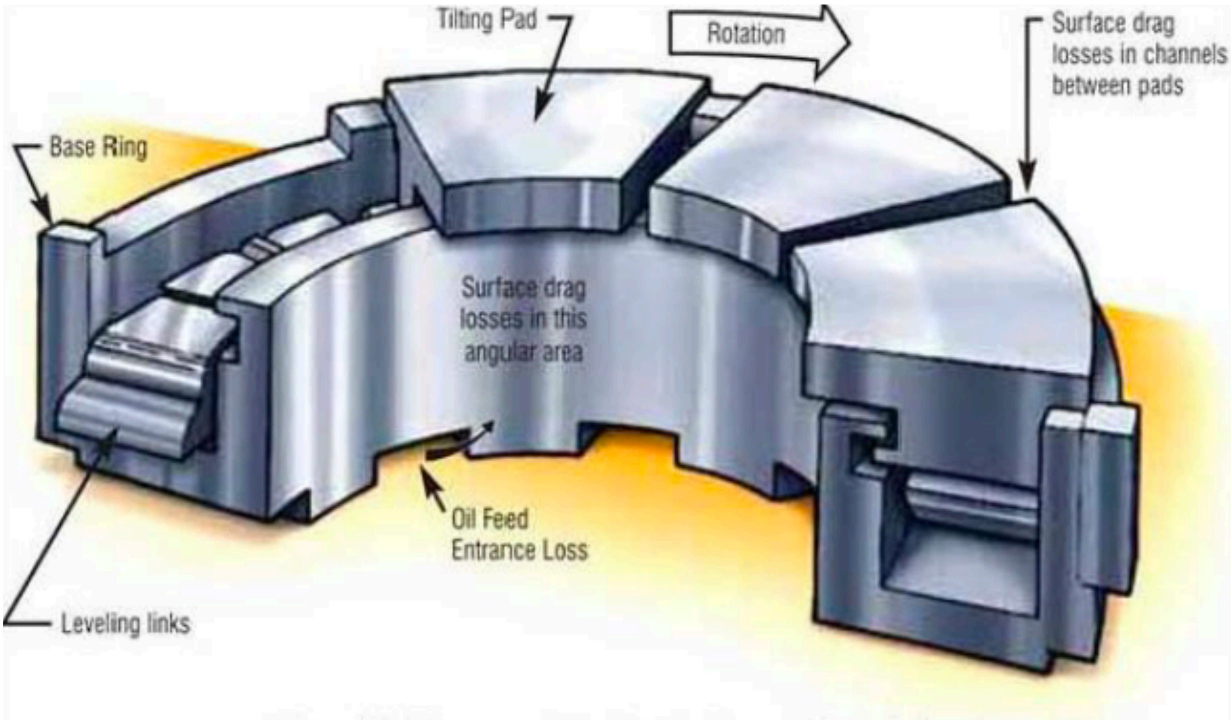

Figure 9: Components of a Tilted Thrust Bearing

In order to control and monitor the GHES, a SCADA (Supervisory Control and Data Acquisition) system is implemented throughout the scheme. SCADA is used as a means of communicating protocols and as a method of collecting data through a remote terminal unit, RTU, or a programmable logic controller, PLC. SCADA allows an understanding of any damage to selected equipment components, enables forecasting, and can implement an operating schedule. At GHES the SCADA system feeds back to the Glenlee power station, where operations and maintenance is achieved.

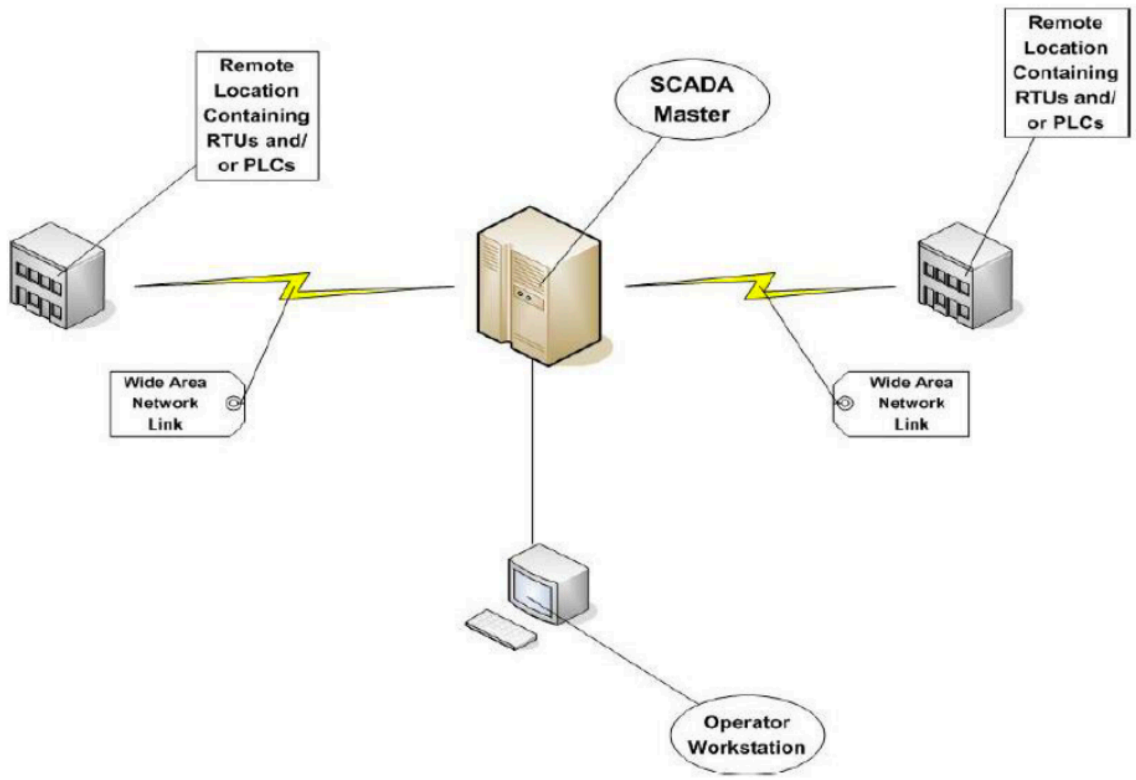

Figure 10: SCADA System Operation (Valentine, 2009)

HPPs Drumjohn, Carsfad and Earlstoun are subject to the renewable obligation certificate (ROC) subsidy. The Renewable obligation compels electricity suppliers to demonstrate that a percentage of their supply has been generated from renewable sources, and increases year by year, up to 10%. In return payments at per MWh are given to electricity supplier as a means of an incentive.

For Hydro to qualify for the payment it must meet one of the criteria below.

- Classified as Micro-hydro
- Commissioned after 1 April 2002
- Commissioned before 1 January 1990 but has undergone a renewal of major components and operates less than 10MW.

Micro-hydro is defined as an HPP with a net capacity of less than or equal to 1.25MW.

2.3 - Motivations for Retrofit

From a utility company point of view retrofit for increased efficiency/output, or ‘uprating’, enables the asset to stay reliable and improves availability, allowing it to continue to be a key asset for the network. Moreover, uprating improves the scheme’s flexibility allowing it to fit into the evolving roles required from it, as the level penetration of renewables increases – such as acting as a synchronous inertia or a method of grid control.

From a financial point of view, the introduction of new technologies into the plant through retrofit allows maintenance costs to be reduced, and efficiencies to be improved – ultimately increasing outputs. It is the most cost-effective, fastest and socially acceptable way for a hydropower owner to maximise financial output while enabling it to adapt to change in market dynamics. Moreover, as seen from the renewable obligation certificate subsidy, financial gains can be found through refurbishing of the plant. Refurbishment and uprating through retrofit will also improve the active life of the carbon-free asset, enabling the plant to stay a key part of the network for future generations.

The cost of a retrofit is a fraction of a new plant installation, and there are much less risks and environmental barriers associated. Moreover, retrofit also helps maintain utility companies’ sustainable image, without damaging it through the construction of an environmental impactful hydro plant.

Section III - Literature Review

The aim of this chapter is to review, and detail previous retrofit solutions installed into HPPs, that have either increased the efficiency or the output of the plant, by means of a literature review. This allows an opportunity to deepen understanding of the vast range of potential retrofit solutions, from the routine to the state of the art, that will supply solid support in the suggestion of potential upgrade solutions for the GHES. Moreover, the literature review should also act as a basis for any other HPPs that are considering uprating. The literature review will be structured in terms of the major areas where retrofit potential lies, to which further detail into the individual aspects of the components that have shown could aid efficiency or output improvement will be specified. A section will be left to discuss the various uprating approaches, to recognise methods of best practice when considering uprating. Where possible across the literature review case studies will be used to back up the theory found in literature, as well as references to the GHES.

3.1 - Refurbishment and uprating of hydropower

As the world transitions towards more sustainable and environmentally friendly energy sources, the refurbishment and uprating of hydro are essential in order to meet the growing trend of stochastic renewables entering into the market. Major renovations are already taking place in India and the US, with the US already have added an extra 2 GW to their HPP's through uprating by 2010 (US Department of Energy, 2015). While India is undergoing major refurbishment and uprating of its existing plants in the nation, as its government puts pressure on the power utilities to squeeze out as much energy, at as low a cost as possible (Rahi and Chandel, 2015).

In Scotland, due to refurbishment being key in order to receive the ROC subsidy, a number of HPPs have actually been de-rated through refurbishment since the early 2000's in order to fall below the 10MW limit set by subsidy, allowing utilities to maximise profits. Out with refurbishments intended for the subsidy, Lochaber has undergone modernisation in 2011 by the commissioning of 5 new turbine-generators, improving the overall efficiency of the station. Elsewhere, as part of SSE's £300 million program to refurbish their HPPs, Cassley Power Station have replaced their Francis turbines, while all the runners and guide vanes have been replaced in their Shin, Sutherland and Finlarig plants, all with the goal to improve efficiency of the plant (Power-eng.com, 2003) (GE, 2003). While more recently SSE has increased the output of their Lochay HPP near Stirling by 15% through uprating of its 1958 generators (Venables, 2016).

3.2 - Indicators & Approach to Uprating HPP

Discussed across literature, in the application of uprating hydropower, is the topic of indicators and approaches required when considering uprating an HPP. These two topics play an important role in the uprating process by describing the necessary steps required in order to identify potential solutions and to implement them. In respect to this project, these topics provided key information prior to the conducted site visit by giving a format to begin to seek for solutions. The following section will give further detail around these subjects.

Indicators

During a detailed literature review on the topic of HPP uprating indicators (Rahi and Chandel, 2015) revealed that when considering an uprating, indicators include the period of overflow, current efficiency and the time of license. This is similar to the indicators mentioned by (Blecken, 1997) in which the author states that uprating indicators lie in the plant's age, turbine and generator design, and limitations of the powertrain. Contrastingly, in the IEEE guide for rehabilitating hydropower plants, it is stated that indicators for uprating are in the failure of a major component, such as in the transformer, the turbine runner or in the generator (IEEE, 2006). In the thesis by (Sharma, 2006), the author took a more a detailed approach when seeking indicators, by developing a condition scoring systems out of 100, based on research, maintenance and evaluation of each sub-component. This is similar to the approach taken by (March and Wolff, 2004), although the author's approach for indicators relies more on data analysis.

Approach

Approaches to identifying potential uprating solutions vary across papers and companies, to which the following section will summarise those identified in the literature review.
(Goldberg and Lier, 2011) begin the approach outlined in their paper, by conducting a site visit to the power station to inspect the generating equipment, followed by a review of the turbine and generator condition, through current condition evaluation and maintenance records. This then leads to a deeper assessment of the machine condition, which then allows potential cost

estimates for the upgrade solutions to be devised. Efficiency curves then follow based on the potential uprating potential seen from the evaluation. Goldberg and Liers method conclude with an economic analysis to determine the cost benefit characteristics.

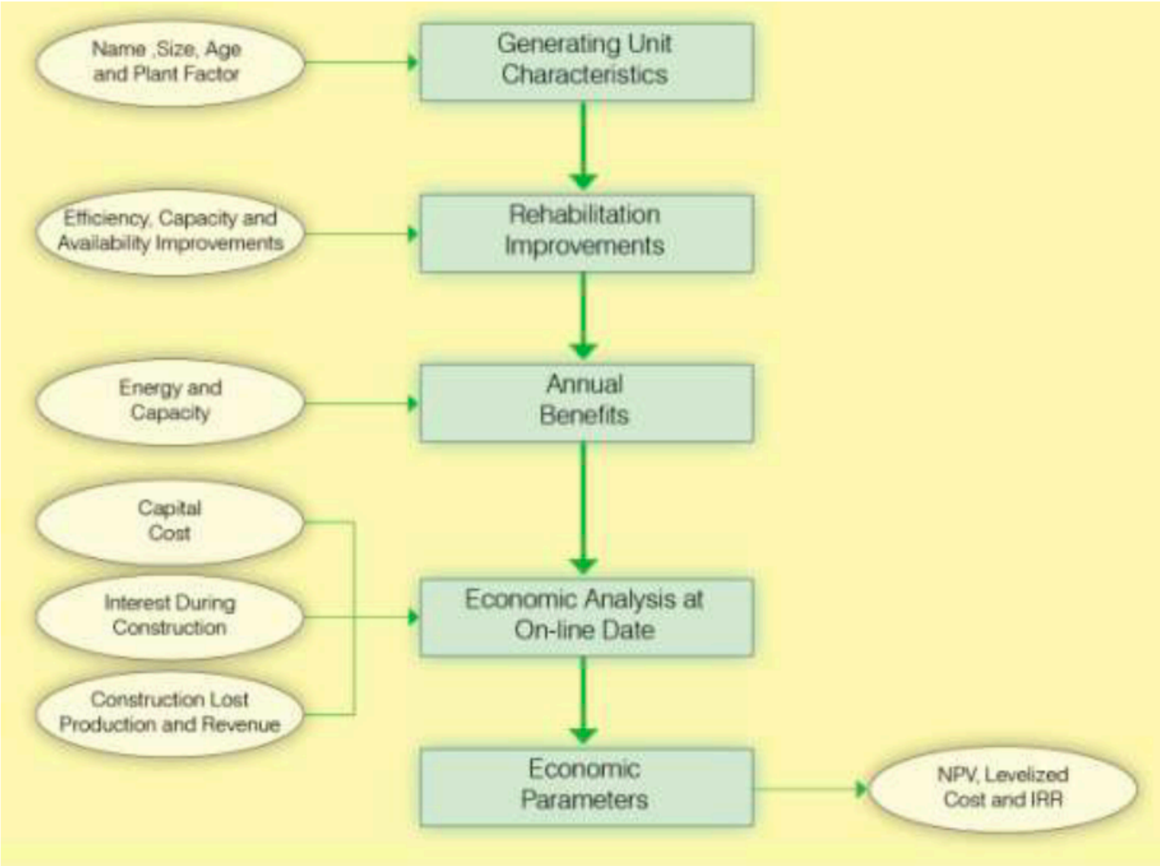

Figure 11: Flow Chart of HPP Rehabilitation Assessment (Gummer, 1993)

(Gummer, 1993), on the other hand, proposed a more detailed approach, where the author expresses that maximum information is required prior to starting the uprating; everything from the turbine to drainage. Andritz hydro, a world leader in HPP services, has developed a three-phase approach when considering modernisation. First diagnosis, consisting of assessing each individual component for risk and performance, in regard to its availability and level of maintenance, which is followed by analysis, which evaluates the uprating scenarios, and concludes with implementing the solution. BCK Mishra (2015) underlined a similar approach when evaluating the feasibility of improving the efficiency and/or output of the HPPs machines. This included, first assessing the current condition of each of the components of the machine by analysing the components history, the components performance, in reflection to its original performance and to the latest trends, and a diagnostic test to determine the remaining useful life of the machine. Once completed, the approach concludes by studying the components associated with the turbine and generator for potential uprating solutions.

3.3 - Uprating of the Turbine

The turbine, as a fundamental element in the power generation of the plant, lies within it an array of opportunities that could notably improve the efficiency, allowing greater output to be achieved. It is estimated in a 2010 study that in the US alone potentially 36 plants could increase their annual generation by 3% through a modern turbine replacement; based on the level of degradation of the plants (Bureau of Reclamation, 2010). When considering uprating of the turbine, it's current integrity, performance, hydrology, reliability, age, history, limitations, all have to be considered in contrast to its original performance and to current turbine technology (Sharma, 2006). The lifespan of a typical turbine is around 50 to 60 years, and with the majority of the Galloway Hydros installed in the mid-1930's, their lies potential scope for serious upgrading of the turbine. As the turbine type installed at the GHES consist of reaction style turbines, both Kaplan, vertical and horizontal, and Francis turbines, this literature review will focus in on those areas. The following section will break down the major components and areas of the turbine that if improved, could result in improved efficiency or output. Due to the similarities in components, upgrades will be mentioned for both Kaplan and Francis turbines, except when notable differences lie.

<u>Turbine Runners</u>

A significant and popular method for improving turbine efficiency, as well as its reliability and life, is the replacement and upgrading of the turbine runner. A number of issues can arise as the life of the runner increases, such as increased losses, mixing or frictional, or wear and tear through erosion, leading to the opportunity to replace the runners with new efficient designs and modern materials (Mesa Associates Inc. and Oak Ridge National Laboratory, 2011a). General Electric (GE) have stated that their new innovative runner designs can improve runner efficiency and therefore output by 5%, while it has been stated that in pre-1960s turbines it is possible to obtain increased output as high as 30% through efficiency increases of 1.5% by the modernising and replacement of runners (Bureau of Reclamation, 2010) (GE, 2018). In the modernising and upgrading of hydropower plants work that Andritz Hydro has undertaken, replacement of the runner has proven to be a key method in improving the output and efficiency of the plant, by appearing in the majority of their global hydro upgrade operations (Andritz Hydro, 2012). At a site in Akosombo Ghana, the supply of 6 new Francis turbine runners, as well as the adaptation of unspecified components, saw an increase in output of 25%, whereas at the Infiernillo Dam in Mexico, new runners and upgraded guide bearings increased the plant output by 28% (Andritz Hydro, 2012). As previously mentioned, projects across the US have been subject to uprating, where once more replacing of the runners is a common theme. At a site in North Carolina, established in 1919, all four of its Francis turbines were replaced in a refurbishment project that increased capacity by 45% (Ray and Martino, 2013).

Rated Head (meter)	Francis Turbine Age (Years)					
	60		40		20	
	Peak	Weighted	Peak	Weighted	Peak	Weighted
25-99	2.2	2.7	1.0	1.3	0.5	0.7
100 - 199	2.0	2.5	1.0	1.3	0.5	0.7
> 200	2.0	2.6	1.0	1.3	0.5	0.7

Figure 12: Francis Turbine Efficiency Uprating Potential (IEA Hydropower, 2000)

Increased efficiency of the runners can arise through modifying or replacing the blades with advanced blade profile and material and should be given high priority in the uprating approach (BCK Mishra, 2015). With that being said the following sections will highlight potential improvements that can be made in runner blade design and material.

Figure 13: Francis Turbine Uprating (Mesa Associates Inc. and Oak Ridge National Laboratory, 2011a)

Advanced Blade Profile

For over a century now efficiencies of large Francis turbines have been increasing steadily from 80% up to 95%, subject to design improvements in the runner blades (Gordon, 2001). New blade profile design includes the use of forward-leaning runner blades (FLB), where at the blade inlet on the band side of the turbine is modified to lean further forward, giving it a better flow of water over the blade, improving efficiency, while also reducing cavitation (Tani and Hanada, 2011). The FLB turbine was implemented into the Kansai HPP and resulted in output improvements of 4.7% (Tani and Hanada, 2011). In contrast where poor design of the turbines originally is revealed, lies potential scope for improving the efficiency by simply increasing the rotor diameter, as found by (Gordon, 2001).

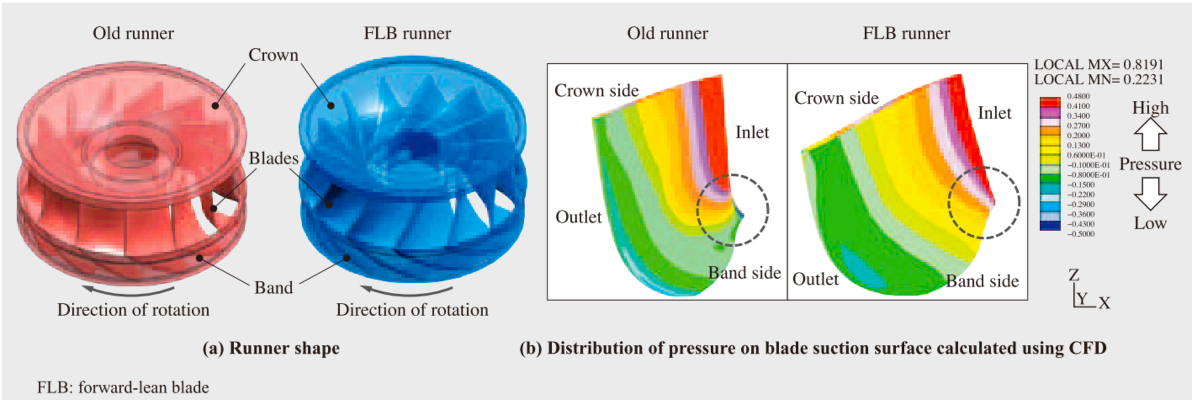

Figure 14: Forward Leaning Blade Francis Turbine Design (Tani and Hanada, 2011)

At the Akosombo HPP, in Ghana, modifications to the bottom ring profile and a reduction in the crown seal diameter eliminated the level of cavitation seen on the original design, as well as increased the efficiency by more than 2% at peak loads (Mielke *et al.*, 2005). Minor improvements can also improve the efficiency of the runner, for example, during the Shasta project the runner blade profile was modified for optimisation by increasing the blade thickness on the leading edge, allowing greater efficiency over greater turbine outputs (Bernard *et al.*, 2004). Across most runner blade profile design, it is the advancements in computational fluid dynamics (CFD) that have allowed the analysis of runner blades to be optimised for erosion reduction and efficiency improvements. As found by (Thapa *et al.*, 2012) who utilised the software to modify the blade profile by changing the angle distribution to by minimise damage due to sedimentation by 33% and improve the overall efficiency.

Material

Many of the runner blades on the GHES are fabricated from a steel casting or bronze in which lies an opportunity to replace the blades with more advanced materials, such as carbon or stainless steel (Mesa Associates Inc. and Oak Ridge National Laboratory, 2011a). New state of the art runners nowadays commonly uses ASTM A487/ A743 CA6NM Stainless steel due to their anti-cavitation capabilities and ease of repair (Mesa Associates Inc. and Oak Ridge National Laboratory, 2011a). Similarly, advances in manufacturing techniques can also aid the efficiency improvements seen from the instalment of new runners. (Thapa *et al.*, 2012).

Erosion

Combining both modern material and blade design can aid the prevention of erosion in the runner. Increasing erosion on the turbine directly influences the reduction in efficiency of the turbine, where the rate of erosion varies from site to site depending on the level of sedimentation, as well as the material properties of the sedimentation (Kumar *et al.*, 2011). Cavitation on the turbine parts, typically the guide vanes and runner, occurs normally on the suction side of the blade. Abrasion, on the other hand, occurs when the load in the turbine is subject to high sedimentation which can wear away the metal parts. The runner can also be subject to cracking arising from the cavitation, due to the onset of fluctuating loads, resulting in fatigue (Goldberg and Lier, 2011). Other areas of the turbine subject to erosion include galvanic corrosion, welding errors and damage caused through any debris that enters the system (Mesa Associates Inc. and Oak Ridge National Laboratory, 2011b).

During the refurbishment of the Orlik powerplant, it was found that due to excessive cavitation the efficiency of the Kaplan turbine decreased by 1.5% over the course of 4 years (Vitvar, 1989). One method of regaining efficiencies that have occurred due to the onset of erosion in the turbine could be simply replacing the turbine; although this is dependent on the cavitation rate and may not be cost effective. Though, developments in innovative design of the guide vane profile that produces uniform velocity, have shown to decrease erosion of the runners through the reduction of cavitation on the leading edge of the runner (Sanchez, 2012). Similarly, state of the art turbine design based on advanced materials could aim to prevent the onset of cavitation damage (Mesa Associates Inc. and Oak Ridge National Laboratory, 2011a). For example, in a 2018 study, (Kumar, Chittosiya and Shukla, 2018) investigated into the use of High-Velocity Oxy Flame (HVOF) based coating for turbine blades. HVOF coatings offer the reduction in cavitation through high resistance to abrasion, and its low porosity, where results have displayed a minimum 50% increase resistance - in comparison to the commonly used D-gun applied coating. Similar to advancements in runner blade profile design CFD can also play a role in reducing erosion on turbine blades, as found by (Thapa *et al.*, 2012), which using CFD analysis was able to modify the blade angle distribution of a Francis turbine runner blade to reduce erosion by 33%, with no loss in efficiency. During the site visit cavitation was found on some of the spare runners, as a result of pressure fluctuations where an overlay is used to repair the cavity.

Figure 15: Francis Turbine Cavitation Repair at Tongland

Seals and Wear plates

A study into increasing the capacity and efficiency of the Hoover Dam investigated upgrading the seal rings and wear plates of the turbine - normally overlooked components when considering uprating of the turbine (Sanchez, 2012). The wear plates were investigated in terms of reducing the corrosion arising due to water pressure, occurring on the plates; corrosion increases water leakage and therefore reduces the efficiency of the turbine runner. Erosion of the seal can also cause degradation of the clearance of the seal further increasing leakages as found by (Cook, 2008). A material redesign of the wear plates from chrome-vanadium steel to Nitronic 60 was chosen as the solution to the corrosion, due to its capability of wear resistance and oxidation resistance. Similarly, the seal rings of the turbine runner were also redesigned with Nitronic 60 and restored with tighter tolerances to improve the efficiency through reduced leakages. In the paper by (Sharma, 2006), the use of Nitronic 60 to improve cavitation resistance is also suggested along with the similar material Aluminium bronze. The combination of these machinery upgrades were calculated to give an improved efficiency of the plant by an average of 2%, and a capacity increase of 3%-5% (Sanchez, 2012). This is backed up by (Creager and Justin, 1950) where it is highlighted that leakages arising from the seal rings, can reduce the overall turbine efficiency by between 1%-3%, as well as by (Sharma, 2006), that confirmed a Runner seal replacement to either a crown or band seal can increase efficiency by up to 2%. Considerations, however, have to be made when considering a seal subject to the new pressure occurring once uprating has been undertaken (BCK Mishra, 2015).

Runner Seal Component	Modification and/or Replacement
Crown	0.2 to 2.0 %
Band	0.2 to 2.0 %

Figure 16: Efficiency Uprating after Rehabilitation (IEA Hydropower, 2000)

Guide Vanes & Stay Vanes

Modifications to the guide vane shape, have the opportunity to improve the overall operation efficiency by between 0.5 and 0.7%, as found from a study by the US Army Corps of Engineers (District, 2005). Modifications on the guide vane include an extension of the trailing edge, with the goal to reduce the gap that lies between the stay vane and guide vane, as well as a slight rotation of the guide vane (District, 2005). The results found by the US Army Corps of Engineers are similar to that found in the uprating of Akosombo hydroelectric plant, where modifications to the nose and trailing edge of the guide vanes, revealed efficiency improvements of between 0.1 and 0.2% (Mielke *et al.*, 2005). In other case studies, an EDF project to upgrade one of their hydro plants involved the changing of the hydraulic profile and the pitch circle diameter of the installed guide vanes to improve the efficiency of the plant by 3%, along with the instalment of a new runner. In this study, the position of the guide vane was also changed from an azimuthal position to an angular position. The guide vanes were modified to have a thinner hydraulic profile and closer tolerances, which allowed a 5.8% increase of flow rate to the turbine.

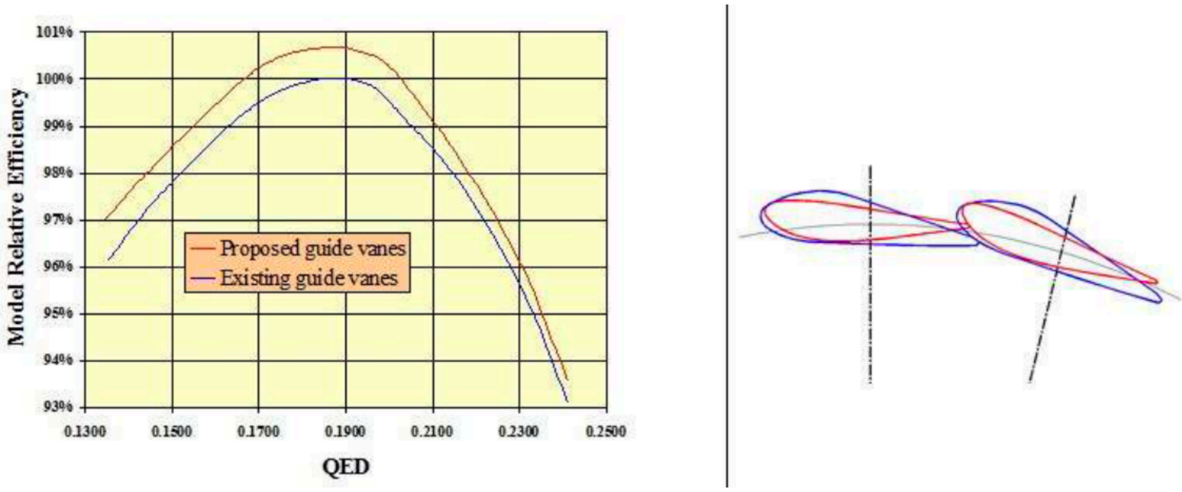

Figure 17: Modifying of the Guide Vane for Increase Efficiency (Bernard et al., 2004)

In the best practice catalogue for Francis turbines, it is recommended that for any turbines with a head over 30m, should investigate losses that occur through poorly designed guide vanes, as well as the effect of erosion on them (Mesa Associates Inc. and Oak Ridge National Laboratory, 2011a).

Figure 18: Spare Guide Vanes at Kendoon

Similarly, modifications to the profile of the stay vanes can also improve efficiencies. In the refurbishment and uprating of the Akosombo Hydroelectric plant, modifications of the profile found that at peak load, there is a 2.5% increase in efficiency, in comparison to the original shape. In older machines, manufacture procedures at the time produce a very crude guide vane profile, not optimised to reduce intrinsic losses. During the Chute-des-passes project, redesigning of the guide vane profile, with a good finish, improved efficiency of the turbine by 0.6% (Bernard *et al.*, 2004). At a similar site, the thickness of the guide vane and the length were reduced to improve an increased efficiency of 0.7%. Conclusively, changes to the stay vane, such as the lengthening of the profile or reducing the area the water takes, results in modifying the velocity pressure and the flow in the turbine, which using CFD for optimisation can have an impact on the efficiency of the turbine (Light, 2004).

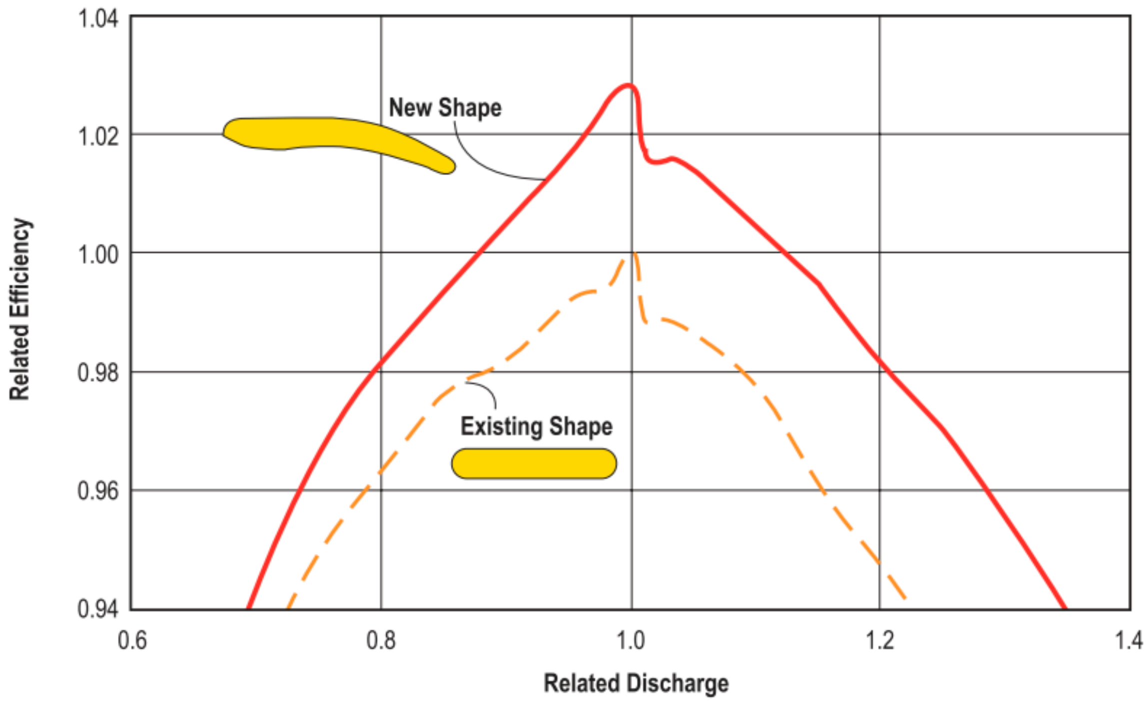

Figure 19: Stay Vane Modification for Increased Efficiency (Mielke et al., 2005)

The site visit did not reveal any previous modifications or modernisation to the guide or stay vanes on the GHES. The material used on the guide and stay vanes look similar to that used on the runner; either cast steel or bronze.

<u>Spiral Case</u>

The spiral case is rarely subject to refurbishment that will improve its efficiency unless however, cracks appear due to erosion arising from cavitation, abrasion, poor surface finish such as through poor welding modifications. Potential efficiency uprating can be achieved through either replacement or modifications to the casing such as through improving the surface finish. Improved surface finish reduces any distortion in the hydraulic design and in rare cases have been estimated to improve the efficiency by 0.3% (Sharma, 2006), (Mesa Associates Inc. and Oak Ridge National Laboratory, 2011b). In one case, contractors Alstom removed a pressure relief valve existing alongside the spiral case which reduces any overpressure and transient speed created form the penstock (Bernard *et al.*, 2004). Through the instalment of a new generator the possibility to reduce the transient speed, as well as adjustment of the guide vanes closing time, allowed the pressure relief valve to be disregarded (Bernard *et al.*, 2004). The spiral casings on the GHES are fabricated from stainless steel and are encased in concrete.

<u>Draft Tube</u>

In one example, during the refurbishment and uprating of the Akosombo HPP, considerations were taken to investigate the draft tube for potential efficiency improvements (Mielke *et al.*, 2005). Due to the poor rate of expansion, resulting from the design of the draft tube, a unique and innovative approach was taken to reduce the 1.5% drop in efficiency. The solution was to design and implement a horizontal splitter vane into the elbow of the draft tube, with the goal to improve the flow distribution and hydraulic performance, that would disregard the drop in efficiency through reduction in losses that occurred at higher flow rates (Mielke *et al.*, 2005).

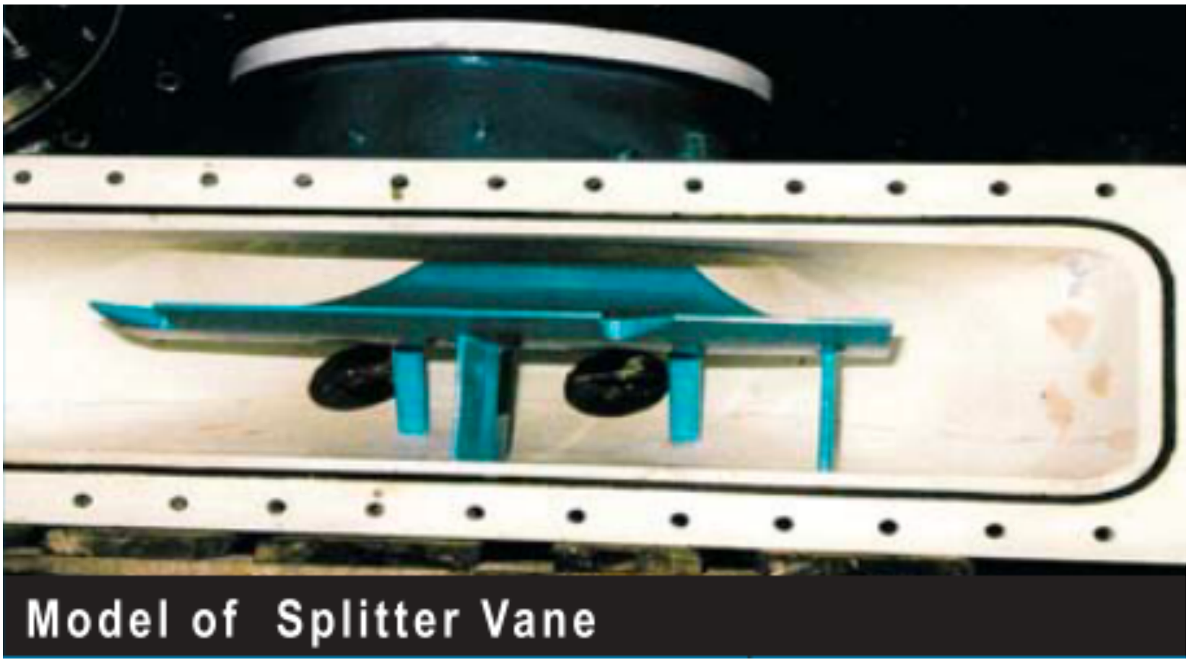

Figure 20: Draft Tube Splitter Vane Model for Akosombo HPP (Mielke et al., 2005)

3.4 - Uprating of the Generator

As the section of the power plant responsible for power generation, the generator should be seriously considered in the subject of uprating the generating capacity of the plant. According to Andritz Hydro, improvements of the generating components can increase output by up 25%; through the replacing of the stator and field poles. While hydro turbines are subject to large amounts of wear and tear through abrasion over its lifetime, the generator, on the other hand, requires attention paid to wear found in the slipring bushes. When considering uprating the generators, potential lies within the age and design of the generator (Blecken, 1997), where uprating usually occurs after the 30-year mark. Generators on the GHES consist of three turbo-alternators and haven't been replaced since commission in the 1930's leaving potential scope for uprating of the plant. In the following sections, components of the generators capable of improving the efficiency or output of the machine will be discussed. A good indicator for uprating the generator is the point at which the turbine capability exceeds that of the generator at the rated head (Bureau of Reclamation, 2010).

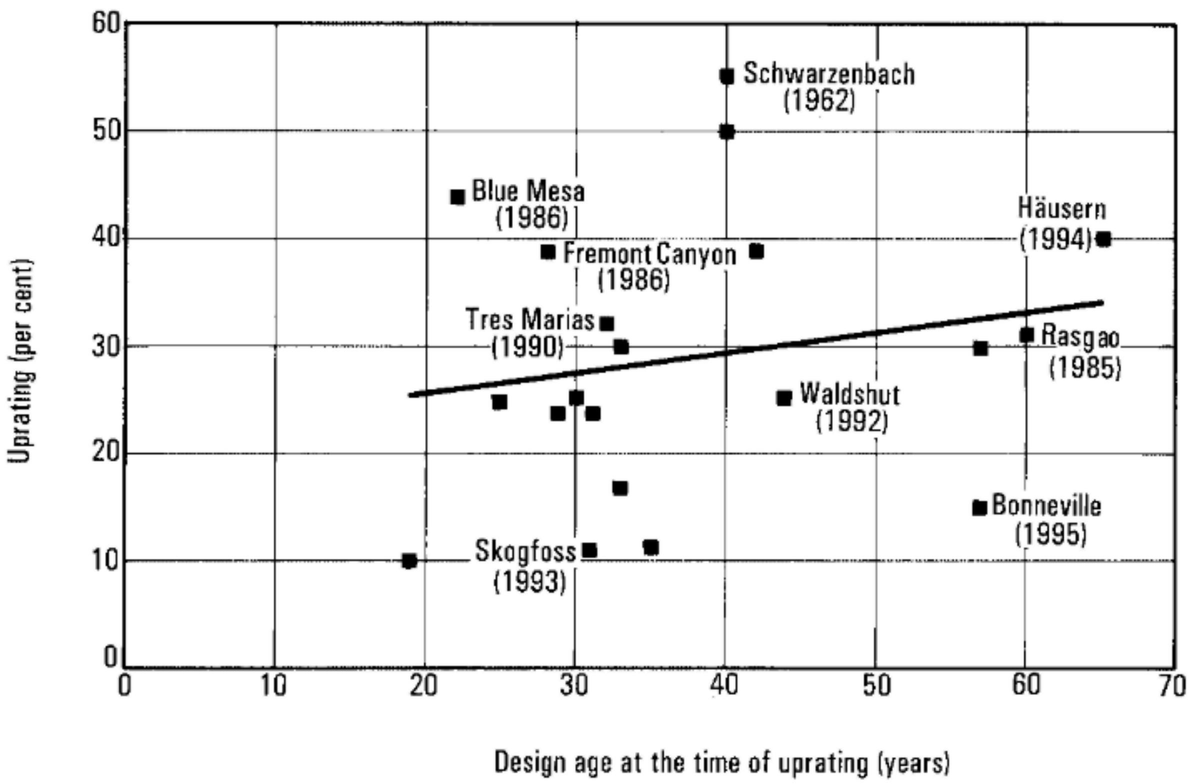

Figure 21: Siemens Case Studies of HPP Generator Uprating (Blecken, 1997)

Insulation

A popular method for increasing generator capacity in older machines is by swapping the class of insulation from B class to F class (BCK Mishra, 2015). Class F insulation with its capability to withstand higher temperatures and dielectric stresses, permits the use of thinner layers, increasing copper cross-sectional area, as well as reducing the resistance of the stator winding enabling an increase in output (Barbier, 2017) (Gorges, 2011). At the SSE owned Lochay Power Station replacement of the class B insulation to class F, increased the volume in each winding by approximately 5%, aiding an extra 15% output (Heel, 2014). On the GHES Class B insulation is currently installed in generators across the scheme. Considerations, however, must be made in regard to the reliability of the generator, when reducing the insulation thickness due to the onset of increased volts per millimetre of dielectric stress (Mesa Associates Inc. and Oak Ridge National Laboratory, 2011a).

Rewinding

Best practice for improving the efficiency or output of the generator, if the opportunity arises, is to refurbish the unit by rewinding of the generator. According to Andritz hydro stator winding replacements can increase potential output by approximately 5%-10% (Andritz Hydro, 2012). Stages of the rewind, normally include first stripping the original winding after data collecting, followed by the insertion of the new core and coils, and concludes with connecting the stator windings and reinsulating the motor (Gorges, 2011). During an upgrade at the Barron Gorge power station, a rewind enhanced the efficiency of the generator from 97.99% to 98.09% by reducing the losses in the generator, increasing output by 5 MW (Gorges, 2011). In the US from the periods of 1962 – 2005, 67 units have increased their capacity through rewinding of the generators with an average 15 % rated output. Rewinding should open up the opportunity to replace the insulation from class B to class F. Considerations, however, have to be made to the structural components, such as the stator core, frame, rotor, and the bushes, as the rewinding will arise with it additional torque and stress that could damage the components, through taking it past its yield point (Mesa Associates Inc. and Oak Ridge National Laboratory, 2011a). Similarly, considerations must be made to the potential mismatch between the transformer step up rating and the new generator output as a result of the rewinding (IEEE, 2006).

Figure 22: Routine Maintenance at a Generator at Kendoon

New Stator

In older systems, a new stator core may be advisory to improve output due to the state of deterioration that may occur, and therefore higher than usual losses. A new modern stator core composed of low loss materials have shown to reduce losses by 50% (Znidarich, 2013). As part of a stator redesign, at the previously mentioned Lochay Power Station, a new one-piece stator core was installed in place of the previous two-piece core, which along with new insulation material, revealed an increase in output by 15% (Barbier, 2017). Additionally, at the Barron Gorge Power station, a redesign of the stator coil enhanced the output of the generator output by 16.67% by slightly increasing the cross-sectional area of the conductor (Gorges, 2011). Similarly, as previously mentioned, replacing the stator core insulation from class B asphalt to class F epoxy, will allow the opportunity to implement more copper into the stator which can result in an increased generation (IEEE, 2006). Although if the opportunity lies, then an option to replace the stator core magnetic material with a new advanced material that has lower losses, will also further improve efficiencies and should be considered (Gorges, 2011). Considerations must be made in older machines, however, as the rotor field and stator may contain asbestos and should be contemplated prior to replacing the stator (IEEE, 2006)

New poles

According to Andritz hydro, changing the stator as well as the pole winding can increase the output of the generator by between 10-20% (Andritz Hydro, 2012). This can be achieved through the installing of new filed coils with a greater cross-section, as well as reducing the excitation requirements (Blecken, 1997). It is possible when installing new field coils to increase the width of the copper sections allowing the potential for more ventilation to be inserted – further reducing copper winding losses (Znidarich, 2013). Again, benefits can be further realised through the re-insulation from class B to class F. Improvements can be made to the field pole area by installing displacement fillets as well as installing rotating covers to improve the surface area (Blecken, 1997). Although, as clarified by (BCK Mishra, 2015), if uprating is below 20% then it is unlikely that there would be a need for the poles to be changed due to the long life associated to them.

Generator ventilation losses

Improving the ventilation can also play an integral role in the increasing of the generator power output (Moore, 2000). An improved ventilation system will allow a higher capacity of the generator to be run, where the heat created from the stator or rotor could be dissipated (BCK Mishra, 2015). This is taken further in the work by (Moore, 2000), where ventilation improvements were investigated in order for the generator capacity to increase by 30% but keeping the stator coil temperature at 70°C. In contrast, however, (Mesa Associates Inc. and Oak Ridge National Laboratory, 2011a) state that ventilation losses normally only consist of small improvements of less than 0.01%, where any major ventilation losses will come from a change in the copper. Although, (Goldberg and Lier, 2011), estimated a 0.3% ventilation improvements in medium to high generators, and can be achieved through analysis of the cooling air velocity at the outlet, flow distribution and heat transfer coefficients, without resulting in temperature rises of the active parts.

Generator bearings

Alternative methods for increasing the efficiency of the generator could look to the bearings for improvement. Babbitt is currently used on thrust bearings at GHES however frictional losses could be reduced through the use of technology using PTFE coated bearings pads in order to gain greater momentum (Znidarich, 2013) (Blecken, 1997). Similar to ventilation, heat can be dissipated better in the bearings, through the instalment of oil coolers and also the use of PTFE (Glavatskih and Fillon, 2006). In contrast (Mesa Associates Inc. and Oak Ridge National Laboratory, 2011a) have stated that in uprating, only very minor increases in efficiency can be achieved through the reduction in friction losses, and should be seen as a more reliability concern. If uprating does take place, then considerations have to be made subject to any additional loads on the bearings, as well as any rise in bearing temperatures, where monitoring is advised (BCK Mishra, 2015).

Governor

An uprating opportunity lies with the replacing of the governor with a new electrohydraulic governor, which can act faster-improving efficiency through optimising the rate of water to the turbine (Rahi and Chandel, 2015). In contrast, (Mesa Associates Inc. and Oak Ridge National Laboratory, 2011a)have stated that the model of the governor, does not matter as long as it is capable of providing accurate feedback loops. If a governor replacement is required, however, the oil pressure should be updated from 20 kg/cm^2 to 120 kg/cm^2 (BCK Mishra, 2015). Optimising of the governor though readjusted or recalibrated to ensure optimal performance (Mcstraw, 2000).

Excitation System

Uprating of the excitation system normally involves, replacement of all parts consisting should be considered (IEEE, 2006). Through the replacement of the exciter with a static excitation system can have the potential of improving the overall generator efficiency from 88% to 95%, through the retraction of the magnetic and mechanical losses associated with a rotating exciter (IEEE, 2006). In a paper by Rao et al, replacement of this original exciter with a new static exciter saw losses reduce by 30 kW (Rao KR, Mohanty BN, Rajaram PN, 1994). At an SSE site, retrofitted a new brushless exciter, however, this was to reduce the onset of dust and risk from outages (Bayar, 2017).

3.5 - Enhancements through Control Systems

The GHES already benefits from the automation of the scheme from a single plant, Glenlee, through the ability to control the output from afar through the use of the SCADA system. This reduces the need to manually increase the turbine speed to synchronous, saving time and money, while increasing reliability (Mckeown, Urquhart and Haining, 1987). Control of an HPP is normally a focus of availability of the plants on the scheme, through the ability to seek faults by means of condition monitoring and increase start-up time of a plant (McDonnell and Ward, 2018). The ability to condition monitor the system enables old power equipment on site to continue running at original performance, as seen on the GHES. The most noticeable way to increase the efficiency of HPP through control, however, is by operating the turbine in the most efficient manner, which in the case of the Kaplan turbine could be through adjusting of the blades, or optimising the speed based on the head present at the time.

<u>Variable Speed Turbines and Generators</u>

Implementing variable speed drives to generators can increase the system efficiency by adapting to the speed of the turbine, allowing optimal generating efficiency to be achieved resulting in an increase the output (US Department of Energy, 2016). Moreover, adjustable speed drives enable the possibility to broaden the range of efficient operation as well as an increased response rate (Ted K.A. Brekken, 2016). Most recently variable speed magnet generators normally used in wind turbines are being considered which could offer increase efficiency by adapting it to the hydropower sector (US Department of Energy, 2016)

In Kaplan and Francis turbines, variable turbine speed turbines can be applied to improve the efficiency of the plant by increasing the hydraulic magnitudes. In one example (Fraile-Ardanuy *et al.*, 2006) developed a variable speed turbine which adapts to the flow and head to produce the greatest efficiency at each moment, through the use of an automatic controller, the result was a yearly increase in output of 74.5MWh which increased output by 6.5%. Furthermore, (Heckelsmueller, 2015) applied variable speed technology to a Francis turbine where improved efficiency arose by the expanding of the range of efficient operation. Results highlighted efficiency increases of 22% at 40% below design head and 3% efficiency increase at 40% above the design head, through the controlling of the guide vane aperture.

Forecasting & Decision Support

Forecasting gives the opportunity to optimise the operation of the hydro plant. For example, (Madsen *et al.*, 2009), developed a method of improving hydropower efficiency through developing a system for simulating and forecasting in order to support a decision-based tool. The tool allows monitoring of the runners enabling adjustments for increased efficiency, as well as providing solutions to improve the operation of the power plant. The solutions are expected to increase production, by 0.2% through adapting the runners, 0.6-1.5% by turbine modifications and by 3% for the optimising of the operation of the plant. In the paper by (Cook, 2008) an example of a decision-based support system is described. The optimisation tool developed by Cook et al, considers the performance differences between plants and optimises plant output through data analysis and suggesting of operating settings. A decision-based support system could prove to be useful for cascading plants such as GHES. In a case study completed by the author of an HPP in Oklahoma, data gathering and analysis over a 3-month period resulted in the suggesting of operating settings capable of increasing plant efficiency by over 2%.

3.6 - Enhancements through Civil structures

While the majority of solutions for increasing the capacity of hydropower plants arise through enhancements of individual components, there still lies scope for increasing capacity through civil structures. The international renewable energy agency (IRENA) have specified that additional civil works to the plant, through renovation and upgrades, can result in an increase in capacity between 10%-30% (IRENA, 2012). In older hydropower plants, refurbishment of civil structures can prove to be economical, where structures such as penstocks and the water catchment area can have an economic lifetime of between 40 and 50 years (Goldberg and Lier, 2011). Improvements can include, increasing the head, reducing the sediment in the load, or the discharge capacity (Goldberg and Lier, 2011). Yet, as highlighted by (IRENA, 2012), the cost of uprating through the civil structures can be more than 5x more expensive than through enhancing through the mechanical and electrical components. In the following section, a summary of potential solutions found in literature will be discussed.

Penstocks

Penstocks can be improved through the use of advancements with new materials. Erosion and damage of the penstock as well as, organic or biological growth, such as mussels and clams, can restrict the water flow that reduces the hydraulic capacity. Modern solutions include the replacing of the penstocks with fibreglass material, where through the benefits in corrosive resistance and smooth interior can improve the flow capacity (Davis, 2009). Another solution could be to apply, or re-apply, coatings or linings to the penstock to prevent the build-up; liners such as silicone-bases fouling release systems. Moreover, investigations should be done to understand wither there can be any design improvements of the penstock, in terms of improving the head loss and reducing water hammer on the turbine.

<u>Limiting Erosion</u>

As previously mentioned in Section 3.3, erosion can have detrimental impacts on the turbines, leading to a decrease in efficiency as much as 3%. Changes to the land upstream of the plant either natural or artificial can increase siltation in the water, reducing the storage capacity of the reservoir (Lindström and Granit, 2012). One potential solution could be the use of de-silting chambers that removes the material from the water before entering the turbine (Kumar *et al.*, 2011). Other methods include simply the mechanical removal of the silt from the intake, and employing soil conservation techniques such as encouraging farmers to undergo preservation techniques for silt management (Mubanga, 2009). As recommended by (Petkovsek and Roca, 2014), if cavitation resulting from large amounts of silt is causing occurring problems on the turbines, then it may be beneficial to develop a numerical model based on data gathering to assess its impact on performance.

<u>Increasing Capacity</u>

Records at GHES have shown that since commissioning until 2010, rainfall at the site has increased by approximately 30% (Scottish, 2015). Thus, efforts may look towards increasing the capacity of the site, which would allow an increase in availability or to using the water released over the spillway to increase the output of the scheme. As stated in the introduction, the role of storage plays an important role in the energy transition towards a renewable and sustainable future. Added capacity would allow the GHES to play a bigger role in the renewable sector in Scotland by being able to further integrate with other renewables through providing of more power during periods of high demand and low load from other renewable sources.

Compensation recovery is a method of power recovery at reservoirs using water that would normally return to the river; normally conceived at micro-hydro scale. The energy recovered could be used to power the station or could be fed directly into the grid. There have been several case studies across Europe, where the use of compensation flow has been implemented into existing HPP (Esha, 2005). In a case study in Switzerland compensation flow from a dam in the Orge river, was used to produce just over half an MW more per year.

Integration of other renewables

To conclude this short summary on enhancing output through civil structures, there will be a quick look towards the area of integrating hydro plants with other renewables. The most vocal of these is the integration of existing HPPs with wind power, where a recent case in Germany, incorporation with GE, has proposed plans to integrate the two technologies. The innovative project uses wind turbines with integrated water reservoir to feed a HPP downstream, with the capability to produce close to 30MW (Grumet, 2016). Furthermore, an investigation into the possibility of a wind-hydropower plant in Greece proved to be an economical investment (Somaraki, 2003).

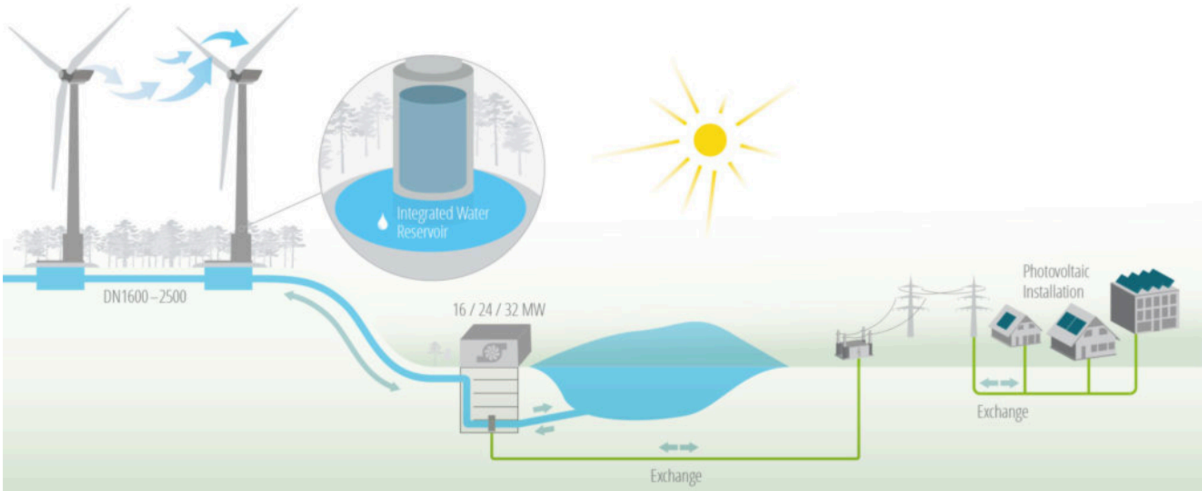

Figure 23: Integration of Renewables Example (Grumet, 2016)

3.7 - Conclusion

The literature review has revealed a number of ranging solutions proposed by authors and backed up through case studies. A common thread found through the literature review is the age variation of the papers and solutions discussed; a reflection of an established renewable source. Consequently, this proves to be key when determining potential solutions for an ageing power station such as GHES. Additionally, running themes include the removal and insertion of modern components and the use of software to provide optimal solutions that before were not possible.

Overall the solutions have been equipment based with the components incorporating the generator and the turbine being the most promising, due to the cost effectiveness of the solutions. With respect to the turbine itself, the most noticeable efficiency improvements lie with the runner, where modern design and materials can improve efficiency as much as 5%. Correspondingly, it was discovered that erosion plays a critical role in regard to the efficiency of the turbine runner, where efficiencies can drop as much as 3% - solutions around this were discussed. Preceding the runner, seals and stay vane enhancements could potentially increase efficiency up to 2%; although efficiencies this high is likely only for large HPPs. Minor efficiency improvements were found in respect to the draft tube, guide vanes and the spiral casing.

In terms of the generator, the most noticeable method of uprating was held around rewinding of the coils, both field and stator, where output improvements could improve as much as 15%. The insulation material alongside a new stator core revealed similar output improvements, with minor enhancements being found in the governor, bearings and in the ventilation. A summary of potential civil enhancements which could improve output were explored, as well as a glance into the role control systems have in regard to the output. Energy recovery through compensation flow was shown to hold potential for adding an additional output, while forecasting and decision support systems showed promise of improving plant output as much as 2%.

Not found in the literature review is output improvements or adjustments that would be required due to the onset of climate change. Moreover, pumped storage was not explored as a potential option, due to the operation of the plant not requiring the technology. The topic of the economics of hydropower was not explored, although a separate literature review will be conducted for the cost-benefit analysis of the proposed solutions.

Section IV - Potential Solutions

As mentioned in the objectives, as part of this project a site visit is to be conducted to GHES in order to determine the potential scope for the solutions found in the literature review. Following the site visit, there was scope for a number of the solutions, along with some others suggested by expertise on site, that are specific to GHES. However, due to the time constraints set on this project, only a select number of potential solutions can be taken forward for a technical and economic review - in which there will be a focus on the retrofit solutions which can supply the greatest increase in efficiency and/or output. Scope for potential solutions found during the site visit, that is not described in the following section, will be detailed in the future work.

Out of the solutions found, two stood out as major areas of potential improvement that could be taken further in detail within the constraints of this project. The first being a potential retrofit for a variable pitch Kaplan turbine at either the Earlstoun, Drumjohn or Carsfad HPP, which all have currently fixed blade Kaplan turbines installed. Variable pitch Kaplan turbines have been around for over a decade now, where obvious benefits lie with the technology, as mentioned in Section 2.2, in its capability to improve efficiency over a wider operating range due to its ability to adjust the blades in changing conditions. Curious to understand what kind of impact it could have on the plant, and if in the current climate it is even economically feasible, this led to further analysis of this proposition. The latter solution, being a result of the literature review, is an investigation into the potential efficiency improvements that could lie with a modern replacement or adaptation to the Francis turbines on site. It was found during the site visits, that little or no refurbishment or modernisation had been achieved with the Francis turbines on site since commissioning in the 1930s. As found in the literature review, within that time a number of technology advancements have been made in respect to hydraulic machines, which can enable a definite efficiency and output increase. Similarly, to the Kaplan turbine, the opportunity for efficiency improvements that could apply specifically to HPPs at GHES, as well as the economic feasibility of it, prompted its investigation.

In order to determine the true viability of these solutions, the following sections will consist of four main sections, based on the approach taken by (Goldberg and Lier, 2011). First, a technical analysis of the solution will investigate the performance benefits, followed by a discussion surrounding the practical feasibility. An economic feasibility will follow in the context of a cost-benefit analysis (CBA) and will conclude with a look towards the potential impacts and considerations that are required.

4.1 - Retrofit Potential of a Variable Pitch Kaplan Turbine

4.1.1 - Reasoning

The completion of Earlstoun and Drumjohn HPPs, occurred during the year of 1936, with Carsfad power station not being completed until the mid-1980's (Scottish Power, 2010). Each of these power stations is equipped with fixed blade Kaplan turbines with adjustable guide vanes or in other words semi-Kaplan turbines. Adjustable pitch Kaplan turbines first developed by Victor Kaplan in 1913, allow the possibility to the increase efficiency of the turbine through the use of adjustable blades (Dixon and Hall, 2010). The first instalment of such turbine was implemented in 1922 by a German engineering company Voith on a run of the river type power station, but it wasn't until 1924 in the instalment of an 8MW Kaplan turbine in Sweden that captured the attention of the hydro world (Singh, 2013). Since that time more information has been developed backing the efficiency improvements of full Kaplan turbines in comparison to other Kaplan type reaction turbines, as seen in Figure 24.

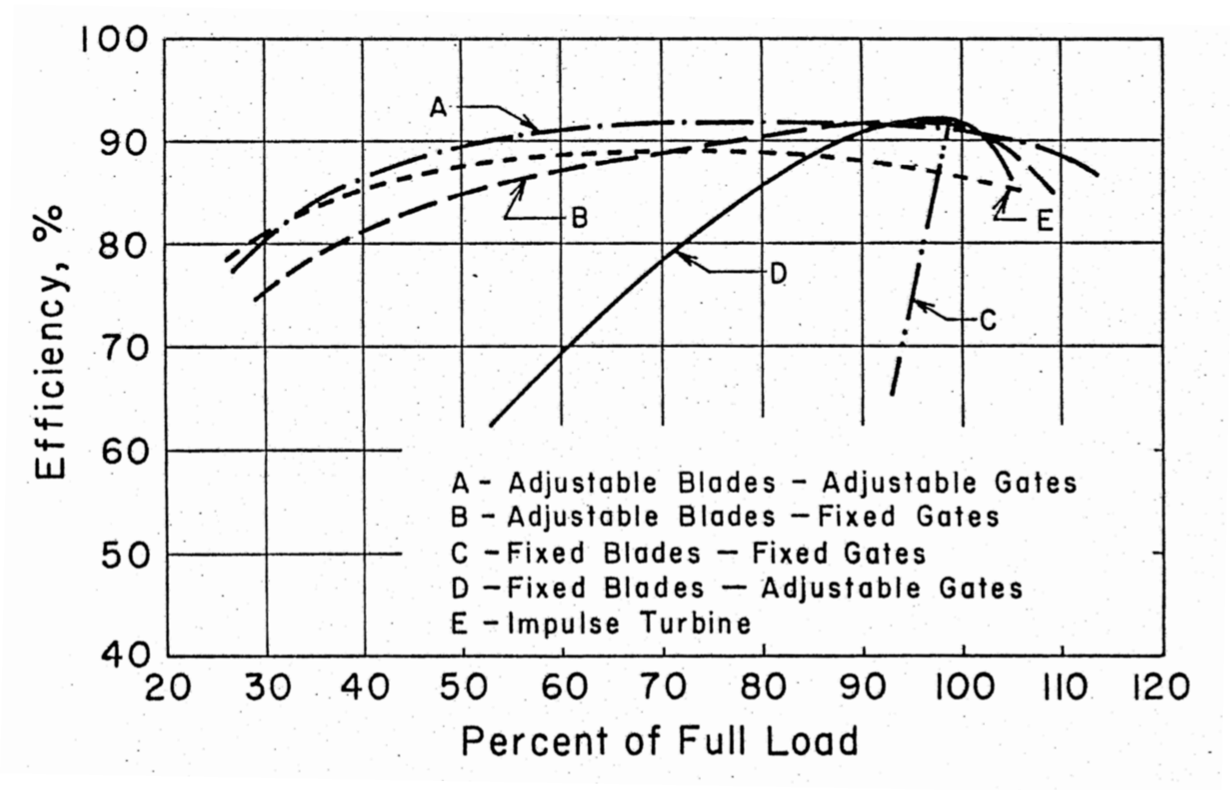

Figure 24: Efficiency Performance of Various Types of Kaplan Turbines (Farell and Gulliver, 1987)

Contrasting between the efficiency curves of Carsfad, Earlstoun and Drumjohn, (Figure 42 Appendix B) it is clear to see that those curves follow that of a fixed blade with adjustable gates, as seen in Figure 24 (Farell and Gulliver, 1987). It is also at this point that it is clear to see the potential efficiency improvements between an adjustable blade and fixed blade, as seen in comparison between curve D and A. The development of curve A through the constant adjusting of the blade pitch can be further clarified in Figure 25 which highlights the variation in performance between various fixed blade angles (Hutton, Eng and Member, 1954).

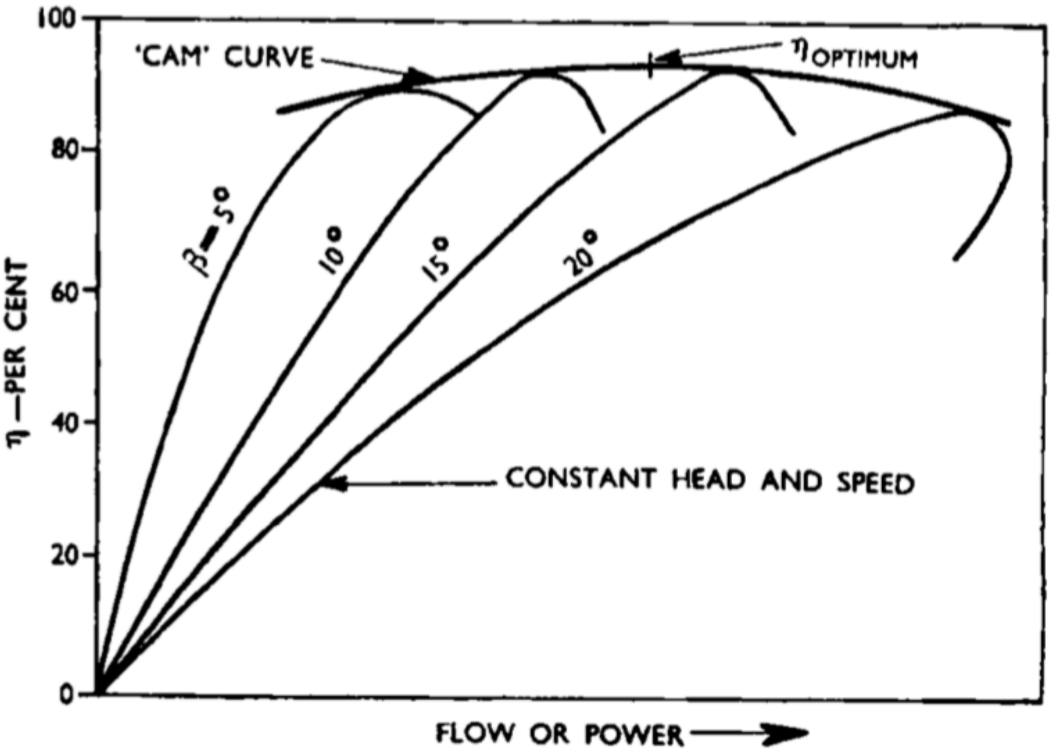

Figure 25: Performance of a Fixed Blade Kaplan Turbine at Various Pitches (Hutton, Eng and Member, 1954)

Evidence that a full Kaplan turbine would be suitable for this site, can be achieved through the determining of the specific speed of the potential turbine and comparing it against a design point curve. Taking the rotational speed of the turbine as 214rpm, or an angular velocity of 22.41rad/s, a head of 20m, and the typical power generated of 6MW, this allows the calculation of the specific speed, which calculates out to be 2.36 (Dixon and Hall, 2010).

Equation 1

$$\Omega_{sp} = \frac{\omega\sqrt{\frac{P}{\rho}}}{(gH_e)^{\left(\frac{5}{4}\right)}}$$

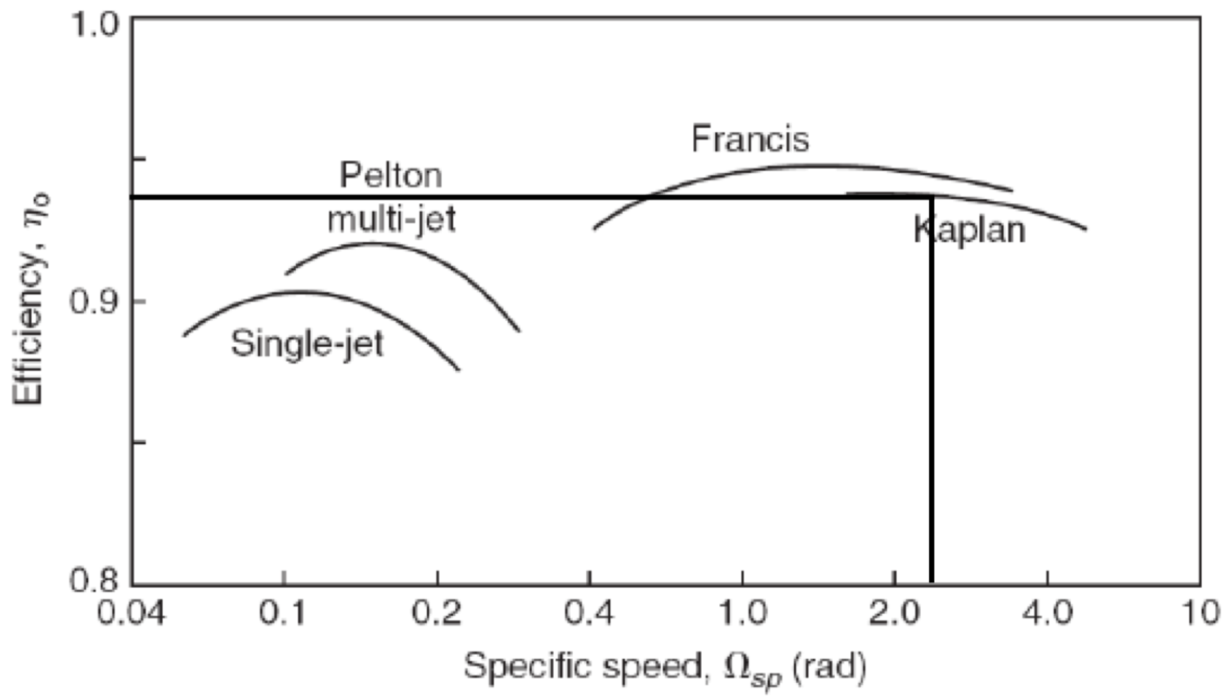

Figure 26: Specific Speed of Kaplan Turbine at Carsfad (Dixon and Hall, 2010)

Since it is already an established technology, the conducted literature review has not covered the potential efficiency improvements between Kaplan and Semi-Kaplan; except that discussed above. With that being said it is clear from the Figures 24 and 25 that potential efficiency improvements lie within flow rates away from the rated flow.

4.1.2 - Technical Analysis

To determine the increase in output and efficiency from the current installed semi-Kaplan turbine, to that of an adjustable pitched Kaplan turbine, a technical analysis is undertaken. Approach taken in the technical analysis is to model numerically, using hydraulic turbine design equations, the conditions of the currently installed semi-Kaplan turbine with adjustable guide vanes at rated flow. Since the guide vane angle and runner angle were unable to be obtained from site a method was required to calculate them. Using existing performance curves, 'goal seek' on Excel is used to determine the guide vane angle required to produce the output and efficiency at the rated flow (Appendix B, Scottish Power, 2010). Once completed, the modelled blade angle can be fixed through manipulation of the formulae, to which 'goal seek' can be used once more to calculate the guide vane angle at each change in flow rate, to calibrate to the expected efficiency shown in Appendix B. Through the equations in Appendix D this then allows the original power output against flow for the current installed semi-Kaplan turbine to be calculated.

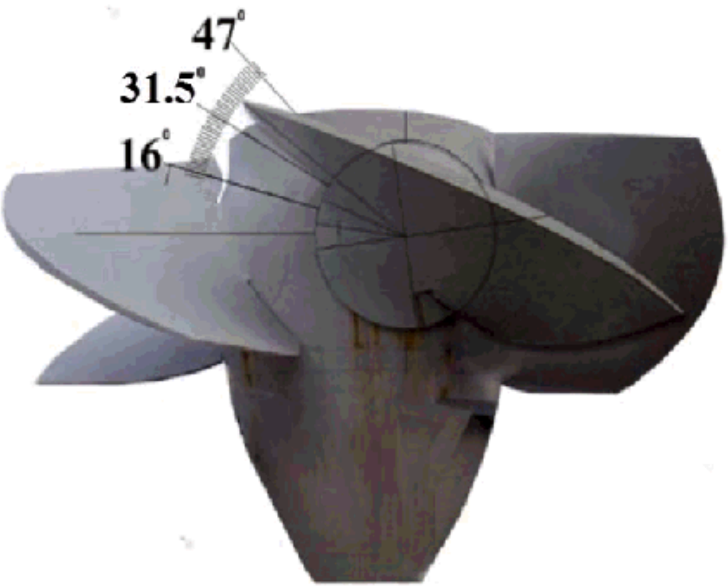

Figure 27: Kaplan Turbine Pitch (Actuation Equipment Test Co, 2016)

The retrieved efficiency curve, Figure 42, however, is limited to 60% of the rated flow, therefore the following analysis will only consider efficiency and power output improvements above the rated flow. This is due to the inaccuracies of calculating the turbine losses required when projecting the remaining curve. An attempt was made to calculate the remaining flow rates below 60% and the efficiency improvements that can be made through changing of the guide vane. However, inaccuracies in determining the losses in the turbine, revealed the results diverge away from that found in literature past 60%. Moreover, flow rates below 60%, in any case, are relatively insignificant as it is unlikely in a storage-based HPP, for the flow rates to fall to this level. Additionally, once the turbine reaches the flow that enables synchronous speed it is assumed that the turbine would want to achieve as close to rated flow as possible.

To calculate the efficiency improvements seen by adjusting of the blade angle, 'goal seek' was used once more to determine the blade angle required in order to meet the rated efficiency, at incremental changes in flow to that of the rated flow, Q/Q*. This method assumes that the level of calibration of the calculated losses to the existing curve are the same as that experienced during the manipulating of the blade pitch. As a result, a graph can then be depicted of varying blade angles and their efficiencies against changing flow rates, similar to Figure 25. To which using the method developed by (Hutton, Eng and Member, 1954), a "cam curve" can be estimated for the newly installed turbine. Results can be seen in Figure 29, while the calculated guide vane angles and blade angles against flow rate can be seen in Table 1. In doing this, the blade angle was rounded to the nearest whole number, due to the probabilities in real life scenarios of adjusting the blade to such calculated accuracies being small.

Table 1: Flow Rate vs Blade Angle

Q/Q*	1	0.95	0.9	0.85	0.8	0.75	0.7	0.65	0.6
Blade °	48	45	42	39	37	31	26	23.5	21
Guide Vane°	45	47	48	50	52	54	55	57	59

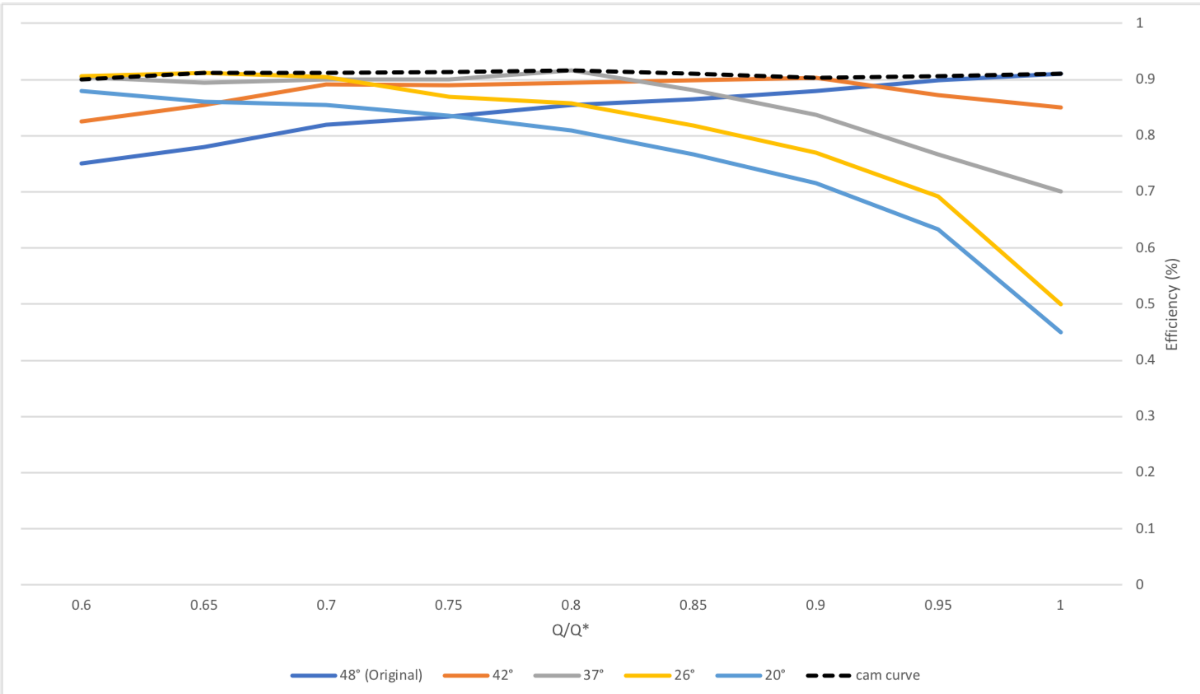

Figure 28: Calculated Performance Curve for a Full Kaplan Turbine at Carsfad

Differences between the two models of the turbine, fixed and with an adjustable pitch, can now be compared in reference to the efficiency vs flow rate and power output vs efficiency curves. Calculating the differences in power output between the two designs will then allow the performance benefits for the cost-benefit analysis to be realised.

4.1.3 - Feasibility

In order to understand whether it is possible to retrofit an installed semi-Kaplan turbine for an adjustable pitch Kaplan turbine, it first essential to know what components and operational systems are required for the adjustable pitch Kaplan and not the for that currently installed. To operate the variable pitch blades requires a blade servo which is operated by the governor (Olofsson, 2009). The role of the governor is to adjust the oil pressure either side of the blade in order to overcome the frictional and torque forces exerted onto the blade to achieve the required angle (Army Corps of Engineers and Administration, 2009). The oil reaches the blade through three oil pipes, from the oil head situated above the generator - where pressures can vary between 35 to 70 bar (Army Corps of Engineers and Administration, 2009). Two of the three oil pipes extend to pistons that power the movement of the blades on top and below of the blade, while the third applies a pressure to the hub of the turbine, in order to prevent leakages and supply a constant flow of oil in the bearing. The movement of the blade through the pressurising of oil and the piston is done through the blade servo motor and is connected to the crosshead. The crosshead is then attached to "eye ends" at each blade which is through the use of a linked pin connected to the link plates. Link plates connected to the blade lever are the final components of the adjusting mechanism, besides the blade itself. Typically, the blades can adjust between 16° and 37° - giving initial verification of the angles calculated. (Army Corps of Engineers and Administration, 2009).

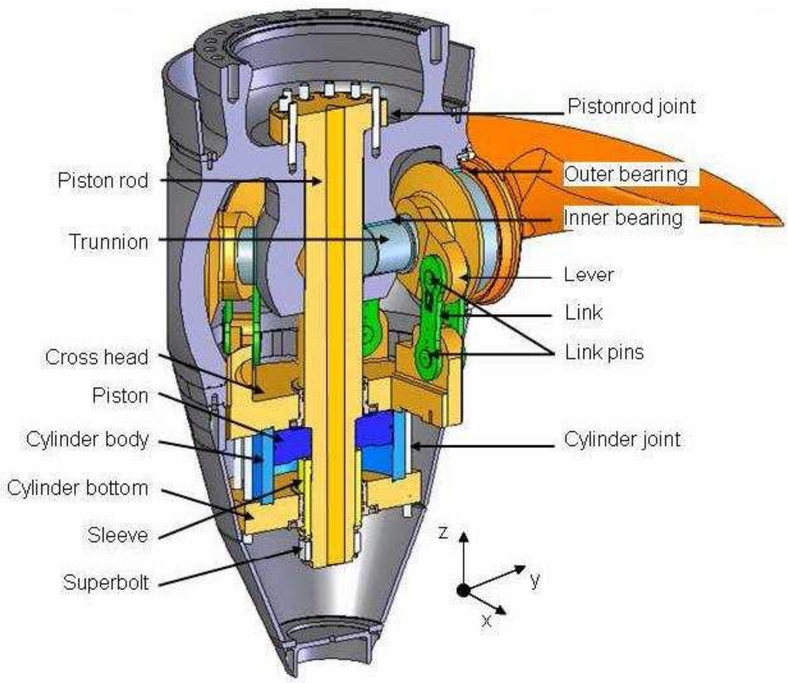

Figure 29: Kaplan Turbine Adjustable Pitch Components (Olofsson, 2009)

As a result, it is essential that in order to retrofit a propeller with a Kaplan turbine, then the following components are required. Out with the Kaplan hub, installation of a control system which would feed back to the SCADA system, allowing control and monitoring, would also be required. The data collecting would further allow optimal use of the Kaplan turbine, through data analysis. In order for all of this to happen the turbine must be "de-watered", removed and potentially dismantled. Post-installation should also follow a period of testing that would validate the retrofit.

In terms of retrofit potential for this solution, there lie two potential approaches found in literature, to either simply replace the turbine as is or to retrofit the components necessary into the existing hub of the semi-Kaplan unit. While the latter option may be more cost-effective in regard to component costs, the prior may be subject to a shorter project time and fewer maintenance costs. Moreover, while the prior is less common a paper on the conversion from Kaplan to propeller and full repair of a Kaplan turbine was found and used to understand the feasibility of such a task (Army Corps of Engineers and Administration, 2009). A critical factor, besides the cost-effectiveness of the solution, is the allowable space inside the semi-Kaplan to hold the discussed components.

4.1.4 - CBA

To support the proposed solution of possibility retrofitting a Kaplan turbine into either the Earlstoun, Drumjohn or Carsfad power stations a cost-benefit analysis, CBA, is essential. As previously mentioned there lie two approaches to retrofit potential of a Kaplan turbine; Both approaches will be analysed in the following section prior to a CBA. For the following analysis, Carsfad will be used as a case study, due to the level of information made available for the site.

Costs in this matter will include the cost of implementing the retrofit solution, the cost to operate and maintain the new turbine, and the revenue lost during installation. Implementation costs should include the following.

- Component (Inc. shipping)
- Labour
- Design & Engineering services
- Certification & testing
- Lost Revenue
- Contingency costs

For retrofit of the existing Kaplan, a literature review was conducted to find similar projects and their associative component costs for the blade mechanism. Resulting from the literature review part costs recorded during the previously mentioned refurbishment of a Kaplan hub, at unit 16 of John Day Dam, Portland District, USA was found (Army Corps of Engineers and Administration, 2009). Component costs for the blade mechanism specifically were recorded and stated to be $698,204, equating to £542,783, at the current exchange rate. Yet, this was discovered to be for a Kaplan turbine with an output of 135MW, compared to the 6MW found at Carsfad. To give an estimation of the difference in component costs between the two sites, the cost ratio of a new Kaplan turbine was estimated as a function of flow rate and head for the two units using the formula developed by Aggidis *et al.* (2010).

Equation 2

$$\mathrm{C_{Kaplan}} = 46{,}000 * (\mathrm{Q} * \mathrm{H})^{0.35}$$

$$\mathrm{C_{difference}} = \frac{46{,}000 * (538 * 31)^{0.35}}{46{,}000 * (37 * 20)^{0.35}} = 1.975$$

This results in a cost ratio of 1.975, which to the nearest thousands produces a component cost of £275,000. Moreover, costings were taken during 2009, to which considering inflation results in a final estimated component cost of approximately £350,000 (Bank of England, 2017). Employee hours recorded for the turbine repair at the site were also available, and therefore are utilised for labour costs to give further clarity to the project. Estimates not taking from the labour recorded hours, are the installing of the blade mechanism, where an initial two thousand hours was initially predicted – if necessary a sensitivity analysis will follow. An equivalent employee rate recorded by (Army Corps of Engineers and Administration, 2009) of £100 per hour is used for the investigation; inflation and exchange rates considered. If an assumption of five employees working on the project, five days a week is to be made, this would equate to a project time of 95.5 days. It is also assumed since the blade mechanism is installed inside the propeller unit, there will be no change in civil structures.

Table 2: Estimated Labour Time for Blade Components Installation

Procedure	**Employee Hours**
Dewater the unit	100
Turbine removal	400
Install Blade mechanism	2000
Re-commission	200
Total Hours	2700
Total Cost	£270,000

Design and engineering service costs are taken as 17% of the total component cost based on that estimated by (NLine Energy, 2016), and certification cost are taken as £25,000 from similar estimates in an internal report (Mott MacDonald, 2004). Lost revenue is taken as a multiple of the project time, based on the estimated labour time, and the average daily output of 32.2 MW. A strike rate of 9.43 p/kW was used for the purposes of this project (OFGEM, 2018)(renewablesfirst.co.uk, 2016). This is based on the sum of the export price at 5p/kWh, assuming 100% of the energy generated is exported to the grid, and the latest feed-in tariff rate for hydro at 4.43 p/kWh. The ROC subsidy which is obtained from Carsfad is not considered in the analysis, due to the output not exceeding the 10MW limit. Contingency costs are taken as 25% of the total installation costs, however, a sensitivity analysis on this estimate will follow.

Table 3: Kaplan Turbine Retrofit Costs

Item	**Costs (£)**
Component	350,000
Labour	270,000
Certification & Testing	25,000
Design & Engineering Services	110,000
Contingency Costs	260,000
Lost Revenue	287,000
Total	£1,300,000

It is expected that there will be an increase in operational and maintenance costs, arising from the controlling and monitoring of the full Kaplan turbine. Estimates are taken as the difference between the estimated cost of a Kaplan turbine and the estimated cost of a semi-Kaplan turbine

(Ogayar and Vidal, 2009). Ogayar and Vidals method is used in this instance as it allows a comparison between the two models; it was not used previously in the component estimation due to the papers focus on Kaplan turbines with heads smaller than 10m. For the calculations, head is taken as 20m and power as 6MW (William, Eng and E, 1938).

Equation 3

$$\text{Semi} - \text{Kaplan Cost} = 19.498\text{P}^{-0.58338}\text{H}^{-0.113901} \quad (€/\text{kW}).$$

Equation 4

$$\text{Kaplan Cost} = 33.236\text{P}^{-0.58338}\text{H}^{-0.113901} \qquad (€/\text{kW}).$$

$$\text{Cost Difference} = 0.00262 - 0.00154 = \ 0.00107$$

With Carsfad estimated to produce 11750 MW/year per turbine, this equates to £14,500 per year in operational costs, which after inflation and exchange rate, equals approximately 1.3% of the installation cost (Scottish Power, 2018b). Consequently, for the CBA the operational rate will go up as the output difference from the retrofitted Kaplan turbine varies.

As previously mentioned, instead of retrofitting the existing semi-Kaplan unit, the opportunity could lie to simply replace the turbine altogether. Using once more Equation 2 reveals that the expected Kaplan cost would be £592,340, after inflation. Differences in cost between the renewal of the hub and simply replacing the unit will also see a reduction in project time, arising from the time spent implementing the solution. However, the new Kaplan turbine would still need to connect to the governor, which from the case study was expected to take 400 hours (Army Corps of Engineers and Administration, 2009). Assuming the remaining labour time will stay consistent, this results in a labour cost of £110,000. The remainder and subsequent costs associated for the unit are expressed in Table 4.

While component costs are higher, the subsequent drop in the time results in a total cost of £100,000 lower than the retrofit solution, less than 10% different. There will also be an expected maintenance reduction cost from implementing a modern turbine, which from literature has been estimated at 2.5% of the project cost (IRENA, 2012). Subsequently, due to the lack of literature backing the labour costs for the retrofit option, even with half of the labour cost both cost estimates will appear around the same price. Although the reduction in maintenance cost for the full turbine replacement is a key factor in the overall cost of the retrofit option, therefore the following analysis will use this method of retrofit for the cost.

Table 4: Replacing of the Turbine Cost

Item	**Costs (£)**
Component	592,000
Labour	110,000
Certification & Testing	25,000
Design & Engineering Services	124,000
Contingency Costs	242,000
Lost Revenue	117,000
Total	£1,210,000

Discount Factor is taken as the combination of the Scottish Power discount rate of 7.5% and an inflation rate of 2.5%, equating to a i_r= 10%, where *n* is the year number since the start of the project (Rahi and Kumar, 2016) (Scottish Power, 2018b).

Equation 5

$$Discount\ factor = 1/(1 + i_r)^n$$

Since the adjustable pitch design does not increase the power output at the rated flow, as it is assumed the semi-Kaplan turbine is designed for optimum efficiency during that point, the performance benefits rely on the variation from the rated flow at the site. Other benefits will include possible life extension and reduction in cavitation that can be achieved. However, these aspects will not be explored in the following analysis, due to the historical records of cavitation not known and the condition of the turbine already being well maintained past its life expectancy.

As the average daily running hours and the flow rate of the site are hard to quantify due to it being dependant on rainfall/ reservoir levels, these parameters were unable to be obtained. It is known, however, that there is an yearly average production at the power station of 11751 MWh/year, per turbine, which would equate to running at an average of 5.37 hours per day at full load (Scottish Power, 2018b). While the definite average daily operational time, ADOT, of the plant is not known, a sensitivity analysis can be used to determine at changing average operational times, the minimum time required not spent at rated flow in order to make the project economically beneficial.

This can be achieved through the aid of solver on Excel, where an objective can be set, i.e. set the sum of the total output in the day equal to the average daily output, 32.2MW, and constraints can be established. Constraints in this instance include ensuring the sum of the running hours is equal to that estimated in the sensitivity analysis and ensuring the plant runs at full load for the maximum amount of time possible. The preceding constraint assumes that it is preferred that the turbine operates at rated flow for as long as possible in a day and helps calculate the minimum variance in flow from the rated required. This constraint also prevents solver reducing the rated flow to zero in order to make a profit from the newly installed turbine. Since the accurate efficiency curves granted only detail up to 60% flow capacity, the analysis will be undertaken in this range. Using the calculated power outputs from the original efficiency curves, assuming that when the turbine is at rated flow power output equals 6MW and a generator efficiency of 97%, an estimation of the average daily flow required to achieve the daily output can be achieved. Time spent not at rated flow, at each 5% increment of the rated flow, will then be multiplied by the corresponding difference in power that can be achieved with a more efficient Kaplan turbine, hence determining the economic benefit. It is assumed that there will be a minimum of 0.1 hours spent at each flow rate in the analysis. Alongside this an investigation into the impact contingency rate has on the cost-benefit will be undertaken. A 30-year period for the analysis was selected for the analysis, as it is the economic life of a Kaplan turbine (Goldberg and Lier, 2011).

Utilising ‘goal seek’, in Excel, it was calculated that for the project to be economical over the 30-year period a minimum of 3.8MW/day difference would be required at the current estimates. An initial analysis revealed that for 6 hours ADOT, it would not be feasible to achieve payback from the variation in flow from the rated unless contingency rates were -45 % or less, i.e. the project cost must be less than £650,000. Therefore, for the sensitivity analysis, hours immediately above this time were used; contingency costs were varied from 25% to -25% to get a full understanding of the cost impact. Results are shown in Table 5 and 11 and 12 of Appendix E.

The analysis found, however, that the question being posed in this CBA is, in fact, two questions. The first being determining the maximum time at rated flow, that would achieve the estimated ADOT, meet the daily average output, and achieve payback. To which it is found that as the number of predicted ADOT increases, more money can be made from the Kaplan turbine. This is a result of the time spent at rated flow being forced to drop in order for more time to be spent at lower power outputs to make the constraint of 32.2MW. This then prompts the second question of determining the minimum time required not spent at rated flow which would achieve payback, meet the estimated operational time and meet a minimum of the yearly daily average output. Results are shown in Table 12, Appendix E. Yet, as expected as the operational time increases then a higher daily average output increases; which in some respect moves away from the validity of the analysis.

The effect of contingency costs revealed, in the preceding case, that as contingency costs move from 25% to -25%, maximum time at rated flow increases to a maximum of 1 hour more than the original time. Whereas for the first analysis contingency costs reduced the ratio of cost/benefits by a maximum of 30%, which occurred at an estimated time of 7 hours. Due to the similarities between the results negative contingency costs can be found in Appendix E.

Table 5: CBA of Proposed Kaplan Solution in Respect to the Maximum Rated Flow Rate Required

Average Daily Operating Hours			7 hours			8 hours			9 hours		
Contingency Rate			**25%**	**15%**	**5%**	**25%**	**15%**	**5%**	**25%**	**15%**	**5%**
% of rated flow rate	1	Time Spent at Flow Rate	3.88	3.88	3.88	3.26	3.21	3.16	2.62	2.62	2.63
	0.95		0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.9		0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.85		0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.8		0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.75		0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.7		0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.65		0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.6		2.45	2.45	2.45	4.04	4.09	4.21	5.61	5.61	5.59
Costs/ Benefits			**0.94**	**0.88**	**0.82**	**0.65**	**0.60**	**0.55**	**0.5**	**0.47**	**0.42**

Table 6:Contingency Rate Characteristics

Contingency Rate	25%	15%	5%	-5%	-15%	-25%
Project Cost (£Million)	1.21	1.113	1.016	0.920	0.823	0.725
Average Daily improvement (MW)	2.9	2.6	2.4	2.2	2.0	1.88

4.1.5 - Considerations & Potential Impacts

When undertaking a turbine replacement, a number of potential impacts and considerations must be understood and will be discussed in the following section. One major consideration not considered during the technical analysis of the design of the Kaplan turbine is the impact of cavitation on the turbine as a result of prolonged higher outputs. As found in the literature review, in uprating of the turbine at Akosombo hydroelectric plant, cavitation occurred during periods of high flow rates due to a compromise in the band profile to fit into the bottom ring profile (Mielke *et al.*, 2005). Further CFD models should nevertheless be conducted to determine the potential onset of cavitation. A detailed hydraulic transient analysis should be conducted to determine the impacts the proposed turbine will have on the components in context of the pressure and prolonged higher output (BCK Mishra, 2015). Increase in prolonged higher power output will also have an impact on the generator, and the design loading capacity of the installed generator should be consulted. In return, the design specifications of the guide vane servomotors, such as the design pressure, governor control design, size, and hydraulic pressure must be consulted prior to instalment. The change in weight from the adding of the extra components required to make the turbine blades adjustable must be considered in respect to the civil structures and the additional stress and bending that could occur.

Consideration should be made towards the fish population when implementing this design, where the change in compression through the turbine could have an impact on the fish population; experiments may have to be undertaken to understand what level of impact it may have (Martinez *et al.*, 2018). However, the impact should be minimal, due to their being fish ladders installed at Carsfad and Earlstoun (Scottish Power, 2018a). If a retrofit was to be made to Drumjohn power station, where a fish ladder does not lie, then the design of the Kaplan turbine may have to change to incorporate fish flowing through it. If not, the potential impacts could occur not only to the fish population but to the turbine itself, such as loss in efficiency and cavitation (Martinez *et al.*, 2018). In a study by (Martinez *et al.*, 2018), investigations were undertaken to determine the impact on fish from retrofitting a Kaplan and turbine; results highlighted that operating of the newly installed Kaplan turbine should run as close to atmospheric pressure as possible.

SCADA should also be installed in cooperation with the adjustable blades, to allow analysis of the performance, enabling further investigation of the optimal blade angle for varying flow.

4.2 - Installation of a Modern Francis Turbine

4.2.1 - Reasoning

During the conducted site visit to GHES, it was found that there had been little or no runner design upgrading to the Francis turbines located at Glenlee, Kendoon and Tongland. Resulting from the literature review it was found repeatedly that runner design prior to the 1960's can benefit as much as 30% through modernising and replacing of the unit (Bureau of Reclamation, 2010). This was found to be due to advances in the field of CFD, which allow blades nowadays to be optimally designed for efficiency, as well as the use of modern material such as ASTM A487/ A743 CA6NM Stainless steel, that prevent the onset of cavitation (Mesa Associates Inc. and Oak Ridge National Laboratory, 2011a). Further evidence on the benefits of upgrading of the runner was found in case studies where improved runner design was apparent across the majority of the upgrading and refurbishment projects undertaken by Andritz hydro (Andritz Hydro, 2012). Currently, at Glenlee power station, the efficiency of Unit 1 is peaking at 91% while Unit 2 peak efficiency is 90%, revealing that there is room for potential efficiency improvements (Scottish Power, 2018b).

With that been said the following section will highlight in further detail the potential energy output difference that could be achieved for the Francis turbine installed plants. A technical analysis will also be included with the aim to estimate the potential improvement of the runner performance through analytical calculations. While there are several design improvements that could also be made to the Kaplan turbines in the scheme, this section will focus solely on Francis turbines, as the Kaplan turbines have already been considered in Section 4.

4.2.2 - Technical Analysis

In determining the potential increase in efficiency from a Francis turbine, the equivalent analytical approach taken to that of the Kaplan turbines was undertaken – adjusting the equations for the context of a Francis turbine. The goal for this was to determine if that by changing the blade angles, an increase in efficiency could be seen. Yet, it was determined due to the accuracies in component and blade losses, required in order to reveal the true efficiency improvement for the unit, are not apparent in the calculations. Consequently, effort turned to seeking another approach that could produce realistic results and which would allow the parameters of the installed turbines at one of the Francis turbine-installed HPP to be considered.

A further literature review was conducted, and it was concluded that the methods developed in the paper by J.Gordon (2001) to be most suitable for the objectives of this project.

In the study by J.Gordon, approximately 56 Francis turbine runners were investigated for their efficiency characteristics between the period of 1908 and 1998, with the goal being to capture the relationships between the turbines in regard to efficiency. The paper produced a set of methods and approaches derived from the case studies studied, that could be used to determine the expected efficiency curves, for a given turbine characteristic. Most importantly, in the context of this project, the author derived a method of calculating potential efficiency improvements in respect to the age of the turbine, by capturing the trend in technology advancements of hydraulic turbine design. Gordon's efficiency calculation was used in a case study involving 22 HPPs to determine the accuracy of the author's method; results showed that the method had a root mean squared accuracy of 1%.

For the following technical analysis, J.Gordon method of calculating the peak efficiency for a given turbine will be carried through in the context of a Francis turbine installed at Glenlee HPP. Glenlee was chosen due to the accurate data available for the site, and which will allow calibration of the curves developed through (Gordon, 2001) method. Unit 2 was chosen for analysis due to it being the least efficient of the two turbines at the station, and where modern turbine replacement would be most beneficial.

From the analysis of case studies, the following equation for peak efficiency was derived, based upon the instalment date, specific speed and size of the turbine, for a Francis turbine.

Equation 6

$$\eta_{peak} = A - \eta_{year} - \eta_{nq} + \eta_{size}$$

Constant A is defined as 0.9187 and is derived from the given data in order to give a foundation in the context of peak efficiency. The following parameters each have an associate equation to them and will be further described**.** Following the constant η_{year} relates the turbine in question to its commission date and thus adjusts the peak efficiency to that expected at that time. It can be calculated using the following equation, where constants b and x for a Francis turbine are estimated to be 187 and 3, and the instalment year is taken as 1935 for Glenlee.

Equation 7

$$\eta_{year} = (\frac{ycurrent - y}{B})^{x}$$

Equation 8

$$\eta_{year} = (\frac{2007 - 1935}{187})^{3}$$

For current year, 2007 is used as this was the year the data for the Unit 2 was recorded. Preceding the year efficiency equation, the equation that takes into context the specific speed follows, which adjusts the peak efficiency to the maximum efficiency at the given speed. The following equation calculates this, wherein the context of a Francis turbine C is defined as 52, D as 292 and z is equal to 1.017. Rated head, flow rate and speed are defined as 89.5m, 14.78 m^3/s, and 428.6 rpm, based on the parameters present during optimum efficiency of the unit.

Equation 9

$$n_q = rpm\ Q^{0.5}\ H_r^{-0.75}$$

$$n_q = 56.107$$

Equation 10

$$\eta_{nq} = ((\frac{nq - C}{D})^2)^z$$

$$\eta_{nq} = 1.7114 * 10^{-4}$$

The last equation required for the determination of the peak efficiency is that for η_{size}, which adjusts the peak efficiency based on the size of the turbine. Throat diameter of the turbine is defined as ‘d’ and is taken from drawings to be 1.468m (Scottish Power, 2018b).

Equation 11

$$\eta_{size} = (1 - A + \ \eta_{year} + \eta_{nq})(1 - 0.789d^{-0.2})$$

$$\eta_{size} = 0.037$$

$$\eta_{peak} = 0.9187 - \ 0.05707 - 1.7114 * 10^{-4} + 0.037$$

$$\eta_{peak} = 89.87\%$$

Peak efficiency recorded during data recording in 2007, was defined as 90.58%, approximately 0.71% less than that calculated. Following the (Gordon, 2001) method, the recorded efficiency during 2007 of 90.58% would be achieved if the turbine was installed at 1940, rather than 1935, indicating the turbine has been refurbished or it has been well kept; therefore, for the following analysis 1940 will be used instead of 1935. Furthermore, the following analysis will use 2018 as a current year as an estimate of the efficiency today.

Using the following equations, efficiency curves can be estimated based on the peak efficiency, allowing comparison against that recorded at the site. Q_{snl} is defined as the specific flow rate which enables the runner to operate at synchronous speed, enabling the power station to be taken online (Gordon, 2001).

Equation 12

$$Q_{snl} = Q_{rated*} \left(\frac{n_q}{570}\right)^{1.2}$$

Equation 13

$$\eta_q = \eta_{peak} - \Delta\eta_{peak}$$

Equation 14

$$\Delta\eta_{peak} = \eta_{peak} \left(1 - \frac{Q_{snl}}{Q_{peak}}\right)^{-k} \left(1 - \frac{Q}{Q_{peak}}\right)^{k}$$

A comparison between the estimated curve can be seen in Figure 29. It should be noted, however, that the efficiency beyond 5 m^3/s for the unit was not recorded, therefore a continuation of the curve was assumed. Although, from 10 m^3/s until 5 m^3/s, the efficiency had been diverging; this could, however, be due to the Q_{snl} being defined for the estimated unit and not for the recorded. Using equations, defined in Appendix G, allowed the determination and comparison of the power output from the estimated efficiencies against the recorded power output from the generator at each flow rate, assuming a generator efficiency of 97%. The recorded power output from the generator allowed the initial calibration of the runner speed in the equations, through the use of 'goal seek' on Excel, to ensure the power output from the calculated efficiencies would be comparable. Figure 30 highlights the difference between the calculated and the recorded power outputs against flow rate.

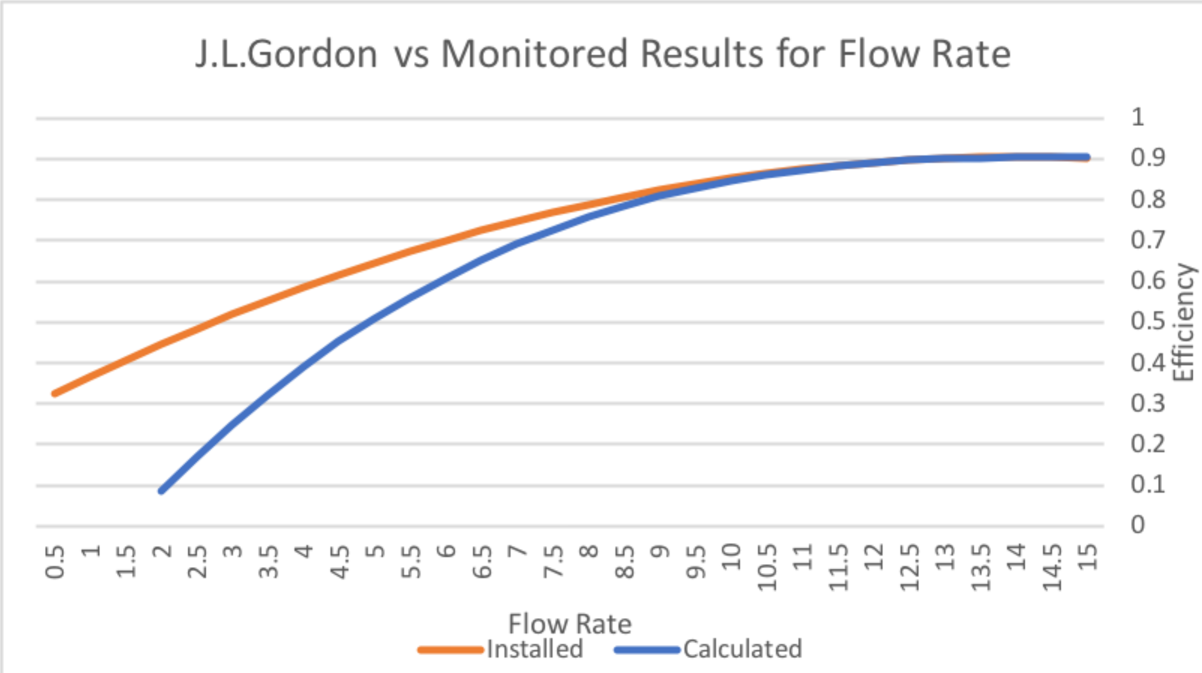

Figure 30: Installed vs Calculated Efficiency Curve for Glenlee

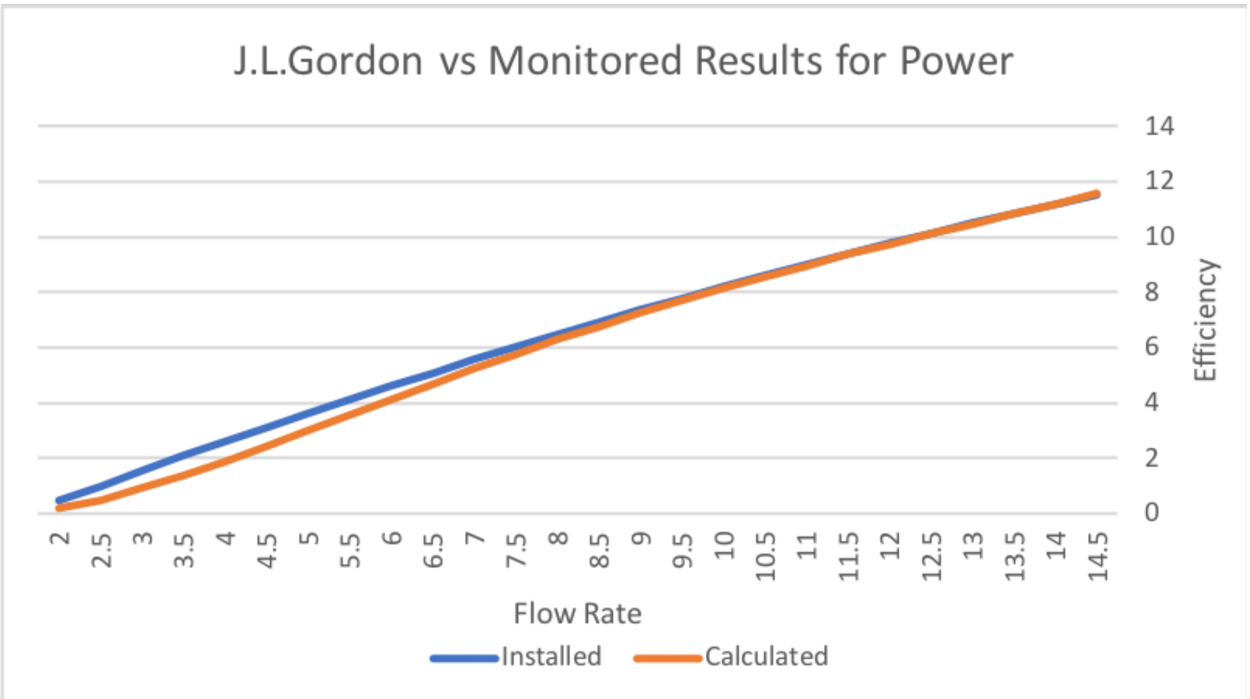

Figure 31: Installed vs Calculated Power Curve

Once more using the equations defined by J.Gordon it is possible to estimate what would be the potential peak efficiency of a Francis turbine installed at Glenlee if using the latest technology. Taking the differences in efficiency between the calculated and recorded, a calibration method, similar to that used during the Kaplan turbine, can be used to give a more accurate estimation of what the potential power output and efficiency improvements could be. Although similar to the Kaplan turbine, the rated flow for synchronous speed is not known and accuracy of the curve is limited to once more to 60%. Figure 31 displays the efficiency curves of the estimated efficiency for 2018 and for a modern runner, after calibration, where peak efficiency at the rated flow rate is determined to be 0.9404% for a modern runner. From this, an equivalent power curve can be derived and is shown in Figure 32. Efficiency improvements of 5.04% when compared to the estimated efficiency today, reflect that stated in Section III, specifically that by (GE, 2018).

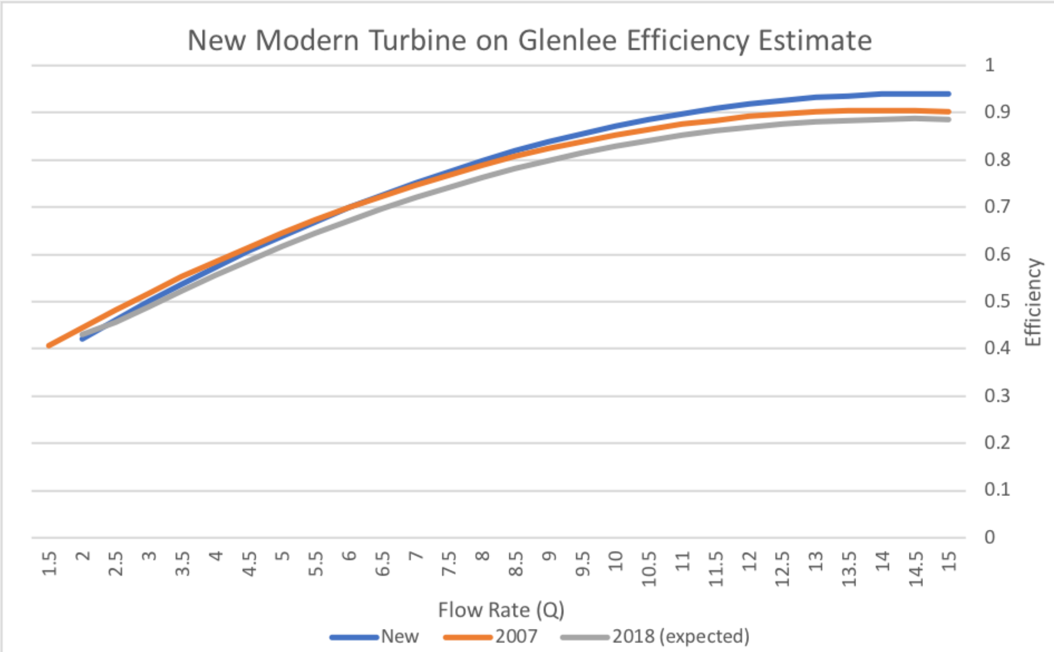

Figure 32: Predicted Modern Turbine Replacement Efficiency Curve for Glenlee

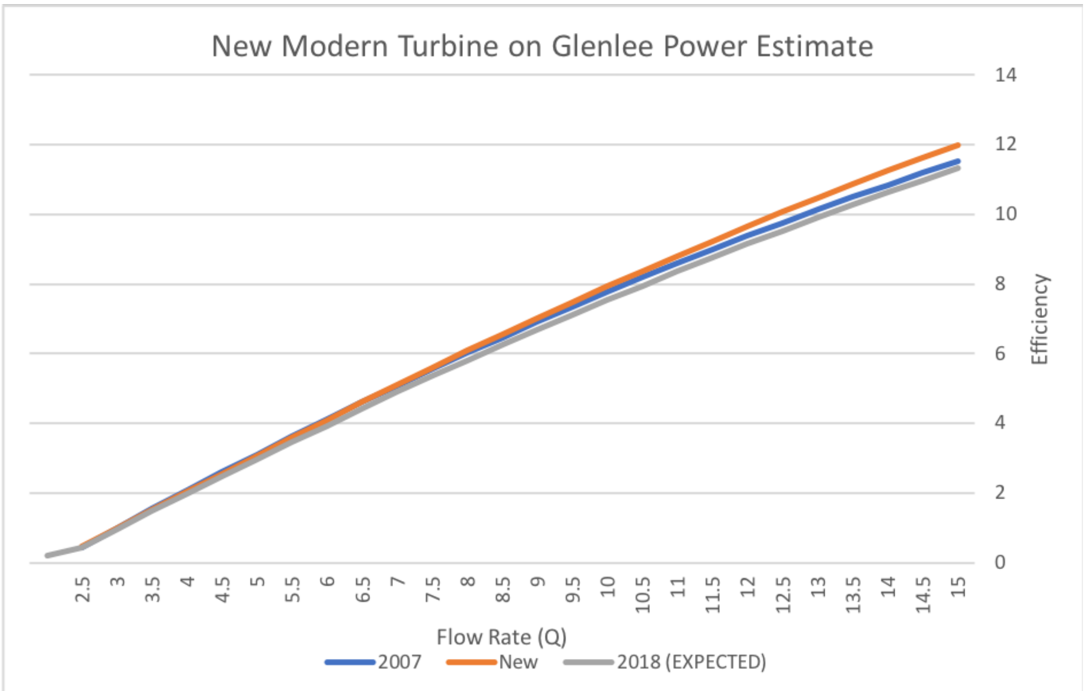

Figure 33: Predicted Power Curve for a Modern Francis Turbine Replacement at Glenlee

4.2.3 - CBA

To determine the feasibility of installing a new Francis turbine into Glenlee, a cost-benefit analysis is achieved. To estimate the project costs associated, expenditure recordings of a Francis turbine replacement, at a site with a similar net head, 146m to 121m and size was consulted, with those relevant shown in Table 7 (NLine Energy, 2016). The paper is a preliminary investigation into the possible rehabilitation of an existing HPP in San Diego, which was built in 1987. Since the project was undertaken in the US, currency was exchanged at the current rate of writing, where numbers were rounded to the nearest thousand.

For this example, labour costs, including time, are assumed to be included in the installation cost estimated by the author; although costs do align with that estimated in the Kaplan installation. As a result, project time will exclusively be in respect to the outage time. While not explicitly mentioned in the paper, outage time recorded by the author will be from the date recorded for components arriving on site until project start-up - equating to an outage time of 12 weeks. Design & engineering services for replacement of a Francis turbine, including construction management services, is estimated by the author to be 17% of the total construction costs. Contingency costs are taken as 25% of the total construction and engineering services costs.

A strike rate of 9.43 p/kWh was used, as discussed in Section 4. Maintenance difference as a result of the installation of the turbine is assumed to be 2.5% of the project cost, based on the estimation by (IRENA, 2012). Re-installation of the SCADA system is assumed in the installation cost. Discount factor and interest rate are as the same than that taken for the Kaplan turbine CBA.

Component costs are calculated using an equation derived by Aggidis *et al.* (2010)**,** which derived the equation as a function of head and flow rate based on case studies, similar to the method used by (Gordon, 2001). Aggidis *et al*. developed a series of equations for electro-mechanical turbine costs based on statistical data obtained from manufacturers for small HPP, HPP of capacity between 10MW -1MW (renewablesfirst.co.uk, 2017). The derived equations can be used to estimate the cost for a Francis turbine, where flow rate and head are again 14.78 m^3/s and 89.5m.

Equation 15

$$C_{Francis} = 50000 * (Q * H^{0.5})^{0.52}$$

$$C_{Francis} = £652{,}641$$

The price was estimated to be approximately £653,000, however the equation for the price was developed by the author during 2008, hence, taking it to account inflation rate at an average of 2.7%, this would equal today in 2018 as £827,833 (Bank of England, 2017). To verify this method a more recent graph highlighting the cost of a Francis turbine in USD/kW against maximum flow rate by a different author is consulted Appendix H (SWECO Norge AS, 2012). For this graph the estimated value turbine is approximately 190 USD/kW, equalling to $1,140,000 or £885,096 - less than 6.5% different (SWECO Norge AS, 2012). For the following analysis, the higher of the two costs will be taken. Comparing this against the turbine cost estimated in the case study there is a cost difference of 13%, between the 1.5MW and 20MW turbines.

Table 7: Cost Estimations for a Francis Turbine Replacement

Item	**Costs (£)**
Component	885,000
Mobilisation & removal of existing turbine	305,000
Installation & Shipping	102,000
Commissioning & Testing	47,000
Design & Engineering Services	227,000
Construction contingency costs	392,000
Lost Revenue	522,800
Total	£2,418,000

Benefits are taken as the difference in operational benefit, and the reduction in maintenance. During this investigation the daily and seasonal operational could not be obtained, therefore, for the first analysis, a time similar to Carsfad will be used, in known that the role of the GHES is to meet the peak load, where a sensitivity analysis to follow. Furthermore, an assumption that the HPP runs at rated flow the entire time of operation, therefore must be made; at a feed-in rate of 9.43 p/kWh**.** The result of the technical analysis has shown that a possible 0.41MW can be achieved at the rated flow rate and head, with a new Francis turbine. Assuming once more a generator efficiency of 97%, this equates to an extra 823075 MWh/year, which at a strike price of 9.43 p/kWh compares to approximately an extra £140,000 per year, and a reduction in maintenance of approximately £62,000 per year. Once more a 30-year period for the analysis was selected for the analysis, as it is the economic life of a Francis turbine (Goldberg and Lier, 2011).

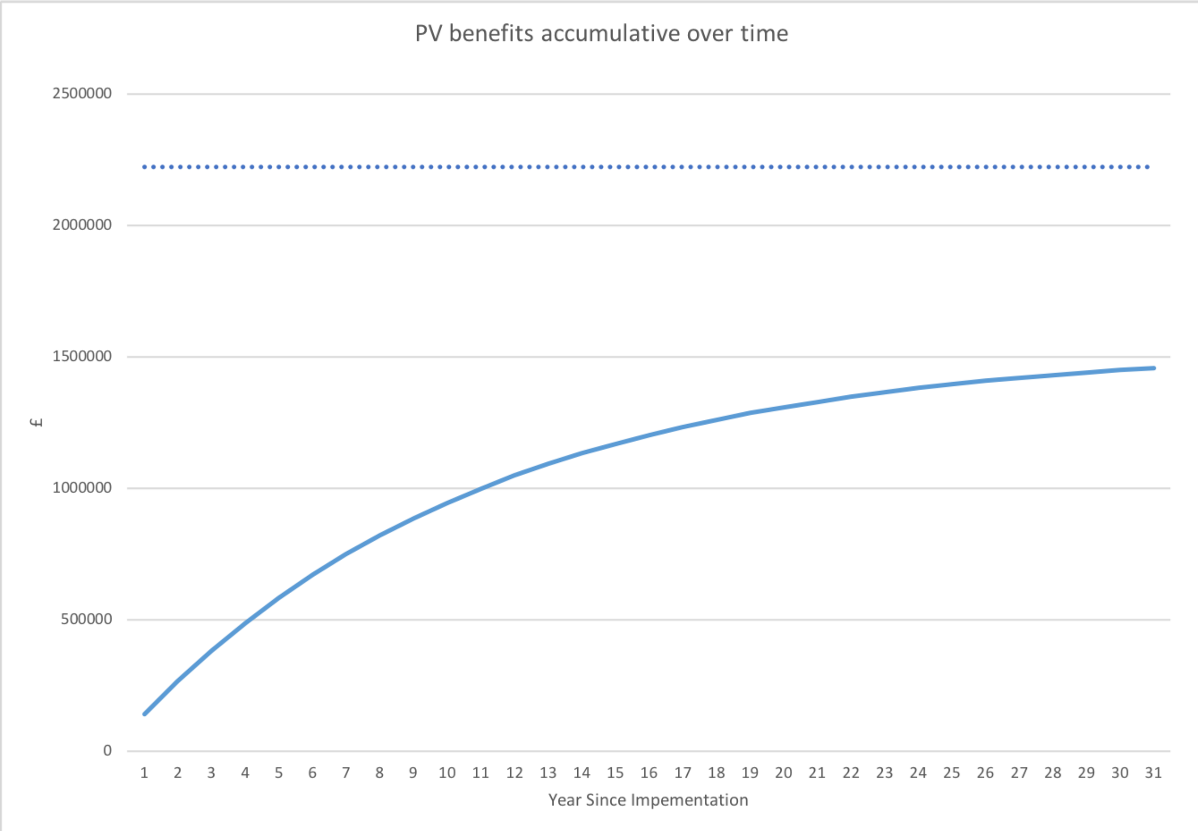

Figure 34: PV Costs/PV Benefits Based on Current Estimates

The CBA has shown that the PV costs/ PV benefits equate to 1.7, with a discount factor of 10%, consequently meaning that the turbine would never achieve payback. While the costs estimated are based on a similar site, components and labour costs may vary, therefore a sensitivity analysis must be achieved. The following sensitivity analysis will examine the effects of contingency costs, lost revenue and discount factor, in regard to the cost-benefits. As previously mentioned, a sensitivity analysis will be completed in respect to the average daily operational hours.

Figure 36 highlights the change in discount factor from the current 7.5% to interest rate, 2.5%, only. Varying the discount factor has shown that for the project to be economical over the 30 years, a discount factor of 2.5% or less is required. The role of the discount factor is to give context to future interests, where benefits occurred closer to the installation data are worth more than they would be at x amount of time down the line.

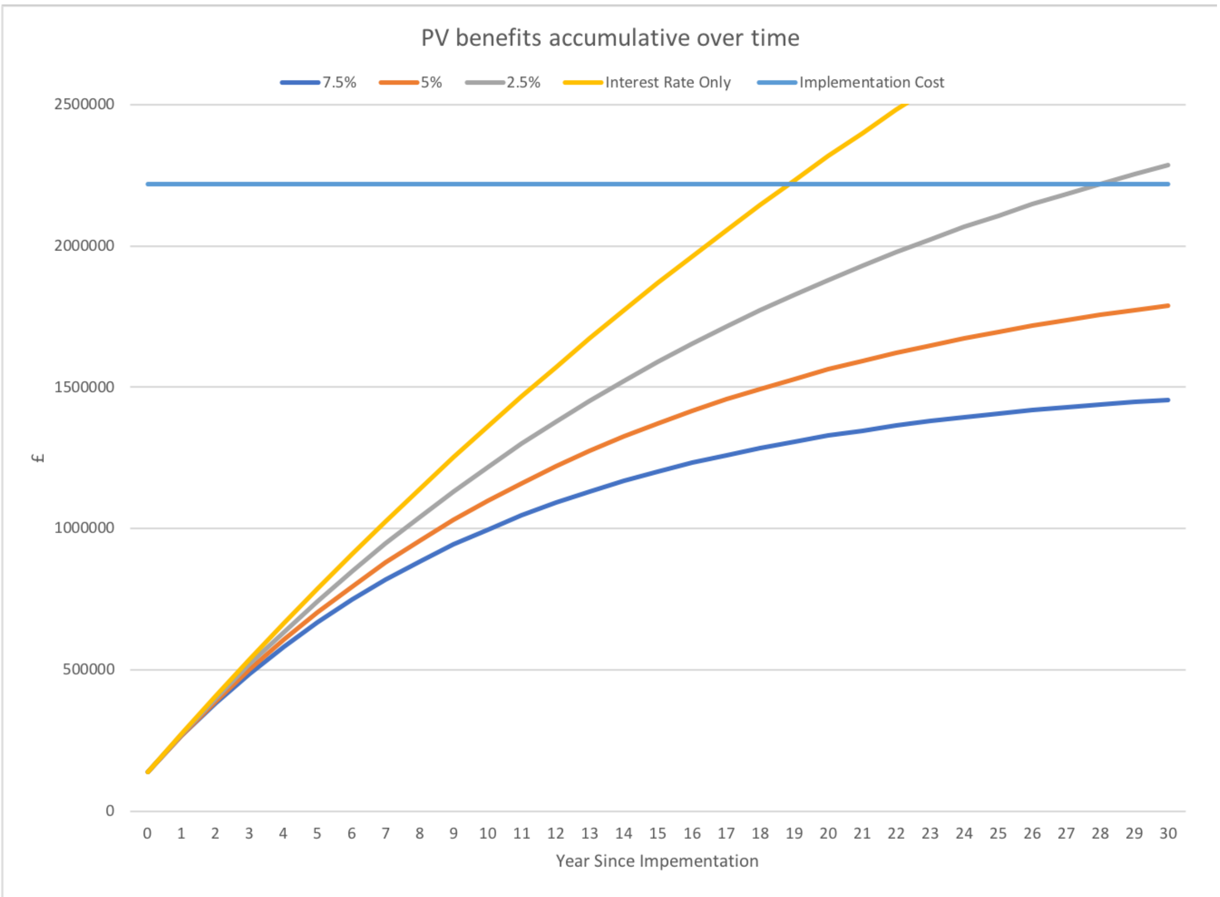

Figure 35: Discount Factor Sensitivity

To understand the influence the estimated installation time and contingency rate has on the economic justification of the project, a sensitivity analysis was conducted. It was immediately realised that the contingency rate had to be below 0, due to none of the contingency rates in between resulting in a positive economic result. Therefore, the analysis was run between 0 and – 50%, or in other words between the estimated cost and half of the cost calculated. Weeks are varied between 3 months to 1 month, the lowest found time in the literature review to complete the project, and at a discount rate of 7.5% - results are shown in Table 8.

Results have shown that at the current estimated project time, the cost would have to be below 64% to that estimated, equating to a total project cost of £1,100,000. For the quickest installation possible, it would have to be below 40% that of the estimated cost to make it viable.

Table 8: Project Time Sensitivity

Installation Time	12 weeks								
Contingency Rate	0	-5	-10	-15	-20	-25	-30	-40	-50
PV costs / PV Benefits	1.54	1.5	1.47	1.43	1.4	1.36	1.32	1.2	1.14
Installation Time	8 weeks								
Contingency Rate	0	-5	-10	-15	-20	-25	-30	-40	-50
PV costs / PV Benefits	1.46	1.4	1.39	1.35	1.31	1.26	1.22	1.1	1.02
Installation Time	4 weeks								
Contingency Rate	0	-5	-10	-15	-20	-25	-30	-40	-50
PV costs / PV Benefits	1.38	1.3	1.3	1.25	1.21	1.16	1.11	1	0.9

An investigation was further run to determine the efficiency difference which would be required to make the project justifiable. Using Gordons method once more, in order for the project to be viable the efficiency of the turbine would have to drop to below 86%.

To complete the sensitivity analysis, a study into the daily operational time required to make the project feasible, has been undertaken with the results highlighted in Figure 37.

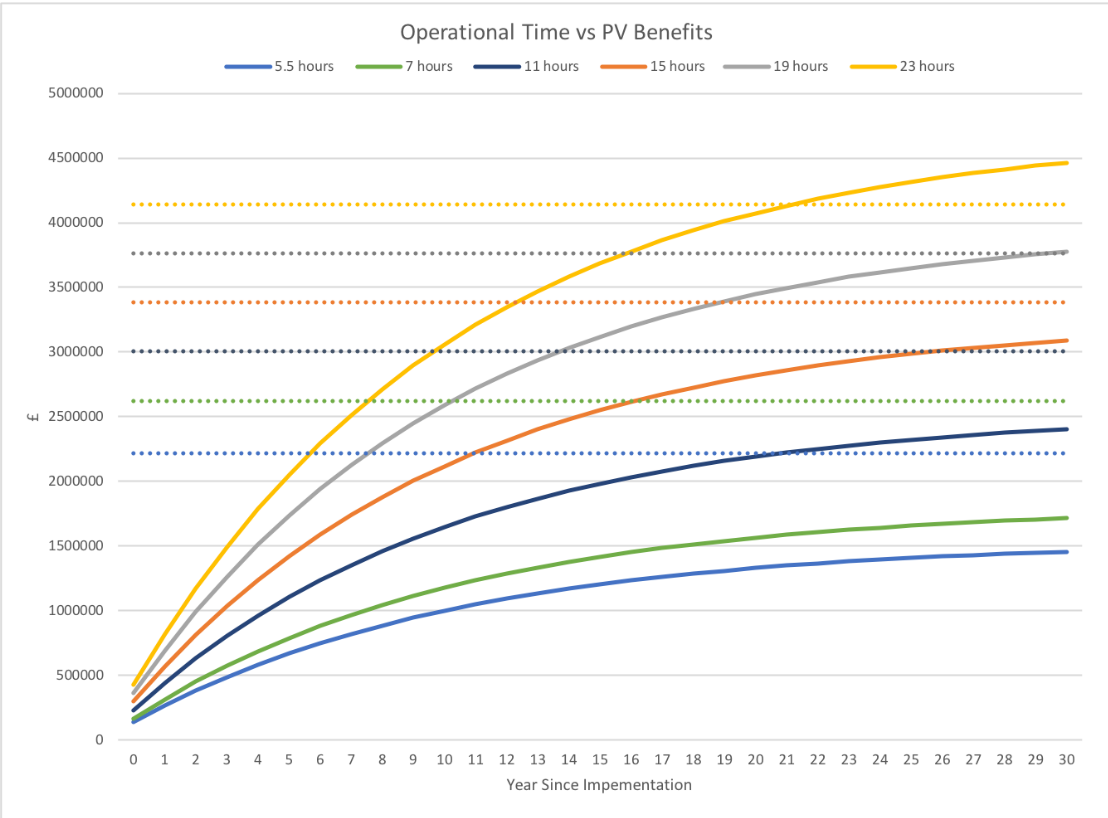

Figure 36: Operational Time Sensitivity

Consequently, as the operational time increases, then so does the outage costs. Results have shown that at the current discount factor, contingency costs and estimated time, the power plant would need to run for an average of 19 hours per day to make the project worthwhile. Payback within the estimated economical life of the instalment would occur at an operation time above 19 hours, where 23 hours is shown as an example.

Kendoon & Tongland, were not further investigated for turbine replacement, due to the turbines being estimated to be within 10% of each other and the lack of information on expenditures for stations with smaller heads than that found.

4.2.4 - Feasibility

While the cost-benefits of the project have proven not be feasible, this section will aim to further understand the process of the project and to investigate whether or not there can be any further methods of cost-cutting that could make the project feasible.

It is known from case studies that a project of this type is feasible and that if designed correctly, the upgraded runner design should fit inside that of the existing space - except if the decision is made to increase the diameter of the turbine, in which further civil works must be achieved. Steps included in removing the runner is dependent on the initial design on the turbine, and the surrounding facility, but essentially there are two approaches, the upward or downward approach (Chhetry, 2017). The upward approach involves taking out the guide vanes and their associated mechanisms, taking away the intermediate and turbine shaft, as well as the head cover and the associated bearings and seals. The more popular dismantling approach is to remove the runner downwards, which still involves removing the turbine from the intermediate and turbine shaft, through the removal of the turbine bearing and associated shaft seals, bolts and covers, as well as the draft tube. The benefit of both of these methods is that it doesn't involve the removal of the generator, however as mentioned before it can be costlier due to the time required to remove all of the components. Moreover, there are a lot of crucial steps required that can potentially increase the labour time and resultantly costs, such as the removing and re-installing the guide vane linkage, in which the close tolerances are required to meet the design criteria or removing the generator oil reservoir.

The method of dismantling, on the other hand, can open up opportunities to enhance components required in the dismantling and not only the runner. For example, in the upward approach, guide vanes can be re-profiled for optimisation, or even have their material changed to CA6NM stainless steel, while bearings can be removed of any potential defects (Mesa Associates Inc. and Oak Ridge National Laboratory, 2011a).

An alternative and quicker method of upgrading the runner was achieved during the replacement of runner blades inside a Francis turbine, at the Canadian HPP in Manitoba (Potter, 2013). The method involved plasma cutting at the crown and band seals of the runner and simply removing the blades from the runner. After grinding and cutting the new runner blades to meet the geometry of the runner, the new blades were simply established back into the runner and welded, to ASME VIII weld standards. The new blades were re-designed using CFD for optimal efficiency. The method of simply replacing the blades may open further opportunities for cost-cutting; the exact component costs of a runner were not known and therefore a CBA was not investigated.

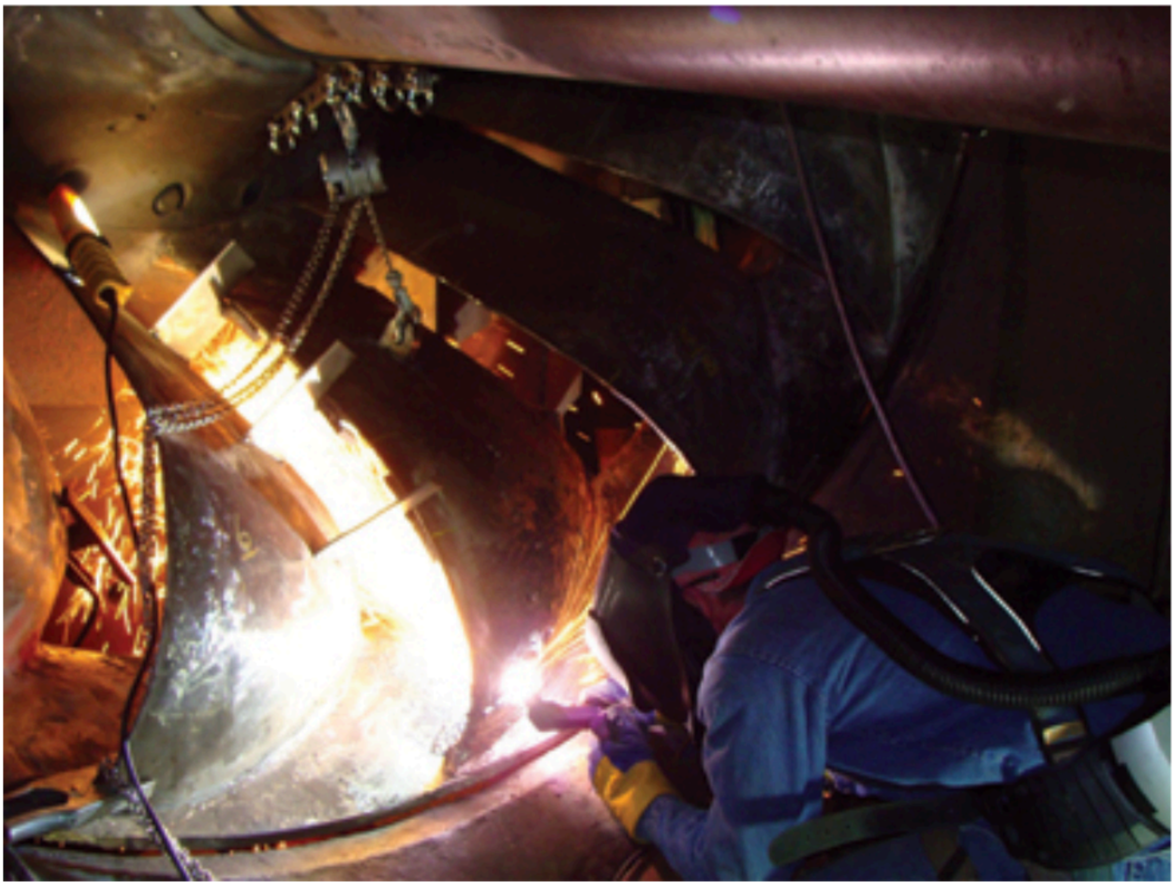

Figure 37: Direct Removal of Francis Turbine Runner Blades (Potter, 2013)

Another cost-saving opportunity could lie in the use of robotics to undertake reshaping of the turbine runner, without the removal of any components. A key ambassador of this method is Hydro-Quebec, which have modified 14 Francis Runners in the region until 2012, using their portable six-axis robot "SCOMPI" (Bruce Hazel, Jean Cote, Yvan Laroche, 2011). A typical runner modification can include thickening, thinning or even lengthening the profile of the blades in the required areas through the robot's capabilities of grinding and welding. However, the procedures that robotics can achieve are normally essentially only for relatively small efficiency increases, with a maximum possible efficiency increase of 1.5%. Although the method of not removing any components and the modification time that can be achieved makes the modification viable (Bruce Hazel, Jean Cote, Yvan Laroche, 2011). To determine the economic feasibility of this, a quick CBA is realised in the following section.

4.2.5 - In Situ Modifications

The details of utilising robotics to realise small efficiency improvements in large hydraulic turbine machines, specifically SCOMPI, is discussed in detail in the paper by (Bruce Hazel, Jean Cote, Yvan Laroche, 2011). It is stated in the paper that repair work for improving the efficiency of hydro turbines as much as 1.5%, which normally takes months and at a large investment, as seen in the above analysis, can be achieved in a matter of weeks. To quantify this, the efficiency curve for the 2007 readings, assuming no loss in performance until the present day, was re-calculated using a maximum increase in efficiency of 1.5%. Once more, assuming the maximum change in output, is at the rated flow, to be constant and for it to run at the rated value at 5.5 hours a day, 7 days a week, for the entire year. This resulted in a performance benefit of 0.17MW or 341275 MWh/year equating to an economic benefit of £32,000 per year. Since the modification will be done without removal of the turbine, the removal costs will be null, whereas the commissioning and testing of the machine are taken to be £25,000, the maximum cost in the internal paper by (Mott MacDonald, 2004). Commissioning costs are also expected to be less due to the machine already been established, where no fitting is required. Total project time for the modification is taken to be 3 weeks, as based on the estimate from (Bruce Hazel, Jean Cote, Yvan Laroche, 2011). Design & engineering services costs were taken to be double that of modern turbine replacement, 0.34% of total component costs, due to the custom design, re-coding of the robot for new geometry, and CFD required. Contingency costs again were taken as 25%, and maintenance benefits again were taken as 2.5% of the total installation cost. Using 'goal seek' on Excel the installation & component costs required to make the project economical just over a 30-year period, was calculated to be £163,000.

Due to the small time estimated for the modifications to take place, the repairs could be taken during periods of low demand, which could drastically lower the revenue lost. If this was the case, then payback of the installation could be increased by 18 years, or the savings could be made to make the project justifiable. Further investigations are required to determine the true cost of the project.

Table 9: In-Situ Cost Estimation

Item	**Costs (£)**
Performance Benefit	32,000
Mobilisation & removal of existing turbine	0
Installation & component costs	163,000
Commissioning & Testing	25,000
Design & Engineering Services	64,000
Construction contingency costs	62,873
Lost Revenue	131,000
Total	£445,000

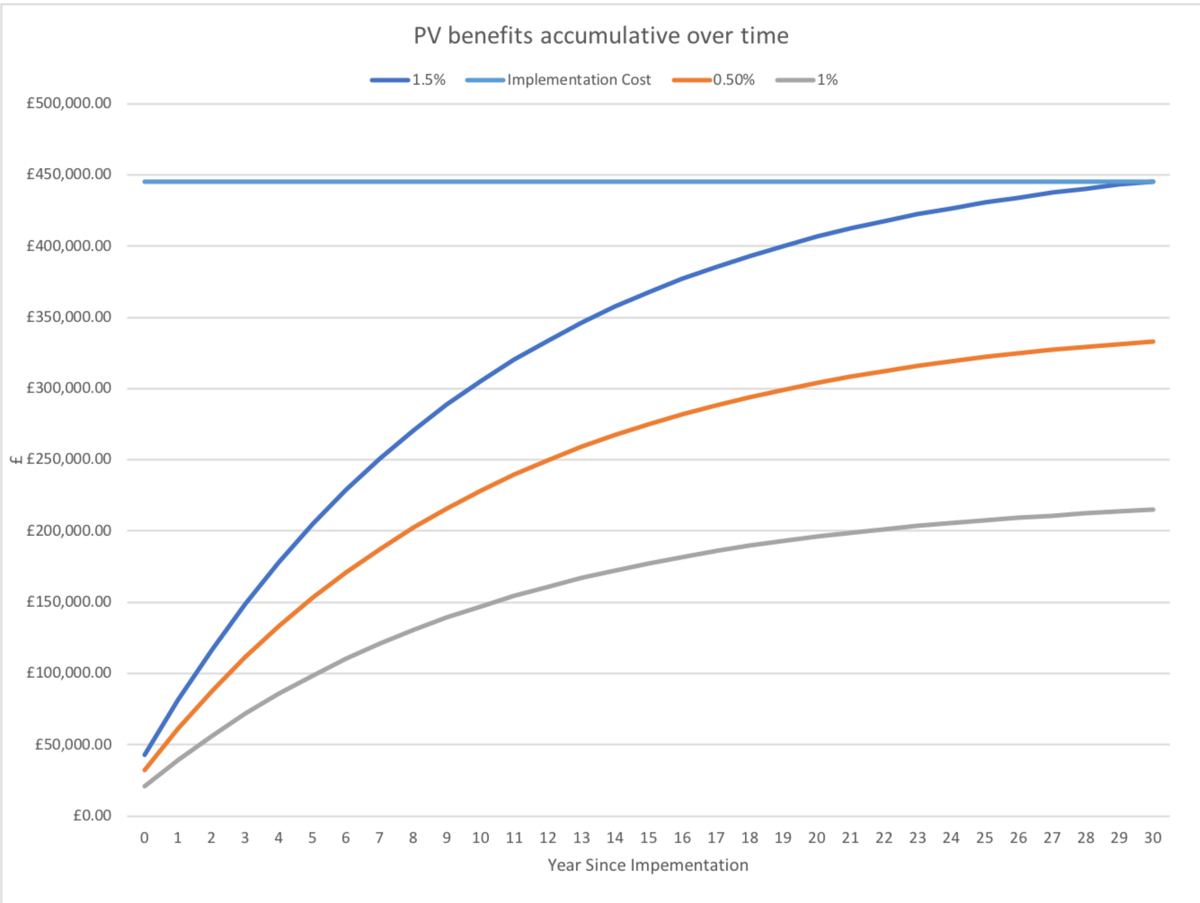

Figure 38: In-Situ Approach Efficiency Improvement Sensitivity

4.2.6 - Considerations & Potential Impacts

Similar to the Kaplan turbine, calculations in this matter have not considered the potential increase in cavitation that can arise from a change in runner design, therefore, future work should study the effects regarding this topic. Similarly, the impact that start and stop fatigue load cycles can have on the newly designed runner, has not been considered in this project (Singh, 2013). Moreover, further considerations should investigate the impact that guide vanes have when passing the runner and the development of flow fluctuations which can have an impact on fatigue vibration stress (Mesa Associates Inc. and Oak Ridge National Laboratory, 2011a). An FEA and CFD analysis should be conducted to see the dynamic and static stresses acting on the new runners in order to determine the reliability of the runners and resultantly the life. The opportunity of replacing the material of the runner blades to ASTM A487/A743 CA6NM should be considered in this project, due to the materials capability of resisting wear and cavitation (Mesa Associates Inc. and Oak Ridge National Laboratory, 2011a).

Resulting from increased production through efficiency improvements, considerations must be made to those affected by the increased output. One such consideration is the draft tube, where an increased discharge could result in severe backflows and instabilities (Bernard *et al.*, 2004). Moreover, considerations have to be made to the runaway speed, axial thrust and hence the pressure rise on the machine subject to the increase output from the turbine (Singh, 2013). Singh et al. goes on to describe the effect the guide bearing will have from the increased load, where the author mentions that the hydraulic unbalanced forces have to be taken into consideration. Similarly, considerations must be taken for the shaft seal, which could result in increased levels of leakages. It would be recommendary to continue monitoring on the system post uprate.

If the blades are to be removed and welded back on, then considerations must be made to the weldability and must adhere to weld standards in order to avoid potential defects that can arise in weld (Potter, 2013). Additionally, the effect of the bending stress created from the weld to the band seal, which can increase from the effect of notch effects, should be considered (Potter, 2013).

Section V - Discussion

The overall aim of this project is to investigate retrofit solutions for the GHES that would improve the efficiency and/or the output of the plant. Further to a site visit, and an extensive literature review, potential scope was found for modernising of the Francis turbines on site and for retrofitting a full Kaplan turbine in replace of a semi-Kaplan turbine at the Carsfad, Drumjohn and Earlstoun HPPs. Consequently, a detailed appraisal of the solutions with respect to the technical, practical and economic feasibility followed.

For the technical analysis of the Kaplan turbine, a study into the equations that govern hydraulic turbine design was conducted to allow calculations of the performance benefits. Due to the difficulty of calculating turbine losses using the empirical formulae, calibration to the original efficiency curve gave an estimation of the expected losses per incremental change in flow rate. Expected efficiency curves for a full Kaplan turbine were produced using this method which revealed that for the majority of the change in flow until rated, an adjustable pitch blade could maintain close to peak efficiency. This reflects that found by (Farell and Gulliver, 1987), between the periods of rated flow to 60% of rated flow. This method assumes that the level of calibration of the calculated losses to the existing curve is the same as that experienced during the manipulating of the blade pitch. However, a constraint stopping the efficiency going above that of the rated efficiency was deployed, as it is unlikely that a Kaplan turbine would go above its rated efficiency below its rated flow– except in cases of poor design. While this is not the true case in the application, this method allows respectable results that allow a CBA to take place, within the time constraints of the project. Further work should investigate through CFD the turbine runner losses expected in an adjustable blade Kaplan design for the Galloway Hydros.

A feasibility study was conducted to determine the best method for retrofitting the Kaplan turbine into the plant, where two methods were found. To either retrofit the existing hub with the components required or to simply replace the entire unit. A study into the finance, using empirical calculations and case studies, revealed that due to time spent implementing the components into the hub and the maintenance reduction that would be expected from a new modern turbine, replacing the entire turbine is more economical. Project costs were estimated to be approximately £1,210,000, with yearly maintenance costs being approximately £14,500. While this may vary in application, the constraints of this project pointed towards this methodology of determining costs for the purposes of this project - a sensitivity analysis, however, allowed the cost implications to be evaluated.

As the yearly average daily running hours of the site are hard to quantify due to it being dependant on rainfall/ reservoir levels, average daily flow rates/ power output was unable to be obtained. It was known however that the plant could run at 5.37 hours at full load, although this full load may actually represent an operating time of say 6 hours or more, with an afternoon peak at full load. Consequently, an investigation into the required time spent not at the rated flow that would make the project economical was undertaken - in respect to changing estimated annual average daily operational times. Results showed for the project to be economically feasible the average daily running hours had to be a minimum of 7 hours or above and that the ‘afternoon peak’ at rated flow could not surpass 55% of the total operational time. The maximum 55% time at rated flow, though is dependent on the remaining time being held at 60% rated flow in order for the difference in efficiency from the newly installed turbine to make a profit - that would achieve payback. This may be representative in the scenario that the flow is held at this speed in order for Carsfad pool to fill back up in preparation for a peak load. In which retrofitting of the Kaplan turbine, in this case, would mean that more power can be outputted as the pool between Kendoon and Carsfad refills. A full Kaplan turbine could also be beneficial in allowing the pool to refill faster by allowing the flow to drop in order to refill, while not being as financial punished by the massive drop in efficiency. In a wider perspective as more and more, stochastic renewables enter the network, faster refilling of the pool would increase the availability of the plant, allowing it to meet the sudden drop in power that can occur in stochastic renewables. Counterintuitively as the operational time increased in the sensitivity analysis then time spent at rated flow decreases, as more time is required at lower flow rates to meet the 32.2MW known yearly average daily output. Contingency costs were found not have an effect on determining the flow rate required, and instead fixated on the PV costs/ PV benefits, which reduced at an average rate of 5% between the changes in contingency rate.

Numerical methods similar to that used for the Kaplan turbine were attempted for the Francis turbine to determine if a change in blade angles to those found in literature could boost the efficiency of the turbine. However, it was revealed that the accuracy of the losses required for this analysis is not obtainable through this method. Instead, (Gordon, 2001) empirical method was used, calibrating to the known existing efficiency curves, to produce efficiency and power curves against changing flow rates. This resulted in an expected efficiency increase of 5.04%. which align with that projected by GE and found in the Kansai case study. A conducted CBA found project costs to be approximately £2,418,000, which reflected that found in the case study. Yet, at the projected costs, the CBA revealed that the project would not be feasible over a 30-year period. Due to uncertainty surrounding the true costings of such a project a sensitivity analysis was conducted. The analysis revealed that for the project to be feasible either a discount factor must be less than 2.5%, the project to cost less than 64% of that estimated, or for the site to run on a yearly operational time average of 19 hours per day, was required. Furthermore, it was found that the efficiency of the turbine would need to fall below 86% before a replacement should be considered due to the high upfront costs.

A further feasibility study based on literature was conducted and a method of reducing costs was found through the use of robots, which was being used in uprating projects in Canada. Results from a CBA on the solution revealed for the project to be feasible, based on a maximum 1.5% efficiency increase expressed by the author then component costs would need to be £163,000 or less. Although this may be difficult to achieve at this price, where a further investigation into the economic feasibility of investing in one of the machines, for retrofit modernisation of the turbines every 1.5% drop in efficiency, should be conducted.

While economic feasibility studies in this project focus in on single retrofits, if either of the turbines were to be replaced then it may be worthwhile to upgrade the generator and other associative components to make the project more feasible. This would allow the downtime to be maximised for as high of an increase in efficiency/output as possible in return. Moreover, this project did not investigate the possible finance from subsidies that could be obtained if refurbishment through retrofit was to take place. Similarly, to that achieved from the ROC subsidy. The project did also not investigate whether it is preferable for the utility company to have increased output or increased efficiency from the retrofit. This would rely on a study of the predicted penetration of renewables into the network and an understanding of the role hydro should play in the energy transition in Scotland. The change of climate that has been seen with the 30% increase in rainfall at the GHES over the past 25 years, will also play a role in this decision. Moreover, the increase in rainfall may also open up scope to increase the head of the plant, or widen the penstock, which could result in a larger turbine; as mentioned in 3.3 - Uprating of the Turbine, by (Gordon, 2001), larger diameters increase the efficiency and the output of the turbine.

Overall, the workings of this report have given an initial appraisal of potential retrofit solutions for the GHES. Time constraints of the project have limited the level of detail of the solutions, where future work is required to complete the feasibility study. A single visit to the site realised some potential solutions, however, as stated by (Gummer, 1993) in order to fully assess the uprating potential through retrofit, a detailed study based on the condition of the components much be achieved.

Section VI - Conclusion

In the investigation for retrofit solutions for the Galloway Hydros that increase their output or efficiency, an extensive literature review was conducted. This revealed, and supplied, the individual areas and components that are apparent in the Galloway Hydro-Electric scheme that could be subject to an efficiency or output enhancement found in literature - backed up by successful case studies. In conclusion, the literature review revealed retrofit solutions were found to be typically equipment based, specifically in regard to components surrounding the turbine and the generator. Major efficiency and output improvements of these components were found to be modernising of the turbine runner, which could lead to efficiency improvements as much as 5% and rewinding of the generator in conjunction with improved insulation, where output improvements were found as much as 15%.

A site visit was conducted to test the viability of the solutions found in the literature review. Potential scope was found for the Francis turbines on site that had not been modernised over the course of the scheme's lifetime as well as the potential for a variable pitch Kaplan turbine at either the Carsfad, Drumjohn or Earlstoun HPPs. Accordingly, these select solutions were taken forward for technical analysis and for a practical and economic feasibility review.

The technical analysis provided estimated efficiency curves for Carsfad, that revealed that installation of a variable pitch Kaplan turbine could maintain peak efficiency in the majority of flow rates away from the rated flow. A practical retrofit feasibility study highlighted two methods of retrofit for the solution, to which a CBA concluded that replacing of the turbine would be the most economical solution. An economic study projected cost for the retrofit at £1,210,000, with yearly maintenance costs being approximately £14,500, based off of empirical formula and case studies. A further CBA revealed that in order for the project to be feasible at this cost, then the rated flow must be available at a maximum of 55% of the time at an average daily operating time across the year of 7 hours or above.

Using a method derived from case studies, projected efficiency curves were determined for modernisation of the Francis turbine at Glenlee, revealing efficiency improvements as much as 5.04% could be achieved at rated flow. Deriving from literature and empirical formula the project was valued at £2,418,000, where maintenance costs are expected to drop by 2.5% due to the modern replacement. In turn, a CBA revealed that the project would not be financially feasible over a 30-year period, at the projected costs. A set of sensitivity analysis revealed that for the project to be feasible either a discount factor must be less than 2.5%, the project to cost less than £1,100,000, or for the site must run on a minimum yearly average daily operational time of 19 hours per day. A further feasibility study revealed that the use of a six-axis robot could make the modernisation retrofit project feasible, although component costs must be less than £163,000 to achieve payback over a 30-year period.

The workings of this project should provide Scottish Power support in future decisions in regard to retrofits at the Galloway Hydros - that have the aim of improving the efficiency or output of the plant. On a wider scope, this project has provided empirical calculations, potential solutions, and methodology that are valuable to HPPs considering uprating, allowing them to stay competitive as the energy transition to more sustainable energy resources continues.

Section VII - Future Work

Subject to a site visit to GHES, potential solutions in regard to efficiency and output improvements were found, however due to the time constraints of this project only two were taken through thoroughly. In this section a look towards other potential solutions found that were not seen through will be discussed in relation to future work. Additionally, future work associated to the proposed solutions in this project, which have risen from the analysis, will be discussed.

Following the site visit it was found that the stators installed at HPPs on the GHES have never been rewound. As found in the literature review, replacing the stator with modern windings and thinner insulation will allow the capability to insert more copper windings into the stator, and in the words of Andritz hydro have the capability to improve the output by between 5-10% (Andritz Hydro, 2012). As seen in the renovating of the SSE owned power plant where output improved as much as 15% (Barbier, 2017). With this evidence and that in the literature review, it is clear that an investigation into rewinding the stator must take place. As part of this project, data was gathered in respect to generator rewinding and a further literature review on the topic was completed in preparation for the study. However, due to time constraints of the project, and a lack of uncertainty surrounding the calculations, the section was not completed. Nevertheless, an information pack including gathered information required for generator rewinding in accordance to IEEE standards and further information supporting the solution, enabling future work, can be found in Appendix I (IEEE Power & Energy Society, 2010).

A similar situation was found in respect to the thrust bearings where a potential solution was found, yet due to time constraints and contradicting papers around the true value of an efficiency improvement for the solution prompted the section to be redacted. The current thrust bearings installed on the GHES, are that of the original design and have undergone little modifications or refurbishment since instalment. As mentioned in Section 2.2 (pg. 22) a soft alloy coats the pads of the bearings, while traditionally Babbitt, a more recent technology has seen a shift away from this conventional material towards a more polymer-based material. The drive towards polymer-based materials is fuelled by their capabilities to operate in higher temperatures, reduced coefficient of friction and flexible to both thermal movement and fitting (Ettles *et al.*, 2003). Across the case studies explored, coating the thrust bearings pads with polymer-based material have seen to be a key consideration when determining uprating the plant. Recent studies have shown a power loss reduction of up to 8%, as well as the capabilities to operate at higher temperatures, allowing the possibility to increase the load capacity (Glavatskih, 2003). If rewinding of the generator is considered for uprating, then the thrust bearing should be a strong consideration to be completed in conjunction. Once more an information pack enabling future work and backing the feasibility of the solution can be found in Appendix J.

Improving of the ventilation system was also proposed by expertise on site, which was found in Section 3.2 could enable higher capacity by up to 30% through enabling the stator temperature to remain at the desired temperature at increased loads (Moore, 2000; BCK Mishra, 2015). Without a change in copper however this solution was found to only increase the efficiency by a maximum of 0.3% (Goldberg and Lier, 2011; Mesa Associates Inc. and Oak Ridge National Laboratory, 2011a). This leads to suggest, similarly to the thrust bearing, that if the generator was to be rewound then an enhancement to the ventilation system should be considered in conjunction to the uprate.

Workings of this project have focused in on more immediate potential solutions, where the onset of climate change and recent studies revealing an increase in rainfall on the site could open up the opportunity for future work to be completed in this context. One potential solution in respect to this could be the improving of the output of GHES through compensation flow recovery, which would increase as the capacity of the reservoirs increase. While this was not taken further due to an already internal investigation already been completed on the solution, backing of this solution can be found in Section 3.2, where similar case studies of the solution were found and discussed. Likewise, the increase in rainfall could lead to economic feasibility of construction of an additional reservoir. During the design phase of the project, several additional reservoirs were proposed for the scheme, although were not seen through to commission due to the costs associated at the time. Additional reservoirs will aid the reduction of flooding, which during winter could mean that both turbines could run, instead of one being turbined off in order to control the flood. Possible locations of the reservoirs include the water of Ken or in the water of Deugh; these locations of these reservoirs would also benefit the rest of the scheme due to it being located above Kendoon.

Figure 39: Previously Proposed Extra Reservoir Locations

A further solution which was proposed by expertise on site, which were not covered in the literature review and are specific to the site, is energy recovery for starting of the auxiliary services. This would require a refurbishment of the micro-hydro which is currently redundant at Tongland, or installing such a system in other plants, to enable to power recovery for operating of the auxiliary services. The existing redundant micro-hydro at Tongland can be seen in Figure 41.

Figure 40: Possible Refurbishment to a Redundant Micro-Hydro at Tongland

In respect to the solutions proposed within Section IV, future work should include a CFD investigation based on the gathered information and the knowledge base built up for both topics. By undertaking data gathering on the power outputs, or daily flow rates, for all sites will enable deeper understanding that will allow more accurate efficiency and power curves for the proposed sites to be established - resulting in increased accuracy of the performance benefits. CFD analysis should also investigate each of the potential impacts and considerations mentioned in Sections 4.1.5 & 5.1.6, to further establish the feasibility of each of the solutions. Manufacturers and engineering consultants should be contacting for more accurate costings for each of the projects.

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List of Appendices

APPENDIX A - Appendix Nomenclature

b_2	Guide Vane Blade Height	m
Q	Flow Rate	m^3/s
r_2	Guide Vane Radius	m
t_2	Blockage	m
V_{2x}	Radial Guide Vane Velocity	m/s
r_3	Runner Blade Radius [2]	m
$V_{3\theta}$	Tangential Runner Blade Inlet Velocity	m/s
α_3	Inlet Runner Blade Angle	°
α_2	Guide Vane Angle	°
V_{3x}	Radial Runner Blade Velocity	m/s
b_3	Runner Blade Height	m
$V_{2\theta}$	Tangential Guide Vane Exit Velocity	m/s
V_3	Inlet Runner Blade Velocity	m/s
V_2	Guide Vane Exit Velocity	m/s
$W_{3\theta}$	Relative Inlet Runner Blade Velocity	m/s
U_3	Runner Blade Speed	m/s
N	Rotational Speed	rpm
$W_{4\theta}$	Tangential Runner Blade Exit Velocity	m/s
V_4	Runner Blade Exit Velocity	m/s
W_4	Relative Runner Blade Exit Velocity	m/s
W_{4x}	Radial Runner Blade Exit Velocity	m/s
V_5	Draft Tube Velocity	m/s
$\dot{m}$	Mass flow rate	kg/s
ω	Angular Velocity	rad/s
P	Turbine Power Output	W
k	Friction Coefficient	-
ΔH_{gv}	Guide Vane Dynamic Head	m
ΔH_r	Runner Dynamic Head	m
ΔH_b	Bend Dynamic Head	m

ΔH_{ideal}	Ideal Total Head Drop	m
η	Efficiency	%
g	Gravity	m/s^2

APPENDIX B – Original Performance Curves

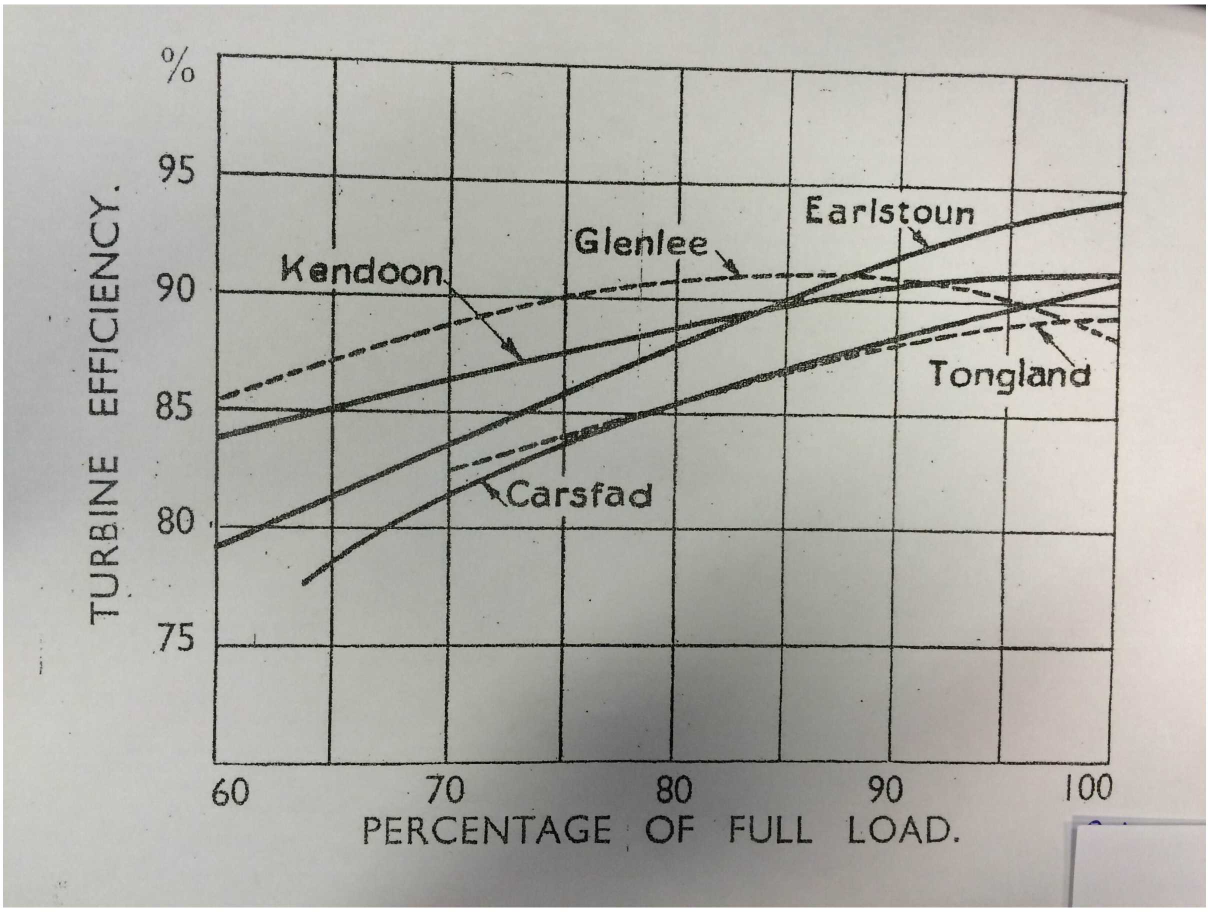


Figure 41: Original Performance Curves of GHES

APPENDIX C - Carsfad Collected and Estimated Site Data.

Estimates/Calculated in bold.

Table 10: Carsfad Obtained & Estimated Data

Symbol	Inputs	Parameter	Unit
θ	Guide Vane Angle	**16.89**	°
n	RPM =	214.41	rpm
Q	Volumetric Flow Rate	37	m3/s
r2	Runner Radius 1 =	1.37	m
Da	Inlet Diameter	2.74	m
DN	Outlet Diameter	1.23	m
r3	Outlet Radius	0.615	
ρ	Density	998	kg.m^3
H	Head	20	m
Bo	Wicket Gate Height at the inlet	0.8	m
Lg	Guide Vane Length	**1.6**	m
B1	Runner Blade Height	0.8	m
Rd	Draft Tube Radius	1.4	m
t	Blockage	**0.057**	m
b3		0.6	m
V5	Draft Tube Velocity	**3.615**	m/s
K_{GV}	Guide Vane Loss Coefficient	**0.005**	-
K_{Bend}	Bend Loss Coefficient	**0.005**	-
K_{Runner}	Runner Loss Coefficient	**0.006**	-
K_{Draft}	Draft Loss Coefficient	**0.02**	-

APPENDIX D - Kaplan turbine Performance Enhancement Methodology

Due to it being difficult to determine the accuracy of the blade angle, the following method was used. Kaplan turbine runner design methodology was used from the paper by (Chaichian, Perez Rojas and Tureanu, 2014), due to the parameter similarities in the exercise to the case study, allowing validation, and for the level of comprehension. Equations were manipulated to allow the angles to be fixed and for the guide vane angle to update at varying flow rates. Parameters used in the equations can be seen in Appendix C.

Equation 16

$$V_{3x} = \frac{Q}{2\pi b_3 r_3}$$

Equation 17

$$V_{3\theta} = \tan(\alpha_3)\, V_{3x}$$

Equation 18

$$V_3 = \sqrt{{V_{3\theta}}^2 + {V_{3x}}^2}$$

Equation 19

$$V_{2\theta} = \frac{r_3 V_{3\theta}}{r_2}$$

Equation 20

$$V_{2x} = \frac{Q}{2\pi b_2 r_2}$$

Equation 21

$$V_2 = \sqrt{{V_{2\theta}}^2 + {V_{2x}}^2}$$

Equation 22

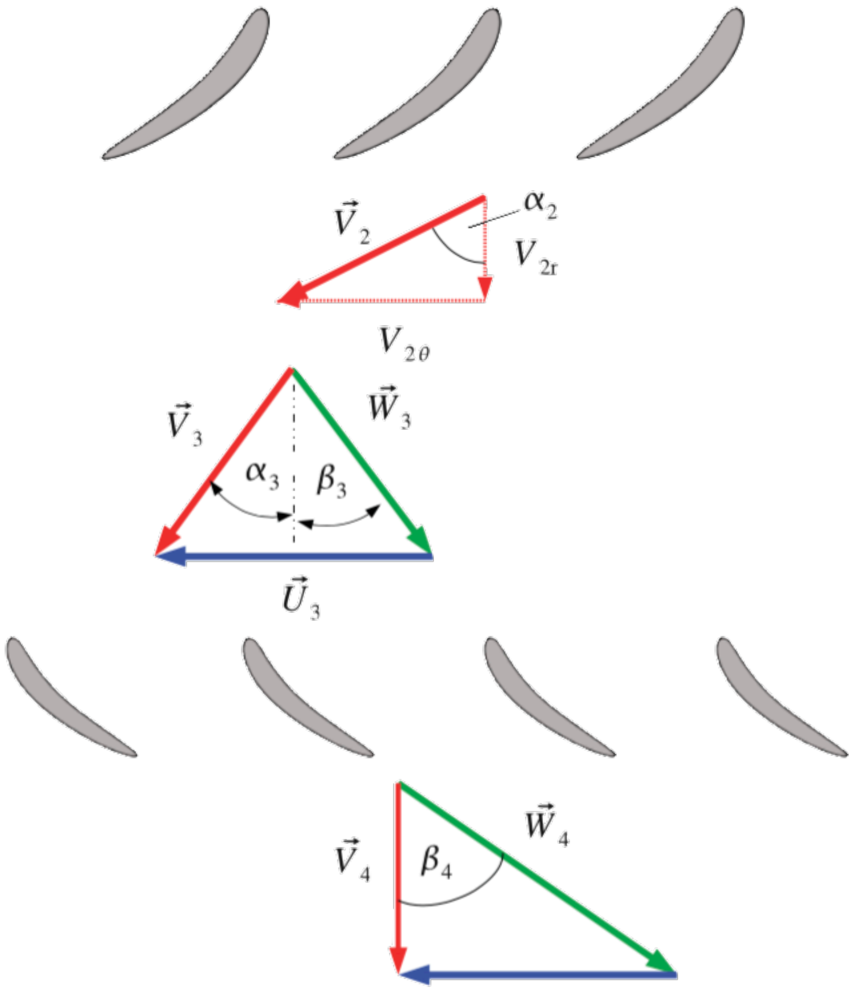
$$\alpha_2 = \tan^{-1}\left(\frac{V_{2\theta}}{V_{2x}}\right)$$

Euler’s equation states that:

Equation 23

$$P = \dot{m}\omega(R_3 V_{3\theta} - R_4 V_{4\theta})$$

Where $V_{4\theta} = 0$ since exit velocity from the runner is assumed to be purely radial.



Turbine efficiency is therefore determined using the equation;

Equation 24

$$\eta = \frac{P}{\dot{m}\, g\, H_{drop}}$$

H_{drop} is taken as the sum of the ideal head drop for the power calculated and the dynamic losses. Where the ideal head drop ΔH_{ideal} is defined from the following equation:

Equation 25

$$\Delta H_{ideal} = \frac{P}{\dot{m}\, g}$$

Dynamic losses can be calculated from the following equations which factors in the main speed and the friction coefficient to give a rough estimation of the losses through the turbine.

Equation 26

$$W_{3\theta} = tan(\beta_3)\, V_{3x}$$

Equation 27

$$W_{4x} = W_{3\theta}$$

Equation 28

$$U_3 = \frac{2\pi N}{60} r_3$$

Equation 29

$$W_{4\theta} = -U_3$$

Equation 30

$$W_4 = \sqrt{{W_{4x}}^2 + {W_{4\theta}}^2}$$

Equation 31

$$\Delta H_r = k\frac{{W_4}^2}{2g}$$

Equation 32

$$\Delta H_{gv} = k\frac{{V_2}^2}{2g}$$

Equation 33

$$\Delta H_{dt} = k\frac{{V_4}^2 - {V_5}^2}{2g}$$

Equation 34

$$\Delta H_b = k\frac{{V_3}^2}{2g}$$

Utilising the method stated, the Figure 27 was revealed through the changing of the flow rate at a fixed angle.

APPENDIX E - Kaplan turbine Performance Enhancement Methodology

Table 11: Minimum Payback CBA for Maximum Flow Rate at Rated Constraint to the Average Daily Output

Average Daily Operating Hours			7 hours			8 hours			9 hours		
Contingency Rate			**-25%**	**-15%**	**-5%**	**-25%**	**-15%**	**-5%**	**-25%**	**-15%**	**-5%**
% of rated flow rate	1	Time Spent at Flow Rate	3.88	3.88	3.88	3.21	3.21	3.21	2.52	2.52	2.52
	0.95		0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.9		0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.85		0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.8		0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.75		0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.7		0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.65		0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.6		2.45	2.45	2.45	4.09	4.09	4.09	5.78	5.78	5.78
Costs/ Benefits			**0.65**	**0.74**	**0.77**	**0.44**	**0.48**	**0.52**	**0.33**	**0.36**	**0.39**

Table 12: Maximum Flow Rate Possible to Achieve Payback

Average Daily Operating Hours		7 hours			8 hours			9 hours		
Contingency Rate		**25%**	**15%**	**5%**	**25%**	**15%**	**5%**	**25%**	**15%**	**5%**
Percentage of rated flow rate	1	4.10	4.30	4.50	5.10	5.30	5.50	6.10	6.30	6.54
	0.95	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.9	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.85	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.8	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.75	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.7	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.65	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.6	2.20	1.97	1.76	2.20	1.97	1.76	2.20	1.97	1.76
Average Daily Output		**33**	**33**	**34**	**39**	**39**	**40**	**45**	**45.5**	**46.5**
Negative Contingency Rate		**-25%**	**-15%**	**-5%**	**-25%**	**-15%**	**-5%**	**-25%**	**-15%**	**-5%**
Percentage of rated flow rate	1	5.10	4.80	4.72	6.05	5.76	5.66	7.00	6.80	6.80
	0.95	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.9	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.85	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.8	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.75	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.7	0.10	0.40	0.10	0.10	0.40	0.10	0.10	0.41	0.10
	0.65	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	0.6	1.32	1.20	1.58	1.32	1.19	1.58	1.30	1.19	1.58
Average Daily Output		**36.7**	**35.7**	**35**	**42.5**	**41.5**	**40.78**	**48.1**	**47.7**	**47.57**

APPENDIX F - Glenlee Collected and Estimated Site Data.

Estimated in bold.

Table 13: Gathered &. Estimated Glenlee Data

Symbol	Inputs	Parameter	Unit
θ	Guide Vane Angle	**60.91**	°
β_2	Runner Inlet Angle	**62.18**	°
β_3	Runner Outlet Angle	**25.52**	°
n	RPM =	430.7	rpm
Q	Volumetric Flow Rate	14.5	m3/s
r2	Runner Inlet Radius	0.734	m
r3	Runner Outlet Radius	0.6875	
ρ	Density	998	kg.m^3
H	Head	89.56	m
B1	Wicket Gate Height at the inlet	0.228	m
B2/3	Runner Blade Height	0.8	m
P	Nominal Output	12	MW

APPENDIX G - Francis Turbine Turbomachinery Calculations

The following equations were taken from (Dixon and Hall, 2010), the book was chosen as it was found to be well referenced when conducting the literature review and well established; now in its 4th edition. The approach taken for estimating the power output began by determining the guide vane angle and the inlet and outlet angles of the runner. This was achieved using the known power outputs and corresponding efficiency from the recorded data during 2007 testing, working back through equations 45,42, 40 and 41. The known rpm speed was used for rated speed and a generator efficiency of 97% was assumed. The formulae were then re-arranged to that seen in equations 37 to 47 and solved for the power output. Calculated inlet and outlet runner angles, as seen in Table 13, were then inputted as fixed values, with the guide vane angle updating using equation 46. The set of equations were then copied for each 5% incremental change in flow rate, where goal seek was used using the characteristics of the known power curve to determine the actual rpm per flow rate. It was found that unit speed was constant for the majority of the flow rates, verifying the guide vane angle once more. Efficiencies were all linked back to a single column allowing updating of the efficiency to be done at once. Once Gordons equation produced the calibrated efficiencies against flow rate, they were then copied into the efficiency column, updated the efficiency of the turbine at each incremental flow rate. A link to all the actual power outputs, after multiplying by the calculated turbine efficiency, provided the new power output.

Equation 35

$$U_3 = \tan(\beta_3)$$

Equation 36

$$U_2 = \frac{2\pi N}{60} r_2$$

Equation 37

$$V_{3x} = \frac{Q}{2\pi b_3 r_3}$$

Equation 38

$$V_{2x} = \frac{Q}{2\pi b_2 r_2}$$

Equation 39

$$V_{3\theta} = 0$$

Equation 40

$$V_{2\theta} = U_2 - \frac{V_{2x}}{\tan(\beta_2)}$$

Equation 41

$$V_2 = \sqrt{V_{2\theta}{}^2 + V_{2x}{}^2}$$

Equation 42

$$V_3 = \sqrt{V_{3\theta}{}^2 + V_{3x}{}^2}$$

Euler's equation states that:

Equation 43

$$P = \dot{m}\omega(R_2 V_{2\theta} - R_3 V_{3\theta})$$

Guide Vane Updating Angle Equation

Equation 44

$$\alpha_1 = \tan^{-1}\left(\frac{V_{1\theta}}{V_{1x}}\right)$$

Equation 45

$$\eta = \frac{P}{\dot{m}\, g\, H_{drop}}$$

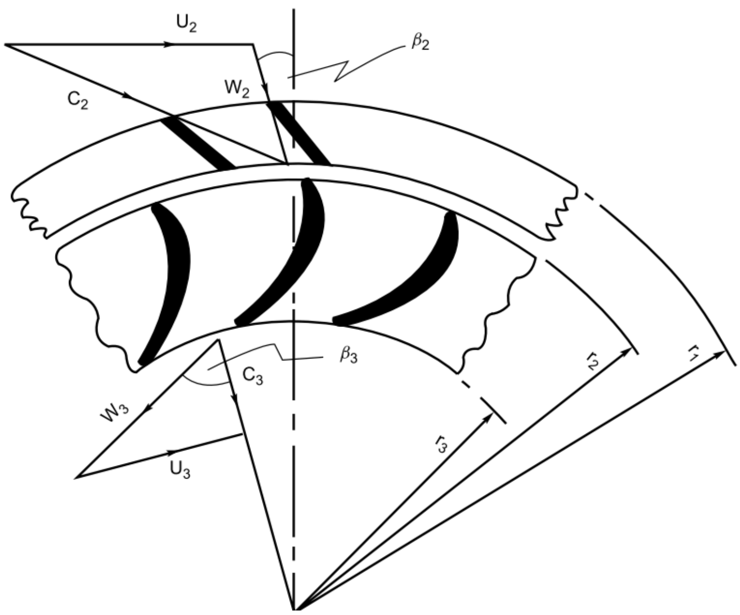


Figure 42: Francis Turbine Runner Velocity Triangles (Dixon and Hall, 2010)

APPENDIX H - Francis Turbine Cost Estimate

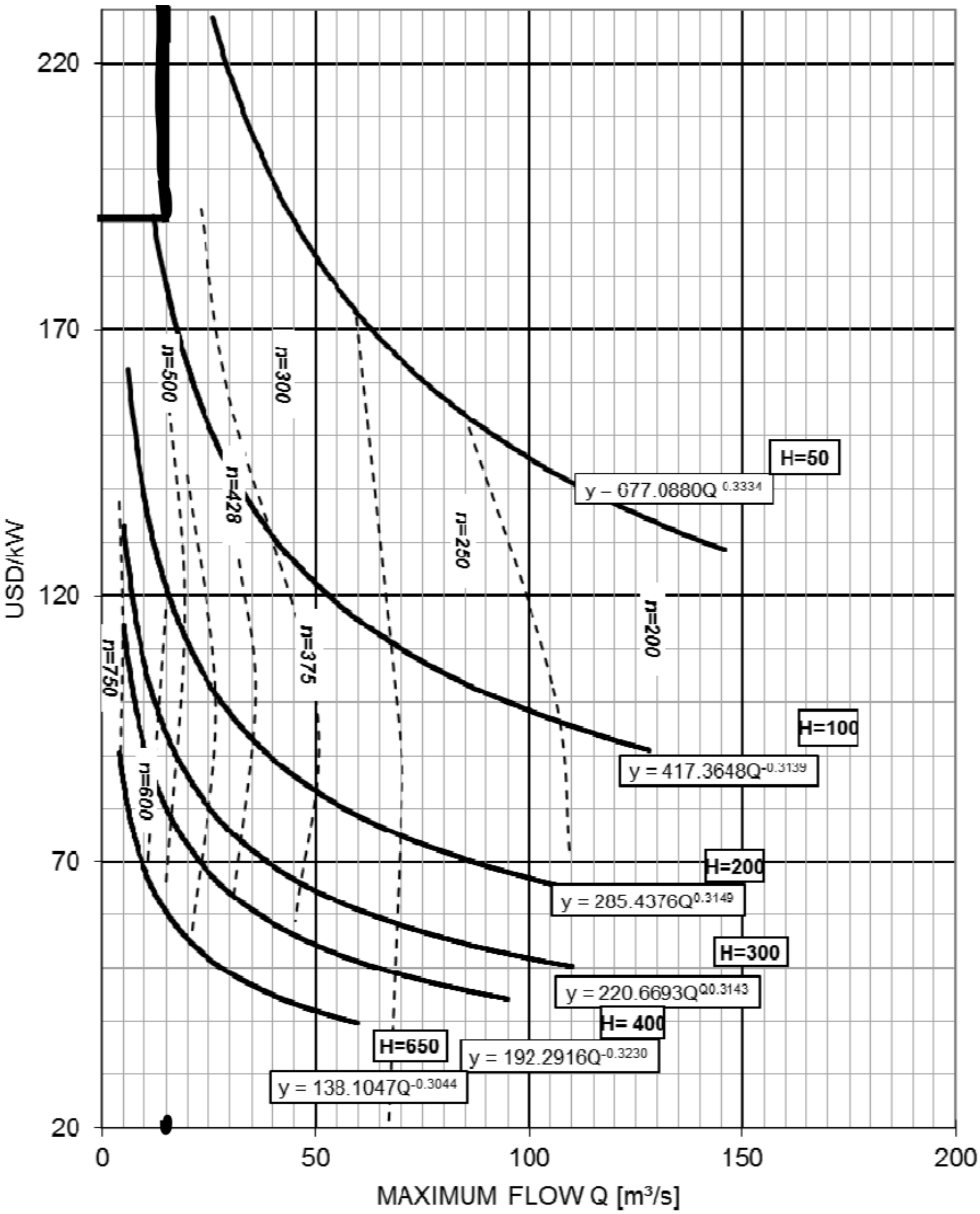


Figure 43: Francis Turbine Cost Estimate (SWECO Norge AS, 2012)

APPENDIX I – Generator Rewinding

Table 14:Required Rewinding Data in Accordance to IEEE

	PARAMETER	VALUE	UNIT	COMMENTS
General Machine				
	Insulation Class	Class B		Stator winding is bitumen resin based
	Insulation Thickness	4.19	mm	Including turn tape and coronashield
	Does it contain asbestos?	Yes		Rotor pole coils and stator coil coronashield
	Operational temperatures in the winding			Machines were commissioned in the 1930's. No information available.
	Temperature rise at various loads			Machines were commissioned in the 1930's. No information available.
	Power Factor	0.8		
	Maximum continuous rating	7500	kVA	
	Terminal voltage	11	kVA	
	Current	394	A	
	Phases	3		
	Frequency	50	Hz	
	Number of poles	28		
	Speed	214	rev/min	
	Orientation – vertical or horizontal	Vertical		
	Direction of rotation	Clockwise		Viewed from above
Stator				
	Continuous pile	No		
	Continuous pile, 2 section, 4 section	2	Section	
	Bore diameter	4191	mm	
	Gross length	457.2	mm	
	Air ducts (# of ducts, and dimension)	8 off 9.53	mm	
	Core packets (# of packets, and dimension)	9 off 42.33	Packets	Average value. Some difference between packet lengths
	Number of slots	264		
	Skew in core	None		
	Slot width	17.2	mm	Punched slot
	Slot wedge width	21.6	mm	
	Total slot depth	130.3	mm	Punched slot
	Total coil depth	123.3	mm	Including 2.54 mm separator
	Slot pitch	49.87	mm	At bore
Winding Configuration				
	Lap or wave	Lap		
	Number of coils	264		
	Turns/coil	3		
	Throw	1 to 9		
	Coils pitch	As above		
	Coil grouping	3 3 3 3 4 3 3		
	Connection	Series Star		All coils in series per phase

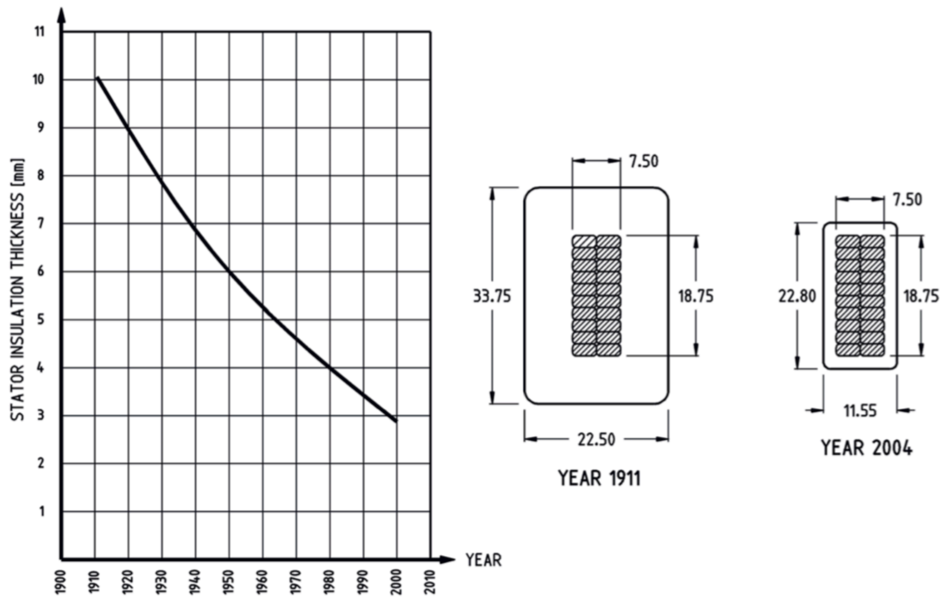


Figure 44:Decrease in Insulation Thickness Over the Last Decade (Znidarich, 2013)

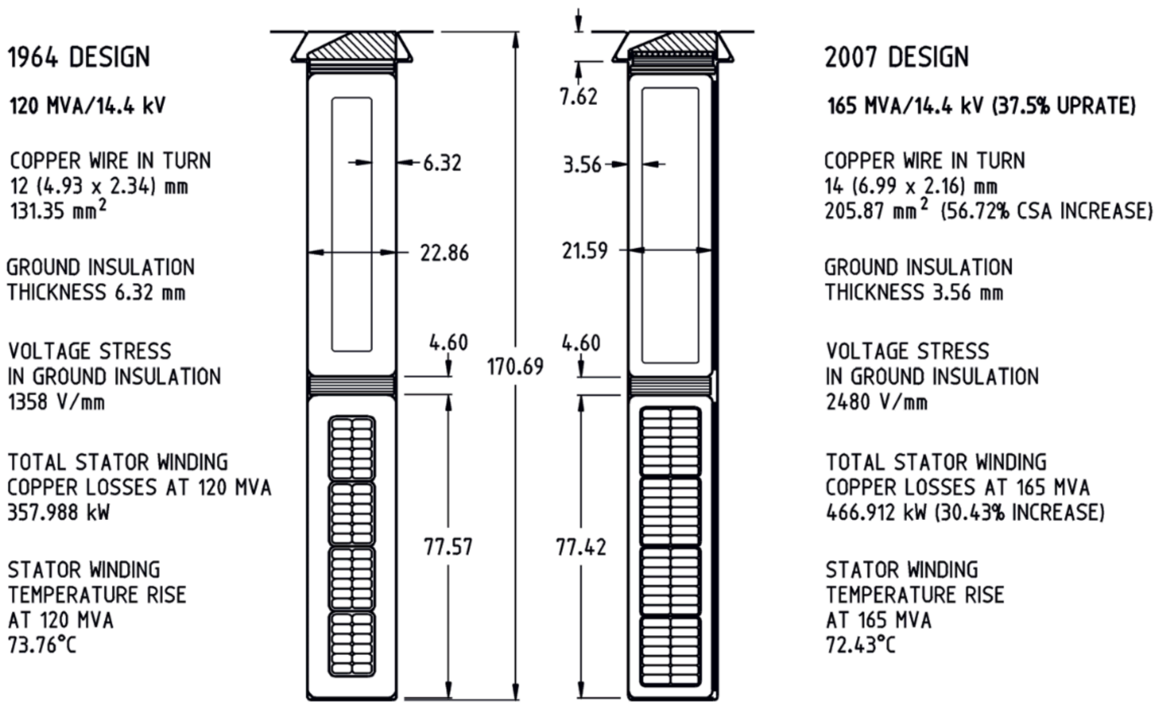


Figure 45: Comparison Between Old and New Technologies

Recommended Reading:

Farell, C. and Gulliver, J. (1987) 'Hydromechanics of Variable Speed Turbines', Journal of Energy Engineering, 113(1), pp. 1–13. doi: 10.1061/(ASCE)0733-9402(1987)113:1(1).

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Lyles, J. F. (1971) 'Procedure and Experience with Thermoset Stator Rewinds of Hydraulic Generators'.

Moore, W. G. (1999) 'Mechanical considerations for uprate and rehabilitation of hydro-generators', IEEE International Electric Machines and Drives Conference, IEMDC 1999 - Proceedings, pp. 824–826. doi: 10.1109/IEMDC.1999.769254.

Stone et al. (2004a) 'Evaluating Insulation Materials and Systems', ISBN 0-471-44506-1 © 2004 Institute of Electrical and Electronics Engineers, pp. 47–81.

Stone et al. (2004b) 'Stator Winding Insulation Systems in Current Use', ISBN 0-471-44506-1 © 2004 Institute of Electrical and Electronics Engineers, pp. 95–111.

Stone et al. (2014a) 'General Principles of Winding Failure, Repair and Rewinding', Electrical Insulation for Rotating Machines, pp. 159–170. doi: 10.1002/9781118886663.ch7.

Stone et al. (2014b) 'Historical Development of Insulation Materials and Systems', Electrical Insulation for Rotating Machines, pp. 83–110. doi: 10.1002/9781118886663.ch3.

Stone et al. (2015) Rotating Machine Insulation Testing, ISBN 0-471-44506-1 © 2004 Institute of Electrical and Electronics Engineers. Available at: http://www.livehv.com.au/rotating-machine-testing/.

APPENDIX J – Thrust Bearings

Removal of the bearings should be relatively straight forward and involves removal of the thrust housing, by removing of the guide pins and housing bolts, followed by the unbolting of the two sections of the thrust bearing, in some cases the shoes can be removed individually. Due to the properties of PTFE one of the main challenges to making this solution is feasible is determining a method of adhering the material to steel surface of the bearing. To date the most successful method of bonding, established back in 1960's in Russia, consists of forcing the PTFE into the gaps of wire meshing through the applying of high pressure, the wire mesh is then soldered to the steel face (Glavatskih, Wasilczuk and Fillon, 2004). The wire mesh has the advantage in that it allows the PTFE to expand when under loading and should be made of a soft steel similar to that of Babbitt, in case the rare occasion the PTFE fails, the mesh can act similar, but not as effective, as Babbitt.

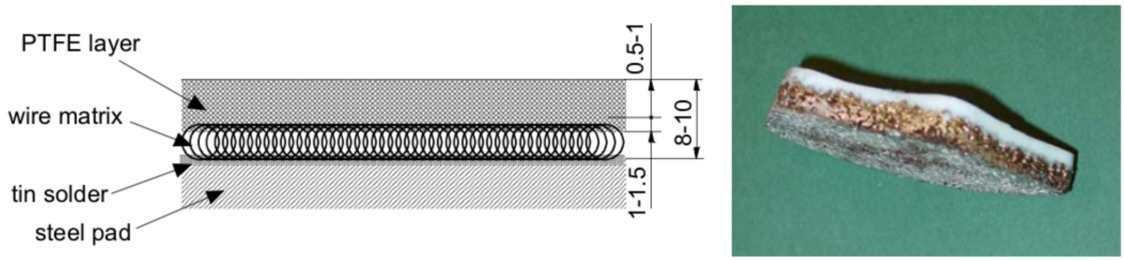

Figure 46:Method for Applying PTFE to Thrust Bearings *(Glavatskih, Wasilczuk and Fillon, 2004)*

Another method developed in Slovakia, involves bolting the polymer-based material to the steal pad through a steel pad cover along the edge of the pad (Glavatskih, Wasilczuk and Fillon, 2004). This method is more robust than that of the wire-mesh method and has been implemented across 9 HPP plants in Slovakia.

If the thrust bearing upgrade is undertaken in parallel with a runner replacement or instalment of a new turbine, then considerations must be made in terms of the increased load and temperatures that can arise from the recent instalment on the thrust bearing. This was a significant problem at the Akosombo plant in which the thrust bearings failed on 20 months after the instalment of the new runner (Thrust *et al.*, 1965). The new design of the thrust bearing must also consider the possibility of cavitation, that could occur from a sudden pressure drop, resulting from poor design. Cavitation in this case normally occurs close to the high-pressure oil lift and new designs must be carefully checked in order to prevent any such case (Beck, 2016). A method of solving this is to correctly manufacture the new segmented runner plate and bolt and key the two halves of the ring, to prevent any spaces that would allow oil pressure to vacate (Beck, 2016).

Evidence has shown that a polymer-based pad coating works best at an offset of 5 to 7 % pivot point, in comparison to babbitted bearing which works best at 15 to 25% pivot point (Beck, 2016). Design considerations should be made when redesigning the thrust pads in relevance to the possibility of thrust runner contact. Runner contact occurs when upgrading the thrust bearing pads, considerations must be made to ensure that the plate is free of any grooves that would allow a uniform film of oil, this could be done by simply machining down the plate to remove any grooves (Beck, 2016).

PTFE specific, while the new design can achieve increased loading, care must be paid attention to the potential of role concavity on the PTFE facing, resulting from the oil film pressure, where in the circumferential direction can cause potential impacts on the crown (Liming *et al.*, 2017).

Recommended Reading:

Ettles, C. M. et al. (2003) 'Test Results for PTFE-Faced Thrust Pads, With Direct Comparison Against Babbitt-Faced Pads and Correlation With Analysis', Journal of Tribology, 125(4), p. 814. doi: 10.1115/1.1576427.

Farell, C. and Gulliver, J. (1987) 'Hydromechanics of Variable Speed Turbines', Journal of Energy Engineering, 113(1), pp. 1–13. doi: 10.1061/(ASCE)0733-9402(1987)113:1(1).

Glavatskih, S. B. (2003) 'Evaluating Thermal Performance of a PTFE-Faced Tilting Pad Thrust Bearing', Journal of Tribology, 125(2), p. 319. doi: 10.1115/1.1506329.

Glavatskih, S. B. and Fillon, M. (2006) 'TEHD Analysis of Thrust Bearings With PTFE-Faced Pads', Journal of Tribology, 128(1),

Institut, M. F., Glavatskih, S. and Kuznetsov, E. (2010) 'The effect of PTFE Lining on Plain Journal Bearing Characteristics'.

LSimmons, J. E., Knox, R. and Moss, W. (1998) 'The Development of PTFE Faced Hydrodynamic Thrust Bearings for Hydrogenerator Applications in the United Kingdom', Proc Instn Mech Engrs Vol 212 Part J.

Mahieux, C. a. (2005) 'Experimental Characterization of the Influence of Coating Materials on the Hydrodynamic Behavior of Thrust Bearings: A Comparison of Babbitt, PTFE,

Piotr Pajaczkowski et al. (2015) 'Itaipu Binacional Hydro Power Plant Thrust Bearing Design Optimization for Higher Efficiency', Journal of Mechanics Engineering and Automation,

Experimental Results Highlighting Performance Differences Between PTFE & Babbitt Coated Thrust Bearings.

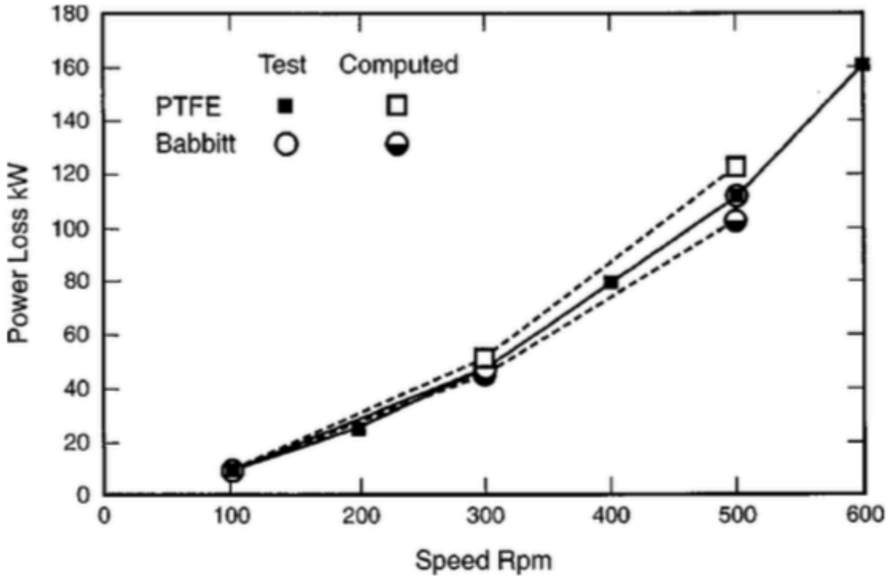

Figure 47: Measured and Test Comparison Between PTFE & Babbitt at 5MPa (Ettles *et al.*, 2003)

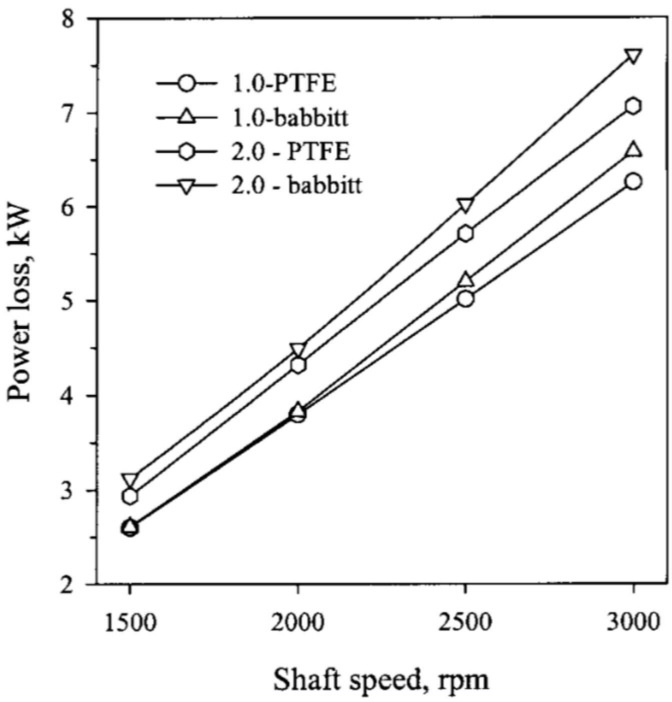

Figure 48: Power Loss Difference Between PTFE & Babbitt Coated Thrust Bearings at 1MPa and 2MPa (Glavatskih, 2003)