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Hydropower Retrofitting Feasibility study for a comparative Engineering and Economic Analysis: A case Study of Tendaho Dam

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Declaration

I, the undersigned, hereby declare that the work contained in this thesis is own original work and that I have not previously in its entirety or in part at any university for a degree.

Signature …………………………………………..

Approval Sheet

Hydropower Retrofitting Feasibility study for a comparative Engineering and Economic Analysis: A case Study of Tendaho Dam

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This is to certify that the thesis prepared by Abiy Sileshi Degfei entitled " Hydropower Retrofitting Feasibility study for a comparative Engineering and Economic Analysis: A case Study of Tendaho Dam.", is submitted for the approval of dissertation work for the fulfillment of MSc in Mechanical Engineering (Thermal Engineering).

It complies with the university's regulations and meets the accepted standards with respect to originality and quality.

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Abstract

This study assesses the technical and economic feasibility of retrofitting the Tendaho Dam in Ethiopia for hydropower generation while preserving its primary irrigation function. Three retrofit strategies are evaluated: the Dedicated Waterway Strategy (Option I), the Bifurcation Strategy (Option II), and the Channel Utilization Strategy (Option III). A sequential, quantitative, engineering-based methodology is applied, integrating hydrological analysis, engineering assessment, hydraulic modelling, and economic evaluation. Long-term hydrological data, including river discharge, reservoir levels, and irrigation releases, are analysed to determine dependable flows and available head. Structural and operational characteristics of the dam are assessed using original design documents and verified through field observations to identify physical constraints and ensure irrigation compliance. Technically feasible retrofit options are modelled using established hydropower equations to estimate installed capacity, power output, and annual energy generation. Economic and financial performance is evaluated using the RETScreen platform, employing indicators such as Net Present Value (NPV), Levelized Cost of Energy (LCOE), and payback period. The results demonstrate that retrofitting the Tendaho Dam is both technically and economically feasible. Options I and II achieve installed capacities exceeding 16 MW and annual energy generation greater than 111,000 MWh, confirming that the existing structural and hydraulic systems can support large-scale hydropower development without compromising irrigation requirements. Option III, although smaller in scale, remains technically viable and highlights the potential for incremental hydropower retrofitting. Financial analysis indicates that engineering design choices strongly influence economic outcomes. Option II yields the highest NPV, followed by Option I, while Option III generates only marginal returns. Cost-effectiveness analysis shows that Options I and II achieve LCOE values between 0.013 and 0.017 USD/kWh, well below the IRENA benchmark of 0.05 USD/kWh, whereas Option III, although feasible, is less competitive. The study concludes that optimized hydropower retrofitting of the Tendaho Dam offers a cost-effective and low-impact pathway for expanding renewable energy generation.

Keywords*: Hydropower Retrofitting, Economic Feasibility, Hydraulic Modelling, Net Present Value (NPV), Levelized Cost of Energy (LCOE)*

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Table of Content

Declaration ii

Approval Sheet iii

Abstract iv

Acknowledgement i

Table of Content ii

List of Tables vi

List of Figures viii

Abbreviations and Acronyms ix

CHAPTER ONE 1

INTRODUCTION 1

1.1 Background of the Study 1

1.2 Statement of the Problem 3

1.3 Objective of the Study 6

1.4 Research Questions 6

1.5 Significance of the Study 7

1.6 Scope of the Study 8

1.7 Limitations of the Study 9

1.8 Definition of Key Terms 10

1.9 Organization of the Thesis 12

CHAPTER TWO 13

REVIEW OF RELATED LITERATURE 13

2.1 Introduction 13

2.2 Theoretical Framework 13

2.3 Engineering Theoretical Background 16

2.3.1. Head and Net Head & Flow Duration Curve (FDC) 18

2.3.2 Efficiency of Hydro Turbine 19

2.3.3 Power and Energy Computation 20

2.4 Empirical Evidence 20

2.5 Previous Studies on Non-Powered Dam Retrofitting 23

2.5.1 European and North American Case Studies 23

2.5.2 African and Asian Case Studies 24

2.5.3 Ethiopian Dams Case Studies: Arjo Dedessa and Ribb Irrigation Dam 25

2.6 Conceptual Framework 26

CHAPTER THREE 29

METHODOLOGY 29

3.1 Introduction 29

3.2 Research Design 29

3.3 Study Site 30

3.4 Sources of Data 31

3.5 Data Collection 32

3.6 Data Collection Procedures/ Phases 33

3.7 Reliability and Validity of Data 34

3.8 Methods of Data Analysis 35

3.9 Ethical Considerations 36

CHAPTER FOUR 38

SALIENT FEATURES OF THE EXISTING TENDAHO HEADWORK STRUCTURES 38

4. 1 Introduction 38

4.2 Tendaho Dam Main Structure 38

4.3 Spillway 38

4.4 Dam and Reservoir Salient Features 39

4.5 Irrigation Outlet and Tunnel Conduit 39

4.6 Intake Structure 39

4.7 Outlet Flow Regulation 40

4.8 Main Canal 40

CHAPTER FIVE 42

HYDROLOGY 42

5.1. Introduction 42

5.2 10-Day Reservoir Simulation Model 42

5.3 Flow Duration of Curve 44

CHAPTER SIX 46

MODELING AND SELECTION OF SMALL-HYDRO COMPONENTS 46

6.1 Introduction 46

6.2 Flow Diversion Mechanism and Major Component Modelling 46

6.2.1. Option I: The Dedicated Waterway Strategy (Maximum Isolation) 46
6.2.2 Option II: The Bifurcation Strategy (Integrated Flow Management) 47
Operation Philosophy for irrigation and hydropower scenario for option I and II 49
6.2.3 Option III: The Channel Utilization Strategy 50
6.2.4 Option I: Diameter of the Penstock.. 51
6.2.5 Option II: Bifurcation of tunnel to the penstock Diameter 52
6.3 Losses and Net Head Calculation... 54
6.3.1 Option I: Head Loss 54
6.3.2 Option II: Head Loss 55
6.4 Hydropower Turbines Selection and Analysis.. 57
6.3.1. Number of Unit Determination 58
6.3.2. Determination of Power 60
6.3.3. Determination of Rotation Speed and Specific Speed 61
6.4 Energy Generation and Determination of Capacity Factor.................................... 65
6.4.1 Flow Constraint and Operational Efficiency 65
6.4.2 Technical Steps for Capacity Factor Determination 67
6.5 Determination of Turbine Parameters 72
6.5.1 Determination of the Diameter of Runner 72
6.5.2 Determination of the Dimensioning of Scroll case 74
6.5.3 Determination of the Dimensioning of Draft Tube.. 75
6.5.4 Dimensions of Power House.. 78
6.6. Quantification of Civil Works and Material Volumes 79
6.7. Powerhouse Civil Quantity Take-Off for Option I and II...................................... 79
6.8 Tailrace Channel Civil Quantity Take-off for Option I and II................................ 80
6.9. Estimation of Excavation at Dam Toe (abutment) for Powerhouse Footprint for Option I and II 80
CHAPTER SEVEN 82
PRELIMINARY FINANCIAL AND ECONOMIC ANALYSIS 82
7.1. Cost Derivation of Initial Investment.. 82
7.2 Determination of Civil Work Cost 82
7.2.1. Powerhouse Civil Works Cost Estimate 82
7.2.2 Tailrace Civil Works Cost Estimate.. 84
7.2.3 Tunnel Works Cost Estimate for option I 84

7.3 Determination of Electromechanical and Hydro Mechanical Cost for option I and II 85
7.3.1 Electromechanical Cost 85
7.3.2 Hydro Mechanical Cost 86
7.4. Consolidated Cost Summary 87
7.5. Determination of Electromechanical and civil Cost for option III 89
7.6. Feasibility Analysis of Option I, Option II and Option III 90
7.6.1 Option I: Financial Feasibility and Emission Analysis (RETScreen Output) 90
7.6.2 Option II – Financial Feasibility and Emission Analysis 94
7.6.3 Option III – Financial Feasibility and Emission Analysis 97
CHAPTER EIGHT 101
COMPARISON ANALYSIS AND DISCUSSION 101
8.1 Introduction 101
8.2 Comparative Analysis 101
8.3 Discussion 104
CHAPTER NINE 108
SUMMARY OF MAJOR FINDINGS, CONCLUSION AND RECOMMENDATIONS 108
9.1 Introduction 108
9.2 Summary of Major Findings 108
9.3 Conclusions 109
9.4 Technical Specifications (Option II) 110
9.5 Recommendations 112
REFERENCES 114

List of Tables

Table 2.1 US Retrofitting Non-Powered Dams (NPDs) for hydropower generation........24

Table 4.1 Salient Features..40

Table 5.1 10-day reservoir evaporation and gross irrigation releases data used in simulation…………………………………………………………………………..........43

Table 5.2 Flow and level of excedence...44

Table 6.1 Irrigation and Hydro operation scenario..64

Table 6.2 Types of Turbines and specific speed...64

Table 6.3 Determination of Design flow from FDC..66

Table 6.4 Option I: Power and energy computations 70

Table 6.5 Option II: Power and energy computations..711

Table 6.6 Runner diameter, Velocity Coefficient and specific speed..............................73

Table 6.7 Dimensioning Scroll case 75

Table 6.8 Dimensioning Daft Tube 76

Table 7.1 Powerhouse civil cost for option I (USD) 833

Table 7.2 Powerhouse civil cost for option II (USD)...844

Table 7.3 Tailrace civil works cost for option I and II (USD).......................................844

Table 7.4 Summary of cost for option I and II 88

Table 7.5 Option I: project preview...900

Table 7.7 Option I: Financial structure..922

Table 7.8 Option I: Financial feasibility indicators..922

Table 7.9 Option I: Levelized Cost of Energy (LCOE)..933

Table 7.10 Option I: Greenhouse gas emission 933

Table 7.11 Option II: Project overview 944

Table 7.12 Option II: Capital and operating cost..95

Table 7.13 Option II: Financial structure...95

Table 7.14 Option II: Financial feasibility indicators..96

Table 7.15 Option II: Levelized Cost of Energy (LCOE) 96

Table 7.16 Option II: Greenhouse gas emission...96

Table 7.17 Option III: Project overview..97

Table 7.18 Option III: Capital and operating costs 98
Table 7.19 Option III: Financial structure 99
Table 7.20 Option III: Financial feasibility indicators...99
Table 7.21 Option III: Levelized Cost of Energy (LCOE) 1000
Table 7.22 Option III: Greenhouse gas emission..1000
Table 8.1 Comparative Evaluation of Options I, II & III 1033

List of Figures

Figure 2.1 Conceptual framework (Source: Own conceptual framework) 28

Figure 5.2 Flow Duration Curve graph 45

Figure 6.1 Option I Layout arrangement of Independent proposed tunnel/penstock and Location of Power House 477

Figure 6.2 Option I Schematic 477

Figure 6.3 Option II Layout arrangement of shared penstock with irrigation tunnel for power generation and Location of Power House 498

Figure 6.4 Option II Schematic 49

Figure 6.5 Option III Layout arrangement of Power House at cross regulator without connection reservoir head and without penstock 50

Figure 6.6 Option III Schematic..51

Figure 6.7. Hydro-turbines characteristics in terms of water head and flow rate. 58

Figure 6.8 Efficiency curve Turbines..66

Figure 6.9 Kaplan Runner Dimensions 733

Figure 6.10 Main spiral case Dimension...744

Figure 6.11 Main Draft Tube Dimension...76

Fig. 7.1 Electromechanical cost estimate curve 86

Abbreviations and Acronyms

BOQ: Bill of Quantities

CAPEX: Capital expenditure

CFD: Computational Fluid Dynamics

DOE: Department of Energy

EC: Europeans Calendar

ELC: Electronic Load Controller

FDC: Flow Duration Curve

FERC: Federal Energy Regulatory Commission

FSI: Fluid Structure Interaction

ICOLD: International Commission on Large Dams

IRENA: International Renewable Energy Agency

LCOE: Levelized Cost of Energy

MoWR: Ministry Of Water Resources

NACA: (Used for airfoil design)

NPD: Non-Powered Dam

NPV: Net Present Value

OPEX: Operational expenditure

PPP: Public-Private Partnerships

RBKP: Runner Blade of Kaplan Turbine

SDG: Sustainable Development Goal

SHP: Small Hydroelectric Power

USBR: US Bureau of Reclamation

USD: United States Dollar

CHAPTER ONE
INTRODUCTION

1.1 Background of the Study

Hydropower remains one of the most important renewable energy sources globally, offering countries a stable, low carbon, and economically competitive option for electricity generation. In Africa, and particularly in Ethiopia, hydropower plays a central role in national electrification and economic development strategies. Ethiopia's power system is dominated by hydropower, which accounts for more than ninety percent of total electricity generation (Kuma & Ershadi, 2021). Despite this potential, many existing dams in the country are designed primarily for irrigation or flood control, and therefore do not contribute to national electricity production. In recent years, there has been a growing interest in retrofitting non-power dams to generate hydropower as a cost effective means to expand renewable energy supply without constructing entirely new infrastructure (International Renewable Energy Agency [IRENA], 2020).

Retrofitting existing dams offers several advantages. Since civil works, land acquisition, and water storage structures are already in place, the marginal investment required to add power generating units is significantly lower compared to building new hydropower dams. According to IRENA (2020), retrofitted hydropower projects often achieve lower Levelized Cost of Energy (LCOE) because they utilize existing reservoirs and spillways, reduce construction risk, and shorten implementation time. Globally, more than seventy percent of cost effective hydropower expansion potential lies in upgrading or retrofitting existing dams rather than new dam construction (Zarfl et al., 2015). This makes retrofitting particularly attractive for countries like Ethiopia where water resource development has historically focused on irrigation and flood management.

Tendaho Dam, located in the lower Awash Basin, is one of Ethiopia's major irrigation reservoirs. Constructed mainly to support large scale sugarcane production and to supply water for community irrigation, the dam controls considerable flows of the Awash River. Although originally designed for irrigation, the reservoir holds substantial hydraulic potential that remains unused for electricity production. Studies on similar irrigation dams in East Africa have shown that retrofitting such structures with low-head or medium-head hydropower turbines can meaningfully increase national electricity generation without affecting their primary function (Laghari et al., 2019). However, achieving this balance requires careful engineering analysis because altering flow regimes may influence irrigation releases, sediment transport, and downstream water allocation.

In the context of Ethiopia, water allocation is especially sensitive due to competing demands from agriculture, domestic consumption, and environmental needs. Research on water-energy-food interactions in Ethiopian basins demonstrates that alterations in reservoir operations can cause trade offs between hydropower generation and irrigation output, particularly during dry seasons (Gebremeskel et al., 2020). Because Tendaho Dam supports irrigation in a very dry and water scarce region, any hydropower retrofit must guarantee that irrigation supply is not compromised. This requires detailed hydraulic and operational modelling capable of determining how much energy can be generated while maintaining the mandated irrigation flow regime.

Furthermore, global evidence suggests that hydropower retrofits must address both technical and economic performance indicators. Engineering studies show that low head turbines such as Kaplan, Bulb, or axial flow turbines are generally suitable for irrigation dams because they can operate efficiently with variable flows and small hydraulic heads (Carvalho et al., 2021). From an economic perspective, the viability of retrofitting depends on achieving a favourable Net Present Value (NPV) and keeping the LCOE within competitive ranges. Recent global benchmarks provided by IRENA (2020) indicate that retrofitted small hydropower plants commonly achieve LCOE values below 0.05 USD per kilowatt hour. Ethiopia's national hydropower LCOE values also fall within this competitive range, suggesting that a Tendaho retrofit could be economically feasible if design and operational parameters are optimized.

However, feasibility cannot be assumed. Real world evidence from similar retrofits shows that insufficient flow availability, seasonal variation, sedimentation, and turbine selection can reduce expected generation output (Kuriqi et al., 2020). In addition, economic performance is sensitive to discount rates, investment costs, operation and maintenance costs, and expected energy prices. Therefore, a rigorous financial modelling framework is required to determine whether the retrofit improves long-term economic return and whether it contributes to recovery of sunk investment costs associated with the original irrigation infrastructure.

Environmental and operational risks must also be considered. Studies on multipurpose dams emphasize that adding hydropower facilities can alter downstream ecological conditions if not carefully managed (Winemiller et al., 2016). For irrigation dams, the timing and volume of releases are essential for agricultural productivity. Any hydropower operation must follow run of river principles or non-interference strategies to avoid conflict with irrigation schedules. Engineering measures such as bypass conduits, flow control structures, and turbine regulators may be used to maintain reliable irrigation releases while enabling energy generation (Carvalho et al., 2021).

Given these global lessons, assessing the feasibility of hydropower retrofitting at Tendaho Dam is both timely and important. Ethiopia faces increasing energy demand due to population growth, industrialization, and electrification initiatives. At the same time, constructing new hydropower dams faces financial, environmental, and political constraints. Retrofitting an existing structure such as Tendaho could provide a strategic opportunity to expand clean energy supply at low cost and low environmental impact. Yet this can only succeed if the retrofit is technically sound, economically justified, and operationally compatible with irrigation requirements.

Therefore, investigating the engineering alternatives, evaluating the associated economic benefits, conducting detailed hydraulic modelling, and determining the optimal operational strategy are all essential components for determining feasibility. A comprehensive assessment will support evidence based decision making for policymakers, water resource planners, and power sector authorities seeking to maximize the country's renewable energy potential while safeguarding agricultural productivity in the Awash Basin.

1.2 Statement of the Problem

Ethiopia is facing a growing gap between electricity supply and the fast-rising demand caused by population growth, industrial expansion, and rural electrification. Even though the country has large hydropower potential, many of the major dams were built for irrigation, water supply, or flood control, not for power generation (Kuma & Ershadi, 2021). Because of this, huge amounts of water are released every year without producing electricity. International studies show that adding hydropower units to existing irrigation dams can be a cost-effective and low-impact solution since the civil structures already exist (IRENA, 2021). However, in Ethiopia there is still very little detailed research that evaluates the real technical and economic feasibility of retrofitting specific dams for hydropower.

The Tendaho Dam in the Awash Basin is one of the clearest examples of this unused potential. The dam stores a large volume of water and releases high flows for irrigation, but no study has examined whether these flows could be used for hydropower without affecting irrigation activities. Previous works have focused mainly on spillway behaviour, stability under rapid drawdown and earthquakes, and dam-break modelling (Demeke et al., 2019; Ashebir, 2018; Tadesse, 2015). Although these studies are valuable for safety, they do not assess hydropower potential, turbine options, financial returns, or the relationship between hydropower operation and irrigation needs. As a result, water continues to be released from the dam without producing energy, while surrounding communities continue to face unreliable electricity.

Similar limitations appear in other Ethiopian hydropower studies. For example, Temesgen Ayalew (2021) assessed a micro-hydropower project on the Ganga River but did not calculate penstock length or head losses, which are essential for estimating real power output. The study also used an inappropriate citation the Population and Housing Census, to justify penstock thickness, even though such calculations must follow engineering standards. In addition, the design flow was not justified with hydrological methods like Q90 or Q50. These gaps make the results technically uncertain.

Another example is the work by Ezra Girmachew (2023) on the Akaki River. This study used detailed modelling tools such as RETScreen and MATLAB SIMULINK and correctly selected a Kaplan turbine for a low-head site. However, the financial assumptions were not realistic. The capital cost per kilowatt was extremely high 37,165 USD/KW, and the selling price of electricity was much higher than national values (FDRE, 2020; IRENA, 2012). Because of this, the financial indicators such as NPV and payback period appeared positive even though the actual Levelized Cost of Energy (LCOE) was very high. The study also treated penstock length as a design choice, even though it is fixed by the site layout. These issues show the need for more accurate engineering and economic methods.

Earlier work on Tendaho also shows major inconsistencies. Ashenafi Wondimu (2014) tried to estimate monthly energy generation using a reservoir operation model but used an unrealistic head of 39 m and inconsistent pipe length values, while in contrary led to an underestimated 7GWh anaual energy output. The study did not specify turbine type, installed capacity, or any design details, and it ignored the official reservoir operating rule curve prepared by WWDSSE. This makes the results difficult to apply in real operation. The present research improves on this by using accurate geometric data and ensuring that hydropower discharge returns to the irrigation system so irrigation is not affected.

Some international references also highlight gaps that need to be addressed. The South African study by van Vuuren et al. (2011) provides a good general feasibility model but uses data from 2011 and does not include modern design optimization methods like MCDM or genetic algorithms. The Gilgel-Abbay hydropower report by Gedion Tasew also shows confusion between power factor (electrical) and plant factor (operational) and uses an unrealistic 100-year economic period, which can unrealistically inflate NPV.

Recent Ethiopian studies on Arjo Dedessa and Ribb dams (Kishe, 2023; Addisu Worku Bezabih, 2023) confirm that these dams have strong hydropower potential—about 6.75 MW for Arjo Dedessa and 5.53 MW for Ribb. However, both studies stop at hydrological assessment and do not provide site layout, turbine selection, head-loss analysis, or any financial evaluation such as NPV or LCOE. This means the studies identify "what is possible," but not "how to build it" or "whether it is economically viable."

Across all these cases, one major gap becomes clear: most Ethiopian studies describe the hydrological potential but do not integrate technical design, hydraulic analysis, economic modelling, and operational compatibility. Because of this, decision-makers cannot determine whether retrofitting dams like Tendaho is truly feasible or financially attractive.

This research addresses that missing link by providing a complete and realistic feasibility assessment for hydropower retrofitting at Tendaho Dam. It combines accurate hydraulic modelling, engineering design, economic evaluation, and irrigation-compatibility analysis to support Ethiopia's effort to expand renewable energy while protecting irrigation reliability.

1.3 Objective of the Study

1.3.1 General Objective of the Study

The general objective of the study is to evaluate the technical, economic, and operational viability of retrofitting the Tendaho Dam for hydropower generation while ensuring adherence to the established irrigation flow regime.

1.3.2 Specific Objectives of the Study

The study is guided by the following specific objectives:

1) To determine the extent to which technical retrofit measures can optimize the Tendaho Dam infrastructure to achieve maximum power and energy generation levels, without compromising the mandated irrigation releases.
2) To identify and evaluate engineering alternatives that can enhance the Tendaho Dam project's Net Present Value (NPV) and contribute to the recovery of sunk investment costs.
3) To assess whether the proposed hydropower retrofit options can reduce the Levelized Cost of Energy (LCOE) below the IRENA benchmark range of 0.01–0.05 USD/kWh.
4) To examine the financial modelling framework that demonstrates the economic superiority of the Tendaho Dam retrofit in relation to the national LCOE and IRENA standards.
5) To investigate the operational and hydraulic strategies required to avoid interference between hydropower generation and the established irrigation flow regime at the Tendaho Dam.

1.4 Research Questions

This study addresses the following research questions, each grounded in the context of the Tendaho Dam project:

1) To what extent can the existing Tendaho Dam infrastructure be technically retrofitted to enhance maximum power and energy generation capacity, while maintaining full compliance with the established irrigation flow requirements?
2) What engineering alternatives are available for the Tendaho Dam project to improve its Net Present Value (NPV) and support the recovery of the sunk investment cost?

3) Can the proposed hydropower retrofit options at the Tendaho Dam reduce the Levelized Cost of Energy (LCOE) to a level below the 0.01–0.05 USD/kWh benchmark set by IRENA?
4) Which financial modelling approach best demonstrates the economic advantage of the Tendaho Dam hydropower retrofit relative to the prevailing high national LCOE, while meeting IRENA's criteria for small-scale hydropower?
5) What operational and hydraulic strategies can be implemented to ensure that hydropower generation at the Tendaho Dam does not conflict with, or diminish, the mandated irrigation flow regime?
6)

1.5 Significance of the Study

The study is significant for several reasons. First, Ethiopia continues to experience a rapid increase in electricity demand due to population growth, urbanisation, and industrial expansion. Expanding hydropower generation through retrofitting existing dams offers a practical and low-cost approach to strengthening the national energy system. By examining Tendaho Dam, this research provides evidence on how irrigation reservoirs can be transformed into multipurpose assets without constructing new dams, which often require large financial investments and lengthy approval processes.

Second, the study contributes to national efforts to diversify renewable energy sources. Since civil works at Tendaho Dam are already in place, retrofitting has the potential to produce clean energy with much lower environmental and social impacts compared to new hydropower projects. Findings from the study can support decision-makers seeking efficient ways to expand green energy while protecting communities and natural resources.

Third, the economic analysis offers valuable insights into the financial performance of retrofit projects in Ethiopia. By comparing potential LCOE values with national and international benchmarks, the study helps clarify whether hydropower retrofitting can compete with other renewable technologies. This can guide policymakers, investors, and development partners in prioritising future energy investments.

Moreover, the study is significant for the irrigation sector. Tendaho Dam plays a major role in supporting agriculture in the lower Awash Basin, and any modification must protect irrigation reliability. By examining operational strategies that prevent interference with water delivery, the study supports integrated water resource management and promotes harmony between energy production and agricultural development.

Finally, the research expands the academic literature on multipurpose water infrastructure in Ethiopia. It provides a detailed case study that future researchers, engineers, and planners can use when evaluating similar retrofit opportunities across the country's irrigation and flood control dams.

1.6 Scope of the Study

This study focuses on evaluating the technical, economic, and operational feasibility of retrofitting the Tendaho Dam for hydropower generation without interrupting its primary purpose of supplying irrigation water. The research is limited to the Tendaho Dam site and its immediate hydraulic system, including the reservoir, main canal intake structures, and the existing outlet works that control irrigation releases. The study does not attempt to redesign the entire dam or propose major structural modifications beyond what is practical and financially reasonable for a retrofit project.

The technical scope includes an assessment of flow availability, hydraulic head, turbine suitability, and alternative retrofit configurations that match the dam's irrigation-based operating regime. Engineering analysis focuses on identifying low-head and run-of-river compatible technologies that can operate within the existing water distribution schedule. This investigation also considers how variable river inflow, sedimentation, and seasonal irrigation requirements influence potential energy generation.

The economic scope examines the financial viability of the retrofit options through standard indicators such as Net Present Value, Levelized Cost of Energy, internal rate of return, and payback period. The study uses current national electricity tariffs, investment cost benchmarks, and IRENA LCOE standards for small hydropower. It does not include broader macroeconomic effects such as national employment, export earnings, or long-term industrial development.

Operational scope covers the strategies required to prevent interference with irrigation flows. This includes evaluating operating rules, flow release timing, and hydraulic control structures. Environmental impacts, social considerations, and long-term climate projections are acknowledged but not fully assessed, as they fall outside the main objective of determining retrofit feasibility. In this way, the study remains focused on determining whether hydropower generation at Tendaho Dam is technically possible, economically justified, and operationally acceptable under current irrigation demands.

1.7 Limitations of the Study

The hydrological analysis relied mainly on historical flow records collected from the long-established Awash Basin monitoring network. Although the network includes many gauges, several stations had incomplete data or different installation periods. The study did not have the opportunity to conduct new long-term field measurements, which may affect the accuracy of the flow duration curve, sediment estimates, and dependable flow values.

Another limitation could be the level of sedimentation. Sedimentation estimates for Tendaho Reservoir differ widely among previous investigations, ranging from 20 Mm^3 to 30 Mm^3 per year. Since the study depended on these previous assessments, the true level of sedimentation may be higher or lower. This introduces uncertainty in the long-term performance of the intake, penstock, and turbine.

Only a short reconnaissance visit of two days was conducted at the dam site. During this visit, observations were limited to visual inspection and discussions with engineers. More detailed geotechnical, structural, hydraulic, and sediment measurements could not be performed because of time and access constraints.

Several design parameters, such as friction coefficients, pipe roughness, minor loss coefficients, and turbine efficiency values, were derived from textbook values and comparable studies rather than site-specific tests.

The cost assessment relied on typical price benchmarks from IRENA reports, historical Tendaho project cost records, and RETScreen default economic parameters rather than quotations from current suppliers or contractors. As a result, real project costs may differ once updated market prices, inflation, transport conditions, or procurement realities are considered.

The study focused mainly on engineering and economic feasibility. Broader environmental and social assessments such as ecological effects, community impacts, and detailed environmental flow analysis were beyond the scope of this study. Finally the research examined only the three retrofit scenarios already considered during the field visit (dedicated waterway, bifurcated flow, and channel utilization strategies). Other innovative retrofit configurations or turbine arrangements were not assessed.

1.8 Definition of Key Terms

Computational Fluid Dynamics (CFD)*:* Computational Fluid Dynamics is a numerical approach used to simulate fluid flow, turbulence, pressure distribution, and energy transfer by solving the governing Navier–Stokes equations. In hydropower engineering, CFD helps analyse turbine runners, scroll cases, draft tubes, and hydraulic losses to improve design and efficiency **(**Haider, 2024**).**

Electronic Load Controller (ELC)*: A*n electronic load controller is a stabilizing device used in small hydropower schemes to maintain constant generator frequency and voltage. It regulates excess energy by diverting surplus power to a ballast or dump load when consumer demand decreases **(**Ndukwe et al., 2024).

Fluid-Structure Interaction (FSI)*:* Fluid-structure interaction refers to the mutual interaction between a deformable or movable solid structure and the surrounding fluid flow. In hydropower systems, FSI analysis is essential for predicting runner blade deformation, vibration risks, and transient loading (Hirschhorn et al., 2020).

Mass Density (ρ)*:* Mass density, symbolized by ρ, is the mass of a substance per unit volume and is a fundamental property used for computing pressure, buoyancy, and gravitational energy in hydraulic systems **(**NIST, 2019).

Run-of-River*:* Run-of-river refers to a hydropower system that operates with minimal storage, generating electricity from the natural continuous flow of a river. Energy output varies with seasonal discharge and depends on natural inflow **(**IRENA**,** 2018**).**

Runner: The runner is the rotating component of a hydraulic turbine that converts water energy into mechanical rotational power. Runner geometry determines efficiency and suitability for different heads and flow conditions **(**Quaranta, 2022**).**

Runner Blade of Kaplan Turbine (RBKP)*:* A Kaplan turbine runner blade is an adjustable-pitch blade designed for low-head, high-flow hydropower sites. Its variable blade angle allows the turbine to sustain high efficiency across a wide range of flows **(**Sathish, 2024**).**

Scroll Case*:* A scroll case, also called a spiral casing, is the inlet structure surrounding a reaction turbine that distributes water uniformly around the circumference before entering the guide vanes. Its geometry ensures even pressure distribution **(**Carvalho et al., 2021**).**

Small Hydro*:* Small hydro refers to hydropower systems typically below 50 MW capacity, depending on national definitions. These systems support rural electrification and grid reinforcement with minimal environmental impact **(**Laghari et al., 2019**).**

Specific Gravity (s.g.): Specific gravity, also known as relative density, is the ratio of a material's density to that of water at 4°C. It is commonly used in sediment transport, hydraulic engineering, and material classification **(**NIST, 2019)**.**

Specific Speed (Ns)*:* Specific speed is a dimensionless parameter used to classify and select turbines based on rotational speed, flow rate, and head. It helps determine whether a Kaplan, Francis, or Pelton turbine is suitable for a site **(**Kumar & Saini, 2016**).**

Specific Weight (γ)*:* Specific weight, denoted by γ, is the weight per unit volume of a substance and is calculated as density multiplied by gravitational acceleration. It is used in head calculations and hydrostatic pressure computations **(**Munson et al., 2020**).**

Tail Water: Tail water refers to the water level downstream of a turbine outlet or draft tube. The elevation of the tail water determines the effective net head available for power generation **(**Zhang et al., 2023).

Turbine: A turbine is a hydraulic machine that converts the kinetic and potential energy of water into mechanical rotational energy. Turbines are categorized as reaction or impulse types based on how water transfers energy to the runner**. (**Quaranta, 2022)

Velocity Head: Velocity head is the kinetic energy per unit weight of flowing water, calculated as. It represents the energy associated with water velocity and is used in Bernoulli-based hydraulic analysis (Munson et al., 2020).

1.9 Organization of the Thesis

The thesis is organized into nine chapters that collectively evaluate the technical, hydraulic, and economic feasibility of retrofitting hydropower at Tendaho Dam. Chapter One introduces the study context, outlines the problem of underutilized infrastructure, and defines the research questions, objectives, and overall structure. Chapter Two reviews relevant literature on non-powered dams, small hydropower retrofitting, turbine selection, and economic evaluation, while identifying gaps addressed by the study. Chapter Three presents the methodological framework, covering data collection, hydraulic and engineering analyses, and financial appraisal using RETScreen. Chapters Four and Five describe the existing dam structures and hydrological conditions, forming the basis for design flow and capacity assessment. Chapter Six details the technical design and component selection for the retrofit options. Chapter Seven examines financial performance and cost assumptions. Chapter Eight compares three retrofit alternatives across technical and economic criteria. Chapter Nine synthesizes the findings, recommends the most viable option, and discusses broader policy relevance.

CHAPTER TWO

REVIEW OF RELATED LITERATURE

2.1 Introduction

This chapter is critically examine various literatures pertaining retrofitting existing non-powered dams for hydropower in respect to engineering and economic feasibility from global, regional and local retrofitting experiences. It is divided into four main sections; which the first section discusses theoretical framework. The second and third sections explore empirical evidence from global, & regional studies and selected cases on the feasibility studies on retrofitting of existing non-powered dams for hydropower projects. The last section deals with the conceptual framework of the study – discussing the different phases and parameters the study carried out in order to answer the research questions.

2.2 Theoretical Framework

Retrofitting existing non-powered dams (NPDs) for hydropower is a highly attractive strategy because it requires minimal intervention compared to the massive undertaking of building an entirely new dam and power plant. A significant majority of the world's large dams were built for purposes other than power, such as irrigation and flood control. Statistics from the ICOLD database (as of 2019) show that this untapped potential is global: nearly 90% of large dams in Africa, about 75% in Asia, and close to 60% in Europe are currently not used for hydropower. Retrofitting is the process of adding or expanding hydroelectric power generation capabilities to these existing, underutilized structures. However, dams originally built for other purposes have distinct water regulation patterns, making the assessment of water balance over a multi-year period a critical part of the evaluation to ensure compatibility with existing demands. This global opportunity is substantial, with a linear regression analysis estimating a total global retrofitting potential of 277.33 TWh (Fjøsne, 2020).

The idea of transforming an existing dam or water infrastructure into a hydropower source is grounded in the concept that many dams originally built for irrigation or water supply may remain underutilized but carry latent potential for energy production. The study by Okang, Bakken, and Bor (2023) analyzed eleven non-powered dams in the Büyük Menderes River Basin and found that with only minor interventions, these dams could deliver a combined installed capacity of 4.4 MW and annual generation of 38.7 GWh, with favorable capital cost relative to a new dam, and positive net present value (Okang et al., 2023). This evidence supports the theory of infrastructure reuse, where existing civil works and reservoirs represent under-exploited resources for renewable energy.

However, the viability of such retrofitted hydropower depends on hydrological and hydraulic realities. Hydropower generation fundamentally requires sufficient water discharge (flow) and hydraulic head (vertical drop). Where dams were not designed for energy purposes, these parameters may not guarantee stable and continuous production. The work on the Ribb irrigation dam in Amhara region, Ethiopia, illustrates this constraint. The study estimated a net head of 70.37 m and mean flow of 14.6331 m^3/s, leading to a theoretical small hydropower capacity of 5.53 MW under optimal conditions (Bezabih, 2021). However, the same study noted that hydrological variability and seasonal fluctuation of flow strongly affect generation reliability, revealing that even dams with good head may face intermittent output if flow is not stable (Bezabih, 2021). Thus the hydrological-hydraulic feasibility theory remains central: retrofit is only viable if both head and sufficiently reliable flow exist.

In many contexts flow or head may be marginal. For those circumstances technological adaptability becomes essential. Traditional turbines optimized for high head may not perform well under low head or variable flow regimes. The review by Zhou and Deng (2017) on ultra-low-head (ULH) hydroelectric technologies shows that advances in turbine design, simplified civil works, and use of flow velocity rather than large head can make hydro generation feasible where head is minimal (Zhou & Deng, 2017). This theory widens the spectrum of candidate sites for retrofit: even modest or low-drop dams or streams may yield usable energy, provided the right turbine technology is selected.

Beyond technical and hydraulic feasibility, economic viability is another critical theoretical pillar. Since retrofit uses pre-existing infrastructure, capital cost can be much lower than constructing a new dam. In the Turkish NPD study, retrofit cost across 11 dams was modest (compared to new construction), and overall net present value was positive (Okang et al., 2023). In resource-constrained settings, this cost advantage supports retrofit as a cost-effective alternative for renewable energy generation.

Nevertheless, economic feasibility depends on reliability of water supply, stable operation, and demand for electricity. If flow is seasonal or intermittent, energy output and revenue may fluctuate; maintenance and operational cost of retrofit turbines may be high; local demand for electricity may not guarantee return on investment. Thus, technical, hydrological, and economic conditions must align for retrofit to be successful.

In addition, small-scale hydropower in rural or remote areas can have social and development implications. The case study from a small dam in Horo Guduru Wollega zone, Ethiopia, shows that although rural hydropower dams aim to support electrification of nearby communities, many households remained without electricity supply due to challenges such as distance from grid lines and affordability (Soressa & Gebre-Egziabher, 2024). This highlights that retrofit projects must consider not only generation potential but also distribution, access, equity, and institutional capacity. Social outcome is therefore part of the theoretical framework supporting or constraining retrofit.

Another dimension is that some dams or water infrastructures may have very low hydraulic head or limited discharge, but may yet support micro- or pico-hydropower if modern low-head turbines are used. The review by Chaulagain, Poudel, and Maharjan (2023) finds that non-conventional turbines appropriate for ultra-low-head or low-flow conditions exist and may enable harnessing energy from small-scale water flows (Chaulagain et al., 2023). This shows theoretical potential for retrofit beyond classical "high-head, large-flow" dams, widening the scope of retrofit to small, degraded or underutilized dams or irrigation canals.

Given these theoretical pillars infrastructure reuse, hydrological-hydraulic feasibility, technological adaptability, economic viability, and socio-development potential; a coherent framework emerges for evaluating retrofit feasibility of the Tendaho dam. The approach must assess reservoir and flow data (flow timing, variability, head), evaluate turbine and mechanical design suited to local conditions, estimate potential output and economic return, and examine social and environmental implications including access to electricity, maintenance, water use, and demand.

Moreover, retrofit feasibility must include a comparative analysis: assessing output under different scenarios (dry vs. wet season, high flow vs. low flow), exploring different turbine and design options, projecting financial return over time, and evaluating risks (flow variability, maintenance, institutional capacity). This systematic, scenario-based analysis aligns with the theoretical framework.

In Ethiopia and similar developing-country contexts, where many irrigation or storage dams remain underutilized or water distribution is incomplete, this framework suggests that retrofit offers a practical pathway to convert idle infrastructure into energy assets, advancing renewable energy, improving rural electrification, and optimizing resource use. The Ribb dam study (Bezabih, 2021) serves as empirical precedent, and global reviews (Zhou & Deng, 2017; Chaulagain et al., 2023; Okang et al., 2023) provide technological and economic context.

At the same time, the social case study of rural electrification in Horo Guduru zone (Soressa & Gebre-Egziabher, 2024) warns that generation potential alone is insufficient; distribution, access, and social equity must be considered in retrofit planning. This underscores that theoretical feasibility does not guarantee practical success without attention to institutional, demand, and distribution factors.

Thus, the theoretical framework for the thesis comprises several interlocking theories and empirical observations: infrastructure reuse and resource optimization; hydrological-hydraulic feasibility; technological adaptation; economic viability; social and development impact; and integrated scenario-based analysis. Using this framework, the research questions, regarding technical suitability, power potential, configuration alternatives, economic justification become grounded in both theory and evidence.

Thus, the literature confirms that existing dams and non-powered water infrastructures are not intrinsically useless; with appropriate assessment and design they may deliver renewable energy. However, retrofit success depends on alignment of hydrological, technical, economic, and social conditions. A carefully designed and context-aware feasibility study, following this theoretical framework, can reveal whether a given dam such as Tendaho Dam can be repurposed as a hydropower asset.

2.3 Engineering Theoretical Background

Mathematical and engineering foundations including power equations, head and loss calculations, Flow Duration Curve methodology, and turbine efficiency principles. The issue of combining irrigation and hydropower into truly "multipurpose" operations globally stems from a fundamental operational conflict that necessitates diametrically opposing water management strategies (Schmitt and Rosa, 2024). The core conflict is that irrigation demands reliable volume and a consistent high reservoir level (for supply guarantees and maintaining head for gravity-fed canals), which subsequently reduces the maximum possible hydraulic head available for the turbine, thus lowering power output and efficiency (Arunkumar and Jothiprakash, 2012). Conversely, hydropower requires the flexibility to rapidly adjust discharge to meet volatile peak electricity demand, and often needs to draw down the reservoir to maximize energy value, a schedule that compromises the steady volume required for the agricultural calendar (Schmitt and Rosa, 2024). This inherent conflict historically leads to suboptimal performance for one or both uses. Consequently, retrofitting non-powered dams has emerged as a major global trend "low-hanging fruit", because it leverages sunk capital and existing civil works, significantly reducing the Capital Expenditure (CAPEX) and eliminating major project risks like land acquisition and initial environmental opposition (Schmitt and Rosa, 2024).

Furthermore, retrofitting satisfies the urgent global imperative to meet renewable energy targets by providing an immediate, dispatch able power source that uses water that is already being released, representing a highly cost-effective and low-risk source of new hydropower capacity globally (IREA, 2012). Therefore, the modern design trend required to address these conflicts involves adopting highly independent hydraulic configurations and stringent operational protocols that guarantee non-interference with the irrigation schedule, making the selection of the optimal retrofit option the critical step in reconciling these competing demands

The foundational principle of hydropower generation is mathematically defined by the hydraulic power equation, where power output (P) is directly proportional to the density of water (ρ), gravity (g), design flow (Q), net head ($Hnet$), and the total system efficiency (h):

$$P = \rho g\ Q\ Hh$$

The critical variable, Design Flow (Q), is not a static measure but is accurately determined from the Flow Duration Curve (FDC), which utilizes a large historical dataset to determine the optimal flow exceedance (e.g., Q30) that maximizes annual energy generation (Searcy, 1969).

2.3.1. Head and Net Head & Flow Duration Curve (FDC)

The usable head, Net Head (*Htnet*), is crucial for efficiency and is calculated as the Gross Static Head (the vertical difference between the reservoir water level and the tail water level) minus the total system head losses ($h_{L,total}$):

$$H_{net} = H_{static} - h_{L,total}$$

These losses are meticulously quantified into two categories: major losses, which account for friction along the length of the penstock, determined using the Darcy-Weisbach formula (h_f), and minor losses, which account for energy dissipation at pipe fittings, bends, and transitions, quantified by a loss coefficient (K) (Garde and Ranga Raju, 2000).

$$\text{Major Loss:} h_f = f . L/D . V^2/2g$$

$$\text{Minor Loss:} h_m = K . V^2/2g$$

Finally, the system's total efficiency (η) is highly dependent on the turbine selection; the Kaplan turbine is chosen for its suitability in low-to-medium head environments because its adjustable blades and guide vanes allow it to maintain an exceptionally high hydraulic efficiency, typically ranging from 88% to 94%, across a wide operational flow range, which is essential for maximizing output from the variable flow defined by the FDC (Sheppard and Aris, 2017)

FDC is an indispensable analytical tool in hydropower studies that transforms non-chronological stream flow data into a cumulative frequency curve, providing a probabilistic view of the hydrological resource. This curve is crucial because it smooths out the temporal variations (daily, seasonal) found in raw flow data to reveal the dependable flow characteristics of the water source, which is the foundational input for defining the plant's design flow (*Qd*) and calculating Annual Energy Production (AEP). As established by methodological precedents, such as the work published by the USGS (Searcy, 1969), the FDC is the essential instrument for design flow determination: selecting a flow equaled or exceeded 95% of the time (Q95) is used for guaranteeing firm power (continuous output), while a lower exceedance flow (e.g., Q30) is chosen to maximize annual energy generation for grid integration. The methodology typically relies on the statistically rigorous Calendar-Year Method *t*, where the entire dataset of flow discharges is arranged in descending order and assigned a rank (M) to calculate the percentage exceedance (*P*) using the Weibull formula (P=(N+1)/M×100%). For this thesis, the FDC methodology is critically adapted: the "stream flow" input is not the raw river flow, but the constrained and controlled irrigation outlet flow demand. This adaptation ensures the hydropower scheme's FDC accurately models the existing hydraulic constraint, thereby guaranteeing that the derived power potential is calculated only from the available release and will not conflict with the primary irrigation operation.

Methodological Precedent: Searcy's publication establishes two principal construction methods the Calendar-Year Method and the Total-Period Method providing methodological rigor. The use of a Total-Period Method, which ranks the entire dataset, is generally preferred for ensuring a statistically representative curve for long-term power assessment

2.3.2 Efficiency of Hydro Turbine

The efficiency curve shown below in Figure 6.5 of a hydro turbine (*h*) is a critical metric for annual energy production, and its characteristic curve is the primary reason why the Kaplan turbine and cross flow is uniquely suitable for projects constrained by highly variable flows, such as those governed by an irrigation schedule. The efficiency of a hydro turbine is a measure of its ability to convert the hydraulic energy available in the water stream into mechanical energy at the turbine shaft. This efficiency varies significantly with the flow rate (Q) relative to the machine's designed rated flow (Q_{rated}). For instance, the Francis turbine, a common choice for medium heads—exhibits a high peak efficiency (often over 90%) only over a narrow range near its rated flow, making it highly unsuitable for systems where the flow rate deviates due to irrigation demands (Arunkumar and Jothiprakash, 2012). In stark contrast, the Kaplan turbine is selected specifically for its superior performance in variable flow regimes because it maintains a remarkably flat efficiency curve across a wide variation of flow rates (See Chapter Six). This stability is achieved through its mechanism of double regulation, where both the runner blades and the guide vanes are adjustable, allowing the turbine to dynamically optimize its geometry to match the available flow. This flat efficiency characteristic, which allows for sustained high efficiency (typically 88% to 94%) even when operating at 30% to 40% of its rated flow, is paramount for the retrofit project as it ensures the plant can efficiently harness the available head and flow throughout the entire irrigation season, thereby maximizing energy generation despite the non-manipulate able and variable nature of the water release (Sheppard and Aris, 2017).

2.3.3 Power and Energy Computation

Once the net head is known across the flow duration curve, the output is calculated:

Power Generated (P): The instantaneous electrical power generated is computed at all flow points using the standard hydraulic power formula, incorporating the Net Head and the assumed turbine efficiency.
Annual Energy (E): The total annual energy production is calculated by integrating the computed power output over the entire period defined by the Flow Duration Curve (refer Chapter Six).

2.4 Empirical Evidence

Hydropower retrofitting has emerged as a viable strategy for increasing renewable energy generation while minimizing environmental and financial costs. Globally, the expansion of hydropower has shifted toward retrofitting existing irrigation and multipurpose dams, particularly in regions where new dam construction faces ecological, social, or financial constraints (IRENA, 2021; Quaranta & Hunt, 2022). The concept of utilizing untapped hydraulic potential in irrigation dams is supported by evidence showing that low-head hydropower technologies can convert available flow into electricity without significantly altering the primary function of the reservoirs (Brazzini et al., 2024). Retrofitting projects in both Europe and Africa indicate that irrigation dams possess substantial untapped potential for sustainable power generation when proper hydraulic and operational designs are applied.

Many researches on the technical retrofit feasibility, emphasize that technical compatibility between turbine selection and flow characteristics is critical. Low-head turbines such as Kaplan, bulb, and axial-flow units are suitable for irrigation dams due to their adaptability to variable flow regimes and relatively small hydraulic heads (Quaranta & Hunt, 2022; Demeke et al., 2019). In the context of Tendaho Dam, hydrodynamic modelling shows that available head and flow rates could support turbine installation without compromising structural integrity (Demeke et al., 2019). Similarly, hydrologic analysis of irrigation canals in Spain demonstrated that low-head turbines could be integrated into canal networks to generate electricity while maintaining water delivery schedules for agriculture (Brazzini et al., 2024). These findings highlight the technical potential for retrofitting dams, provided that turbine selection is informed by precise hydraulic modelling and seasonal flow data.

Flow regime analysis is crucial for ensuring that irrigation demands remain uncompromised. Studies have shown that operational modelling, including the use of flow duration curves and seasonal inflow assessment, allows determination of dependable flows available for power generation (Kuriqi et al., 2021). Evidence from small hydropower installations indicates that hydropower can be extracted from irrigation dams without violating agricultural release requirements if non-interference rules are followed. For instance, research in European canal systems demonstrated that strategic scheduling of hydropower operation during surplus flow periods ensures that irrigation volumes remain adequate, preventing negative impacts on crop yields (Brazzini et al., 2024). Therefore, technical retrofit feasibility is contingent not only on hydraulic potential but also on careful operational planning.

Engineering alternatives for improving economic returns, is supported by evidence showing that retrofitted hydropower projects can achieve favourable Net Present Values (NPV) when turbine efficiency, capital cost, and operational practices are optimized (IRENA, 2021; Quaranta & Hunt, 2022). Global experience suggests that civil infrastructure reuse significantly reduces investment requirements, enhancing economic viability. Retrofitting dams avoids the extensive costs associated with land acquisition, reservoir construction, and environmental mitigation required for new projects (IRENA, 2023). For example, studies of European and South African low-head hydropower retrofits revealed that using existing dam structures can reduce overall Levelized Cost of Energy (LCOE) by up to 30 percent compared to greenfield projects (Quaranta & Hunt, 2022; Loots et al., 2015). These findings indicate that dams could achieve positive financial outcomes if retrofit design leverages the existing infrastructure effectively.

Concerning on reduction of LCOE to competitive levels, many empirical studies demonstrate that small hydropower retrofits typically achieve LCOE values ranging from 0.02 to 0.05 USD per kilowatt-hour, depending on flow consistency, turbine efficiency, and installation costs (IRENA, 2021; Brazzini et al., 2024). Economic simulations in Ethiopia suggest that retrofitting existing irrigation dams can lower electricity generation costs compared to constructing new hydropower facilities, especially in areas with high hydraulic potential and stable irrigation demand (IRENA, 2023). Hydropower retrofitting has the potential to fall within this cost range if turbines are chosen according to site-specific hydraulic conditions and capital investments are carefully managed.

International financial modelling approaches, is common practice in retrofitting assessment. Discounted cash flow analysis, NPV, and internal rate of return are standard methods to evaluate project viability (Quaranta & Hunt, 2022). Evidence from run-of-river and low-head hydropower projects highlights the importance of scenario-based modelling, which incorporates variations in inflow, maintenance costs, and electricity price fluctuations (Kuriqi et al., 2021). Sensitivity analysis is particularly valuable for determining how changes in discount rate or turbine cost impact the financial performance of retrofits. Applying such methodologies to Dams enable a comprehensive understanding of economic risks and the potential for recovering sunk investments while ensuring that the Levelized Cost of Energy remains competitive.

On operational and hydraulic strategies it is important, to avoid irrigation interference. Run-of-river operation principles, bypass conduits, and flow control structures are commonly applied to maintain irrigation flow while generating electricity (Demeke et al., 2019; Brazzini et al., 2024). Research indicates that failure to model seasonal variations or downstream demands can result in conflicts between hydropower operation and agricultural requirements, particularly in water-scarce regions (Kuriqi et al., 2021). Therefore, hydropower retrofit feasibility requires integration of hydraulic simulations with irrigation release rules to ensure simultaneous achievement of energy generation and agricultural water provision. Empirical evidence demonstrates that careful calibration of turbine operation, guided by real-time hydrologic data and irrigation schedules, is essential to maintaining this balance.

Environmental considerations also play a role in operational feasibility. Low-head retrofits generally have minimal ecological impact if non-interference operational strategies are adopted, but changes in flow velocity and timing can affect downstream ecosystems (Kuriqi et al., 2021). Studies suggest that integrating environmental flow requirements into operational rules is both feasible and necessary for sustainable hydropower development. The inclusion of sediment management strategies in design further ensures that turbine efficiency is maintained while downstream water quality and irrigation conveyance are not compromised (Demeke et al., 2019).

Overall, the empirical literature indicates that retrofitting existing irrigation dams is technically achievable, economically advantageous, and operationally manageable when guided by evidence-based hydraulic and financial modelling. Low-head turbines, careful flow management, and scenario-based economic evaluation are repeatedly emphasized as key factors for successful implementation (Quaranta & Hunt, 2022; Brazzini et al., 2024; IRENA, 2021). The Tendaho Dam, with its existing infrastructure and significant hydraulic potential, aligns with these global findings, suggesting that a well-designed retrofit can enhance electricity generation, maintain irrigation reliability, and provide positive financial returns. The reviewed literature underscores the necessity of integrating technical, economic, and operational analyses to fully assess feasibility, ensuring that multipurpose dams serve both energy and agricultural objectives effectively.

2.5 Previous Studies on Non-Powered Dam Retrofitting

Recent research has consistently demonstrated the significant, untapped potential for hydropower generation through the retrofitting of existing non-powered dams (NPDs) across different global regions, validating its environmental and economic viability over new construction.

2.5.1 European and North American Case Studies

In Europe, a study by Fjøsne (2020) focused on the Guadalquivir basin in Southern Spain, analysing the potential across 13 non-powered dams. The assessment estimated a total retrofitting hydropower potential of 64.61 GWh with a corresponding capacity of 45.33 MW (Fjøsne, 2020). The economic analysis was particularly compelling: five of the dams were found to be economically viable, collectively representing a Net Present Value (NPV) of 13.67 million EUR (2018) and contributing 46.79 GWh of the total potential (Fjøsne, 2020).

The most recent united states resource assessment by the DOE's Oak Ridge and Idaho National Laboratories analysed 54,391 US non-powered dams (NPDs) and identified a significant total potential for up to 12 GW in capacity addition as shown on Table 2.1 (Hadjerioua et al., 2012; DeNeale et al., 2022).

The experience in the United States provides clear evidence of the versatility and feasibility of retrofitting Non-Powered Dams (NPDs) for hydropower generation. Three key case studies, varying widely in scale, dam type, and development pathway, illustrate successful implementation (DeNeale et al., 2022).

Table 2.1 US Retrofitting Non-Powered Dams (NPDs) for hydropower generation.

Project	**Scale & Head**	**Key Feature & Development Pathway**	**Annual Energy Output**
Hanover Pond Dam, CT	Small (220 kW), Low-Head	Innovative Technology: First US application of an Archimedes screw turbine due to its fish-friendly and low-head applicability. Development was streamlined by obtaining a FERC license exemption due to its small capacity (<10 MW). The project became operational in 2017.	~900 MWh
Meldahl Lock and Dam, KY	Large (105 MW), High-Capacity	Major Infrastructure Addition: This project involved retrofitting a major Ohio River lock and dam. The new powerhouse was built by demolishing and replacing a portion of the original concrete overflow weir. It was developed using the formal Integrated Licensing Process.	~558,000 M Wh
Jordanelle Dam, UT	Medium (13 MW)	Utilizing Existing Provisions: The retrofit capitalized on an existing conduit that had been strategically built into the dam during its original construction specifically for future hydropower additions. The project was developed under a Lease of Power Purchase agreement with the US Bureau of Reclamation (USBR).	~39,000 M Wh

These practical examples demonstrate that successful retrofitting can range from small, environmentally focused projects using innovative low-head turbines to large-scale infrastructure integration, often capitalizing on either inherent dam features (like pre-built conduits) or existing water management agreements(DeNeale et al., 2022). This variety underscores the broad applicability of retrofitting across different dam typologies and ownership structures

2.5.2 African and Asian Case Studies

Research in developing regions further confirms the localized benefits of retrofitting. Kristina (2022) focused on the Thiba Dam in Kenya, which primarily serves irrigation needs, specifically aiming to determine the hydropower potential without interfering with existing water use. The analysis compared two schemes and found that the pipe scheme (utilizing the dam's head directly) was superior, yielding 4.91 MW and proving more financially sound than the diversion weir scheme (3.7 MW). This conclusion strongly supports the principle that retrofitting is more economically beneficial than constructing entirely new hydropower facilities (Kristina, 2022).

Similarly, Okang (2022) conducted a study on the Buyuk Menderes basin in Turkey, investigating the technical, environmental, and economic feasibility across 11 NPDs. Energy simulations projected a collective annual energy output of 38.737 GWh at a total capacity of 4.42 MW. The financial metrics were highly favorable: the projects had a combined capital investment of \$7,892,166, resulting in a substantial total NPV of \$25,576,000 and a highly competitive average Levelized Cost of Energy (LCOE) of \$0.061/kWh (Okang, 2022). The study highlights retrofitting as an untapped, cheaper, and environmentally friendly opportunity to support the global energy transition and advance rural electrification

For retrofitting to be successful, power generation must be optimized around the primary purpose of the dam (e.g., irrigation, flood control). Several studies have successfully integrated these constraints using advanced modelling i.e. in India, the operation of the Koyna reservoir was optimized using a nonlinear programming model to maximize hydropower production while simultaneously ensuring that all irrigation demands were reliably met (Kishe, 2023; Arunkumar, & Jothiprakash, 2012). The authors evaluated the resulting hydropower output across three inflow conditions representing wet, normal, and dry years, demonstrating the model's robustness in managing multi-purpose reservoir operation under hydrologic variability.

2.5.3 Ethiopian Dams Case Studies: Arjo Dedessa and Ribb Irrigation Dam

Recent investigations into Ethiopian multi-purpose dams, specifically the Arjo Dedessa and Ribb Irrigation Dams, highlight both the promising hydropower potential of these sites and the significant technical gaps that limit their practical exploitation (Kishe, 2023; Bezabih, 2021). While both studies demonstrate that these dams could contribute meaningfully to Ethiopia’s renewable energy landscape, they differ in focus and methodological approach, offering complementary insights.

Kishe (2023) examined the Arjo Dedessa Dam using advanced optimization techniques implemented through LINGO software. The study explored two retrofitting scenarios, aiming to maximize annual energy generation while maintaining essential irrigation, ecological, and reservoir constraints. By optimizing operational strategies and leveraging flood storage to increase live capacity, the research identified a peak potential of 6.51–6.75 MW. The study emphasizes the technical suitability of Arjo Dedessa for hydroelectric generation but does not extend into detailed engineering design or the integration of new infrastructure such as penstocks and powerhouse facilities, leaving a gap between theoretical potential and practical application.

In contrast, Bezabih (2021) focused on the Ribb Dam and the feasibility of a Small Hydroelectric Power (SHP) installation. The study applied flow duration curve analysis to determine an optimal nominal power output of 5.53 MW, using a smooth head of 70.37 m and an average flow of 14.63 m^3/s. While the research supports SHP as a low-cost, renewable energy option for rural Ethiopia, it relies on assumed head losses rather than site-specific calculations and does not include detailed equipment selection, site layout, or financial assessment such as NPV or LCOE.

Comparing the two studies reveals a consistent and critical limitation: both confirm the theoretical hydrological potential but stop short of addressing engineering feasibility and financial viability. For Arjo Dedessa, the gap lies in the lack of detailed site layout and structural modification plans; for Ribb Dam, it is the absence of precise technical design and economic evaluation.

2.6 Conceptual Framework

The conceptual framework for this study illustrates the logical flow of analysis used to evaluate the technical, operational, and economic feasibility of hydropower retrofitting at Tendaho Dam. It organizes the three methodological phases into a clear sequence that begins with system characterization, progresses through engineering modelling, and concludes with financial evaluation. The framework aligns directly with the study objectives and shows how data and analytical outputs move from one phase to the next to support the final feasibility decision.

The conceptual framework presents a sequential structure that links hydrological, structural, and operational assessments with engineering modelling and economic evaluation. Phase I forms the foundation by analyzing water availability, reservoir levels, outlet geometry, and irrigation release requirements. These inputs provide essential engineering parameters such as dependable flow, net head, and structural constraints (see Fig 2.2). Phase II uses this information to conduct technical feasibility modelling. In this phase, the three retrofit alternatives, the dedicated waterway option, bifurcated tunnel option, and riparian release option are evaluated based on turbine suitability, hydraulic losses, power generation, and energy output.

As Fig 2.2 depicts, Phase III then applies financial modelling using indicators such as Net Present Value, Levelized Cost of Energy, and payback period. These evaluations determine whether each technically feasible retrofit alternative is also economically competitive compared to national and international small hydropower benchmarks.

The flow of information across the phases ensures that technical and economic decisions are based on verified hydrological and structural realities. The final output is a clear decision on whether hydropower retrofitting at Tendaho Dam is feasible without compromising irrigation deliveries.

This study seeks to bridge this gap by conducting thorough site investigations, preliminary engineering designs, and financial analyses. By doing so, it aims to transform the identified hydropower potential of these high-capacity Ethiopian dams into practical, implementable, and economically viable energy solutions.

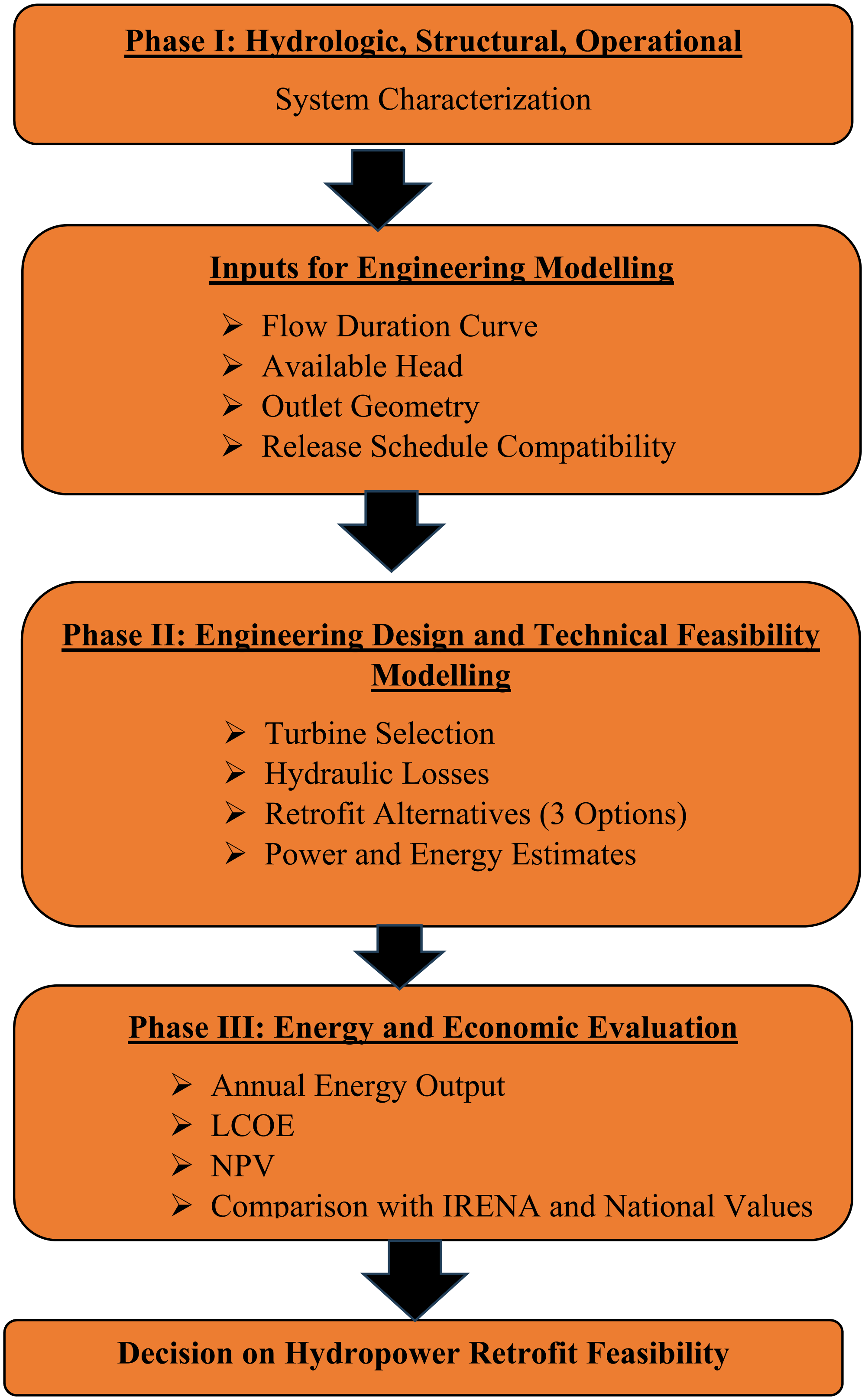


Figure 2.1 Conceptual framework (Source: Own conceptual framework)

CHAPTER THREE

METHODOLOGY

3.1 Introduction

This chapter presents the methodological framework that guided the assessment of the technical, operational, and economic feasibility of retrofitting the Tendaho Dam for hydropower generation. The methodology follows a structured three phase approach that reflects the sequence of tasks required to determine whether hydropower can be integrated into the existing irrigation based system without disturbing its primary function. Tendaho Dam was designed to deliver large scale irrigation water to the downstream command areas in the lower Awash Basin. Hydropower therefore cannot be evaluated independently from irrigation, since any modification of flow patterns may affect agricultural water supply. For this reason, the methodology follows a sequential structure that begins with understanding the existing hydrological, structural, and operational conditions of the dam. This is defined as Phase I: Hydrological, Structural, and Operational System Characterization. It provides the necessary inputs for the engineering modelling carried out in Phase II: Engineering Design and Technical Feasibility, where available head, flow, turbine suitability, hydraulic losses, and structural compatibility are evaluated in detail. In this phase, the engineering implications of the three retrofit options are assessed. These assessments rely on the physical dimensions of the structures, the hydraulic constraints of the outlets, and the irrigation release rules that govern the operation of the dam.

The results from Phase I to Phase III: Energy Modelling and Economic Analysis, which evaluates the financial performance of each retrofit alternative using annual energy output, cost parameters, and economic indicators such as Net Present Value and Levelized Cost of Energy. RETScreen was used for this purpose because it applies internationally recognized clean energy evaluation standards.

3.2 Research Design

The research design follows a sequential, quantitative, engineering based approach grounded in hydrological analysis, structural interpretation, hydraulic modelling, and economic evaluation. The design is quantitative because all the variables required to evaluate hydropower feasibility, such as discharge, head, conduit dimensions, turbine efficiency, annual energy, and economic cost indicators, are numerical and can be analyzed using engineering formulas and financial models. Such quantitative engineering designs are commonly used in hydropower retrofit studies.

Phase I focuses on understanding the baseline characteristics of the Tendaho Dam system. Hydrological datasets such as inflow records, reservoir levels, and irrigation releases are analyzed to determine the flow availability for energy generation. Structural and operational assessment in Phase I identifies physical constraints and functional priorities.

Phase II uses engineering design principles to evaluate technical feasibility. In this phase, head availability, flow conveyance, turbine suitability, penstock design, and hydraulic losses are assessed using established hydropower engineering methods.

Phase III applies economic and financial modelling to determine whether the technically feasible options are financially viable. This phase relies on energy estimates from Phase II and evaluates cost effectiveness using Net Present Value, Levelized Cost of Energy, and payback period through the RETScreen platform.

3.3 Study Site

The study site is the Tendaho Dam, located on the Awash River in the Afar Region of Ethiopia. It is the largest dam in the Awash Basin, constructed primarily for large-scale irrigation development (Ethiopian Ministry of Water Resources [MoWR], 2005). The dam is a zoned earth-fill embankment with a crest elevation of 413.5 meters above sea level (m.a.s.l.), creating a reservoir with a gross storage capacity of approximately 1.9 billion cubic meters (BCM) at a Full Supply Level (FSL) of 408 m.a.s.l. (MoWR, 2005). The existing hydraulic infrastructure includes a gated spillway and a converted diversion tunnel (6 m diameter) that serves as the sole irrigation outlet, conveying water to a canal system designed to irrigate 60,000 hectares of sugarcane plantation (WWDSE & WAPCOS, 2005).

The site’s hydrology is defined by the Awash River, whose flow has been extensively studied since the 1960s. Historical assessments indicate a mean annual flow at the dam site ranging between 1,690 and 2,820 million cubic meters per year, subject to significant losses from upstream irrigation and the Gedebessa swamp system (Halcrow, 1989; Sogreah, 1965). The dam’s geographical setting within the tectonically active Afar Depression also presents specific seismic design considerations (Ayele, 2016). This site was selected as a critical case study because it embodies the national challenge of underutilized, single-purpose water infrastructure with demonstrable yet untapped hydropower potential, aligning with recent research advocating for the retrofitting of non-powered dams (NPDs) for energy generation (Hadish et al., 2023).

3.4 Sources of Data

The study relied on multiple sources of data to ensure that the assessment of hydropower retrofitting at Tendaho Dam was grounded in accurate and comprehensive information. The primary sources of data were official government institutions, professional engineering organizations, and direct field observations. Hydrological data were mainly obtained from the Ministry of Water and Energy, which operates the long-term monitoring network in the Awash Basin. These records include river discharge measurements, rainfall data, reservoir levels, and climatic variables collected over several decades. Because these datasets follow national standards, they provide a dependable foundation for understanding flow behavior and long-term water availability.

Structural and design-related data were collected from engineering documents prepared by WWDSE and WAPCOS, the institutions responsible for the original design and implementation studies of the Tendaho Dam. These documents contain detailed technical specifications such as tunnel dimensions, intake structure geometry, reservoir elevations, and operational rules. Since these materials represent the official design history of the project, they are essential for modelling hydraulic performance, estimating available head, and evaluating structural compatibility for retrofitting.

In addition to secondary documents, primary data were gathered through site visits and direct observations. The field survey allowed verification of the current condition of the dam, including the state of the intake tower, irrigation outlet structures, regulators, and downstream channels. These observations helped confirm whether the existing structures still match the original design assumptions or if any deviations must be considered in the analysis.

The study therefore utilized a combination of quantitative and qualitative data. Quantitative data included discharge measurements, elevation profiles, hydraulic dimensions, and climatic statistics. Qualitative data came from visual inspections, discussions with resident engineers, and contextual notes about operational challenges. By integrating these different types and sources of data, the study ensured a holistic understanding of the physical, hydrological, and operational environment of Tendaho Dam, which is necessary for a reliable hydropower feasibility assessment.

3.5 Data Collection

The study used a combination of structured, document-based, and field-oriented data collection methods to gather the information needed for assessing the hydropower retrofit potential at Tendaho Dam. The first method involved reviewing secondary data from official institutions. Long-term hydrological records; such as river discharge, rainfall, and reservoir water levels were collected from the Ministry of Water and Energy. These records were obtained through direct request and represent standardized national datasets. Their systematic nature made them suitable for constructing Flow Duration Curves and examining seasonal water availability.

A second method focused on collecting engineering and structural data from technical documents prepared by WWDSE and WAPCOS. These documents provided authoritative details about the dam's design, including elevation profiles, intake structures, tunnel dimensions, and operational guidelines. This document review method allowed the study to extract accurate physical measurements required for hydraulic modelling and turbine evaluation.

Field observation formed the third major method of data collection. A site visit was carried out to observe the present condition of the dam structures, confirm accessibility, and verify the accuracy of the design information. This survey was performed from November 1st and 2nd, 2025, in collaboration with the resident engineer and assigned Tendaho Hydropower project professional. During this survey exercise, the researcher able to assess the existing dam and the viability of all three implementation scenarios (Options I, II, and III). The field activities also encompassed inspecting the Tendaho River and the associated irrigation systems. The visit concluded with essential technical discussions concerning the general and existing project conditions.

Figure 3.1 Field observation

During the visit, notes and photographs were taken to document the condition of the intake tower, canals, regulators, and downstream channels. Informal conversations with on-site staff helped clarify operational practices and current challenges.

Finally, financial data were collected through reviewing national power tariff reports, project cost references, and published energy planning documents. Combining these methods provided a balanced mixture of quantitative and qualitative information, ensuring that the study was grounded in both documented evidence and real-world observations.

3.6 Data Collection Procedures/ Phases

The study employed a phased data collection approach, allowing each stage of the analysis to draw from specific sources and types of data that matched its technical purpose. This ensured that the hydrological, engineering, and financial evaluations were grounded in evidence that reflected both the long-term behavior of the Awash Basin and the actual physical conditions at Tendaho Dam.

In Phase I (Data Acquisition and System Characterization), the study relied heavily on hydrological and climatic information obtained from the Ministry of Water and Energy. These data included long-term river discharge records, rainfall observations, reservoir level histories, and flow measurements from gauging stations established since the Sogreah-FAO survey. Such quantitative records formed the basis for constructing Flow Duration Curves, estimating dependable flows, and understanding seasonal water availability. Topographical and elevation data were collected from original mapping documents and cross-verified with field inspections. The field visit also produced qualitative observations regarding sedimentation, spillway conditions, intake structure status, and irrigation releases. Together, these datasets created a clear picture of the natural and operational water regime at the dam site.

Phase II (Engineering and Hydraulic Modelling) required more detailed structural, geometric, and hydraulic data. Most of these were drawn from the official engineering documents produced by WWDSE and WAPCOS during the design and implementation stages. These documents provided authoritative measurements of the reservoir operating levels, tunnel diameters, intake tower configurations, regulator dimensions, and construction materials. Quantitative data such as conduit dimensions, friction values, and elevation differences were essential for calculating gross head, hydraulic losses, and net head. Additional qualitative data were gathered during the site assessment, including the physical condition of concrete linings, accessibility of mechanical elements, and practical constraints on powerhouse siting. This phase translated both measured and observed information into technical modelling inputs.

Phase III (Economic and Financial Analysis) required data of a different nature. Technical outputs from the first two phases: such as expected energy production, flow availability, turbine efficiency, and head values; were used as inputs for RETScreen modelling. Financial data came from national electricity tariff schedules, estimated capital costs drawn from engineering Bill of Quantities, and operation and maintenance assumptions based on industry norms. These were mainly secondary data from government energy reports and international hydropower cost references.

The resulting dataset combined quantitative financial figures with qualitative judgements about operational feasibility, risk, and long-term sustainability. By integrating official records, engineering documents, and field-based observations across all three phases, the study ensured that each analytical step was supported by relevant and credible data.

3.7 Reliability and Validity of Data

The reliability of the data used in this study was strengthened by relying on official and well-established sources. Hydrological records were obtained from the Ministry of Water and Energy, which manages the long-term monitoring network of the Awash Basin. These datasets have been collected using standardized national procedures, making them consistent and dependable for flow analysis. Structural and design information was taken directly from the original engineering documents prepared by WWDSE and WAPCOS during the dam’s planning and construction stages. Because these documents form the authoritative reference for Tendaho Dam's dimensions, materials, and hydraulic structures, they provide a reliable foundation for technical interpretation. In addition, field visits and direct observations were used to verify that the current physical conditions match the documented specifications, further supporting internal consistency.

Validity was ensured through the use of internationally accepted methods and modelling tools. Hydrological assessment followed standard practices such as Flow Duration Curve analysis and seasonal flow evaluation. Engineering calculations, including head-loss estimation and power computation, were performed using well-recognized formulas drawn from hydraulic principles. The economic analysis employed RETScreen, a globally validated software widely used for renewable-energy feasibility studies. By combining verified data sources with established analytical techniques, the study maintains strong methodological validity and supports credible conclusions.

3.8 Methods of Data Analysis

The data analysis for this study followed a structured, progressive approach that connected raw hydrological information with engineering interpretation and finally with economic evaluation. This approach ensured that each phase of the analysis responded to the real conditions of the Tendaho Dam and supported practical decision-making for hydropower retrofitting.

Phase I focused on hydrologic analysis, where long-term flow data were examined to understand the behavior of the Awash River at the dam site. Flow Duration Curves (FDCs) were prepared by ranking daily and monthly discharges and calculating their exceedance probabilities. This helped identify the dependable flow levels, such as Q30 or Q95, which are important for selecting a design flow that balances energy production with system reliability. Seasonal flow patterns were also studied to understand how water availability changes throughout the year and how these variations could influence generation potential.

Phase II addressed engineering and hydraulic modelling. Gross head, topographic elevations, and structural constraints were used to calculate the available net head through the relationship

$$H_n = H_g - (h_f + h_m).$$

Hydraulic losses were estimated using established principles such as the Darcy–Weisbach equation. Power output was calculated through following formula which, each retrofit option to be compared in terms of its technical output.

$$P = \rho\, g\, Q\, H_n\, \eta,$$

Turbine selection was performed by matching head and flow values with internationally recognized turbine operating ranges, ensuring that the chosen machines fit the site's physical and hydraulic realities.

Energy modelling, carried out across Phases II and III, estimated annual energy generation by combining expected operating hours with the seasonal flow variations derived from the FDC. This helped form a realistic picture of long-term performance.

Economic and financial evaluation in Phase III used RETScreen to compute key viability indicators such as LCOE and NPV:

$$LCOE = (C_t + O\&M + Replacements - Salvage) / E_t$$

$$NPV = \Sigma\, (R_t - C_t) / (1 + r)^t.$$

Together, these methods provided a complete analytical pathway from water availability to engineering feasibility and financial justification and operational aspects of the hydropower system.

3.9 Ethical Considerations

Ethical considerations were integrated throughout the study to ensure responsible use of information and respect for the institutions involved. All hydrological and structural data were obtained through formal channels from government agencies and engineering organizations. These sources were acknowledged properly, and the data were used only for academic purposes, in line with institutional expectations. Care was taken not to alter or manipulate official records; instead, the analysis was based on the original values to maintain integrity and transparency.

During field observations at Tendaho Dam, attention was given to respect site regulations and follow safety guidelines provided by local staff. No activities were conducted that could disrupt dam operations or interfere with workers performing their duties. Informal discussions with technical staff were used only to clarify operational conditions, and their insights were treated confidentially. The study avoided collecting any personal data and focused strictly on technical, environmental,

CHAPTER FOUR

SALIENT FEATURES OF THE EXISTING TENDAHO HEADWORK STRUCTURES

4. 1 Introduction

The Tendaho Dam constitutes the central element of the Tendaho Dam & Irrigation Project, engineered to control the flow of the Awash River primarily for the extensive irrigation of around 60,000 hectares, largely for sugar cane cultivation. Its situation within the seismically active Afar Region demanded specific design adaptations to guarantee long-term stability and operational safety (WWDSE & WAPCOS, 2005).

4.2 Tendaho Dam Main Structure

The primary dam is a zoned earth-fill embankment, a type selected because the foundation conditions, composed of alluvial deposits overlying less competent sedimentary rock, were not ideal for a heavier concrete structure. Its design incorporates an impervious central clay core that acts as the fundamental seal against water seepage. Constructed along a straight axis for surveying and building efficiency, the embankment's upstream face is armored with durable dumped rock riprap, which is underlain by a robust fifty-centimeter filter blanket. The structure crest is positioned at an elevation of 413.5 meters and maintains a consistent width of ten meters (WWDSE & WAPCOS, 2005). To ensure safety and control seepage, foundation treatment includes a deep grout curtain installed directly beneath the core. Furthermore, the design integrates protective measures such as a downstream fine filter layer, which is crucial for preventing internal soil erosion and for mitigating risks related to potential core damage during seismic activity.

4.3 Spillway

Functioning as the essential safety outlet to prevent overtopping during flood events, the spillway is a chute type located on the left bank ridge. This strategic placement takes advantage of a natural saddle in the topography and avoids interference with the nearby main irrigation canal off-take, which is also situated on the left bank. Flow is governed by an ogee crest weir. The spillway possesses a substantial discharge capacity, divided into three distinct bays, each providing a clear width of 10.5 meters. The bed of the approach channel leading to this weir is set at Elevation 396.0 meters (WWDSE & WAPCOS, 2005).

4.4 Dam and Reservoir Salient Features

The design of the dam and its accompanying reservoir is defined by several key elevation levels, constrained by the local terrain. The natural topography limits the maximum height of the embankment, resulting in a crest elevation of 413.5 meters, with a corresponding required Top Bank Level at or above 413.3 meters (WWDSE & WAPCOS, 2005). The reservoir's maximum operating level, or Full Reservoir Level (FRL), is established at Elevation 408.0 meters. The lowest operational level, or Minimum Drawdown Level (MDDL), is set at Elevation 396.0 meters. The live storage, representing the usable water volume between the FRL and MDDL, is estimated at 1,174 million cubic meters.

4.5 Irrigation Outlet and Tunnel Conduit

The permanent system for releasing irrigation water was developed by repurposing one of the original river diversion tunnels used during the dam's construction phase. This conduit functions as the principal irrigation outlet, enabling the controlled release of water for agricultural supply, managed reservoir filling, and emergency depletion. The flow within this system is regulated by a head regulator and a cross regulator, both situated near the tunnel’s downstream exit. The tunnel itself is a horseshoe-shaped conduit with a diameter of 6.0 meters, lined with concrete and designed to efficiently convey high-velocity flows up to 10.65 meters per second. The lining thickness is typically 50 centimeters but is reinforced to 80 centimeters near the portal areas to withstand greater external pressures from the surrounding rock.

4.6 Intake Structure

The intake structure is positioned at a carefully determined elevation to ensure its functionality is not compromised by reservoir sedimentation over the project's lifespan, while its center line remains sufficiently below the Minimum Drawdown Level to ensure smooth water abstraction. This structure served a dual purpose: initially facilitating flood diversion during construction via bottom outlets, and now operating as the primary intake for irrigation through four gate-controlled openings at the 393-meter level. An auxiliary irrigation sluice, measuring 1.5 by 1.5 meters at elevation 374 meters, is also available for reservoir evacuation if required. The intake tower rises 50.3 meters from its base and features a substantial rectangular base, a control house, and a circular superstructure housing gate operating machinery (WWDSE & WAPCOS, 2005). Key components include the four irrigation openings, the bell-mouth entry to the 6-meter diversion tunnel at elevation 373.5 meters, and the connecting irrigation sluice. The base is founded on mass concrete resting on rock, with a specialized concrete cushion to dissipate the energy of falling water. Access is provided via a footbridge linking the tower to the left-bank access road at the dam crest elevation.

4.7 Outlet Flow Regulation

Precise management of water discharged from the tunnel is accomplished by a regulator system located immediately downstream before the flow enters the main canal network. The head regulator, positioned at the canal's inception, performs the critical roles of controlling inflow volume, dissipating the energy of the high-velocity water, and preventing sediment and debris from entering the irrigation system. Immediately adjacent, the cross regulator provides necessary downstream control by managing tailwater levels, raising the forebay elevation when the main canal level is low, and providing a route to safely discharge surplus water back into the Awash River.

Table 4.1 Salient Features

Salient Features	**Head Regulator**	**Cross Regulator**
Discharge	78 m^3/s	365.3 m^3/s
FSL (Full Supply Level)	378.5 m	378.5 m
Flow depth	5.5 m	5.5 m
Bed Width	30 m	30 m

Source: (WWDSE & WAPCOS, 2005).

4.8 Main Canal

According to WWDSE & WAPCOS, (2005) the main Canal is designed to transport water over a long distance with the following maximum capacity and construction parameters:

Main Canal Length: 72 km

Maximum Discharge Capacity: 78 m^3/s

Maximum Bed Width: 22.50 m

CHAPTER FIVE

HYDROLOGY

5.1. Introduction

The Awash Basin, which covers an area of about 112,211 km², drains the northern segment of the Rift Valley and originates at elevations close to 2,500 meters (MoWR, 2005). The upper basin flow is heavily influenced by the Koka Reservoir, operational since 1960 and by the subsequent hydropower developments at Koka and Awash II/III. In addition, irrigation withdrawals upstream significantly reduce the discharge measured near the Awash Station.

A major hydrological challenge relevant to the Tendaho project is the Gedebessa swamp system. Although sizeable tributaries from the western highlands, such as the Kesem and Mille rivers, contribute an estimated 900 Mm³ of runoff each year, the swamp complex causes substantial water losses ranging from roughly 400 Mm³ to 1,200 Mm³ annually (Halcrow, 1989). According to Halcrow (1989), these losses are clearly reflected in the mean annual flow volumes: i.e. Hertale upstream swamp and downstream were 2,692 Mm³ and 2,424 Mm³ respectively.

This reduction illustrates the scale of hydrological depletion that must be incorporated into the water balance of the Tendaho Dam. The lower basin is also characterized by two flood peaks, one in spring and another in summer, which shape the seasonal flow regime essential for irrigation planning and hydropower evaluations.

5.2 10-Day Reservoir Simulation Model

A ten-day water-balance model prepared by WWDSE & WAPCOS (2005) was employed to estimate the probability of meeting the gross ten-day irrigation requirements (as presented in Table 5.4), while also maintaining a constant environmental release of 5 m³/s and accounting for evaporation losses from the reservoir surface. Seepage losses were assumed to be negligible for the initial assessment; any small leakage that does occur is expected to contribute to downstream ecological flows. The simulation was carried out for three stages of the reservoir's projected lifespan: the initial condition at year zero, the mid-point of the design life at year twenty-five, and the end of the design life at year fifty. In this context, the term “design life” refers to the period during which the reservoir can reliably sustain irrigation with a success rate exceeding 75 percent.

Figure 5.1 10-day reservoir evaporation and gross irrigation releases data used in simulation

10-day		Reservoir Evaporation (mm)	Scenario I, 60000 ha, Irrigation demand (MMC/10 day)	Scenario II, 48000 ha, Irrigation demand (MMC/10 day)
Jan	1	60	29.7	23.7
	2	60	31.7	25.4
	3	60	33.8	27.1
Feb	4	58	31.5	25.2
	5	58	32.1	25.7
	6	58	33.5	26.8
Mar	7	84	34.9	27.9
	8	84	35.6	28.5
	9	84	34.8	27.8
Apr	10	78	33.4	26.7
	11	78	33.8	27.0
	12	78	41.1	32.8
May	13	85	59.0	47.2
	14	85	64.4	51.5
	15	85	72.9	58.3
Jun	16	88	67.3	53.8
	17	88	68.0	54.4
	18	88	68.1	54.5
Jul	19	92	63.3	50.6
	20	92	59.3	47.4
	21	92	64.0	51.2
Aug	22	81	62.2	49.7
	23	81	64.4	51.5
	24	81	63.3	50.6
Sep	25	80	61.0	48.8
	26	80	58.7	47.0
	27	80	61.8	49.4
Oct	28	73	53.5	42.8
	29	73	50.3	40.3
	30	73	47.0	37.6
Nov	31	93	44.2	35.4
	32	93	45.4	36.3
	33	93	46.4	37.1
Dec	34	94	39.0	31.2
	35	94	39.6	31.7
	36	94	39.5	31.6
Annual		2899	1769	1415

Source: WWDSE & WAPCOS (2005)

5.3 Flow Duration of Curve

The flow duration data and the resulting Flow Duration Curve were generated by utilizing the reservoir operation rule data are presented in Table 5.5 and Figure 5.5 respectively. This operation data, which was prepared in the previous WWDSE study, serves as the representative stream flow input for our hydropower study which was initially defined with irrigation demand (WWDSE & WAPCOS, 2005).

Table 5.1 Flow and level of excedence

Flow im m3/s	**Level of Exceedence**
81.00	0%
80.14	5%
78.77	10%
75.33	15%
73.47	20%
73.17	25%
73.05	30%
71.21	35%
69.17	40%
66.72	45%
56.94	50%
53.54	55%
52.08	60%
51.95	65%
45.56	70%
40.69	75%
39.94	80%
38.86	85%
37.96	90%
37.36	95%
35.40	100%

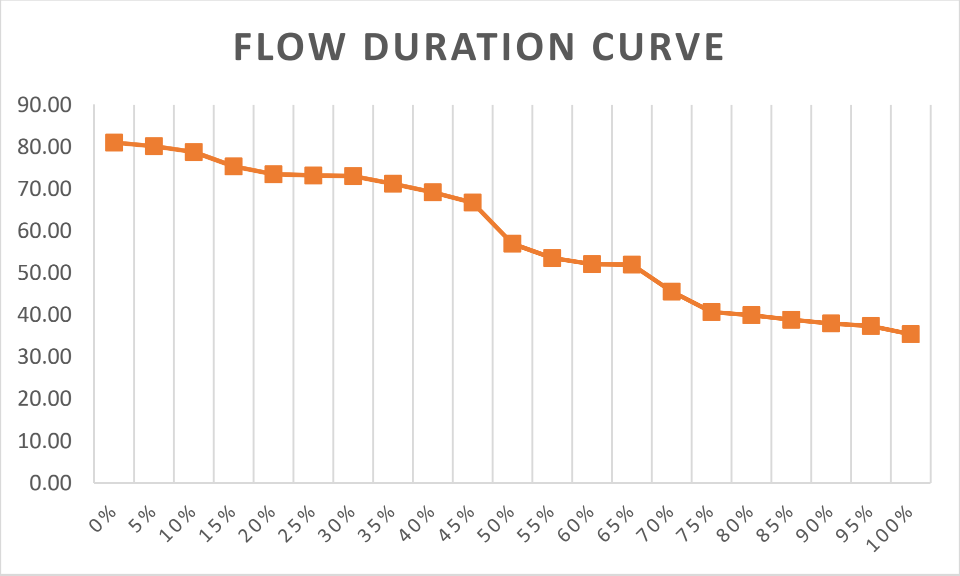


Figure 5.1 Flow Duration Curve graph

CHAPTER SIX

MODELING AND SELECTION OF SMALL-HYDRO COMPONENTS

6.1 Introduction

This chapter brings together the final design decisions for the central components of the small hydropower scheme. It outlines the specifications for the penstock, the turbine and generator arrangement, while also defining the civil works required to support the overall system. The intention is to present an integrated design framework in which each element complements the hydraulic, mechanical, and structural demands of the site.

6.2 Flow Diversion Mechanism and Major Component Modelling

The first step in the project involves developing the hydraulic and structural systems needed to guide water from the Tendaho head work into a stable and controllable flow suited for power generation. This stage sets the foundation for all later design choices, because the success of the diversion mechanism directly influences both performance and financial analysis In each of the three design alternatives, the primary challenge lies in striking the right balance between limiting the scale and cost of civil works and ensuring that the electromechanical system remains efficient, manageable, and consistent during operation.

6.2.1. Option I: The Dedicated Waterway Strategy (Maximum Isolation)

The first option pursues a fully independent hydraulic route reserved exclusively for power production, thereby removing any possibility of conflict with ongoing irrigation tunnel/operation. The design philosophy centers on isolating the hydropower system and providing it with its own head-utilization path. Achieving this configuration requires a major civil intervention: a new tunnel approximately 247m long and 6 m in diameter must be excavated through the abutment so that the powerhouse can be positioned at the base of the mountainside, physically detached from existing irrigation tunnel Electromechanical features include a specific valve installed at the outlet of the current irrigation tunnel. Water is then conveyed through the new penstock to two Kaplan turbine-generator units. This solution reduces hydraulic complications where the systems connect, but it does so at the expense of extensive underground construction.

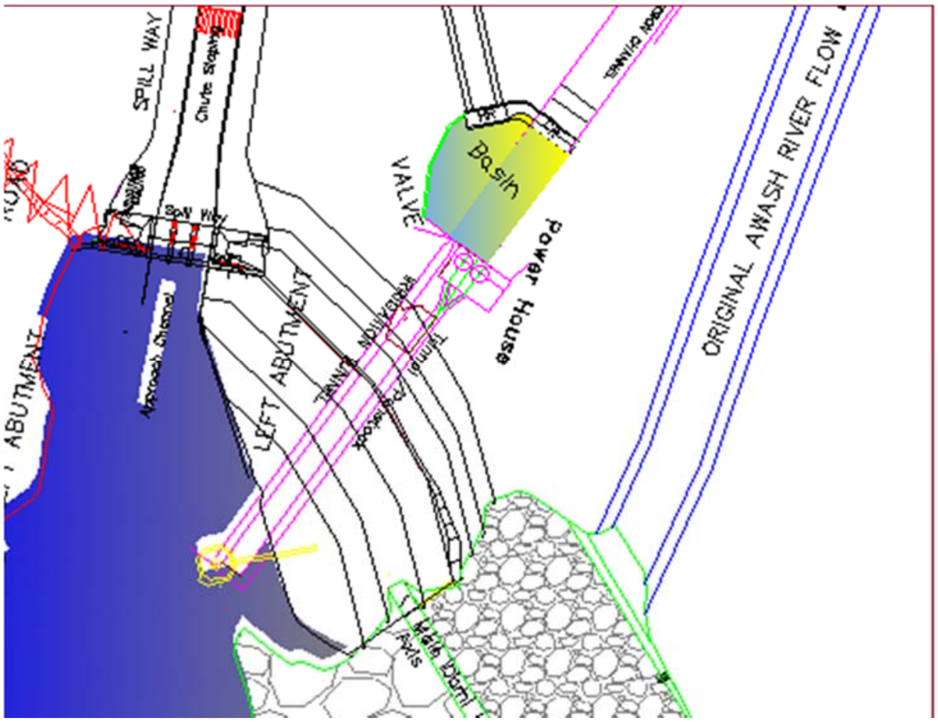


Figure 6.1 a-Option I Layout arrangement of Independent proposed tunnel/penstock and Location of Power House

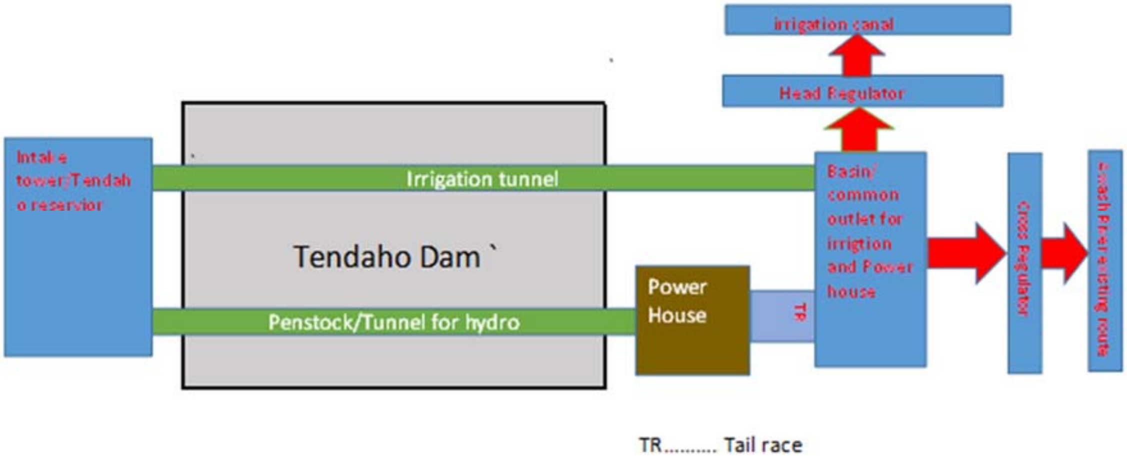


Figure 6.2 Option I Schematic

6.2.2 Option II: The Bifurcation Strategy (Integrated Flow Management)

The second option takes an integrative approach by linking the hydropower intake directly downstream of the existing irrigation release point. Here, the emphasis is on coordinating flows and enabling sequential use, while ensuring that the irrigation demand remains fully protected. Implementing this strategy requires the removal and excavation of about t60 meters of the existing concrete tunnel to establish a bifurcation zone where the original conduit divides into two steel penstocks. Although some excavation into the abutment is still necessary, it is limited mainly to accommodating the powerhouse and the shorter penstock. The principal hydraulic task is managing two adjacent dedicated to irrigation and the other to hydropower. An isolation valve located at the powerhouse allows hydropower maintenance activities without affecting irrigation releases, and a three-meter butterfly valve regulates irrigation flow after a diameter reduction. Compared with the first option, this arrangement depends on a much shorter penstock of roughly 47 m to supply the two Kaplan turbine-generator units.

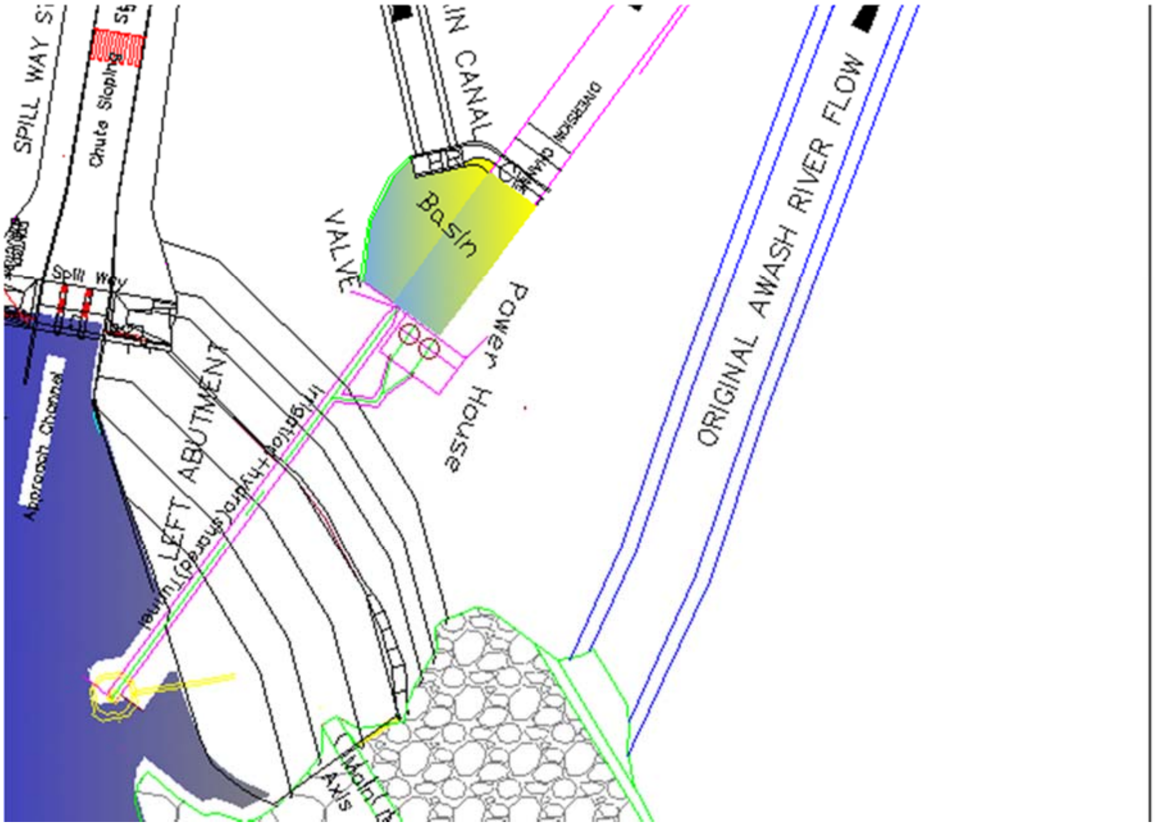


Figure 6.3 Option II Layout arrangement of shared penstock with irrigation tunnel for power generation and Location of Power House

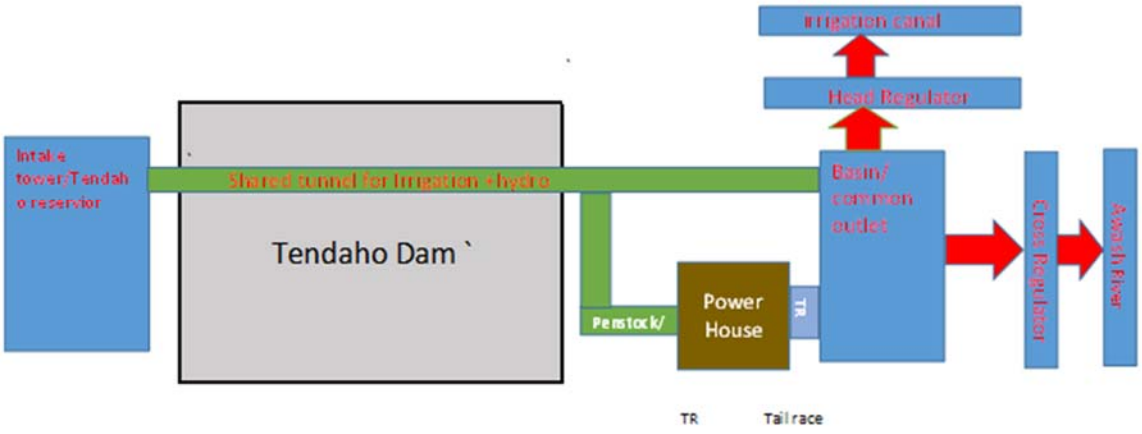


Figure 6.4 Option II Schematic

Operation Philosophy for irrigation and hydropower scenario for option I and II

The operational philosophy for a multi-purpose water project must balance two often-competing demands: the seasonal, volumetric needs of agriculture and the instantaneous, grid-dependent demands of power generation, as shown in below table

Core Principle: The reservoir is managed primarily as a seasonal storage tool to guarantee food security. Power generation is treated as a secondary "by-product" of irrigation release

Scenario	Hydropower Line	Irrigation Bypass	Result
Standard Operation	**Open** (Generating)	**Closed**	Power is produced; discharge meets 100% of irrigation needs.
Peak Irrigation	**Open** (Generating)	**Partially Open**	Max flow exceeds turbine capacity; bypass covers the deficit.
Hydro Maintenance	**Closed** (MIV shut)	**Open/close**	Irrigation continues uninterrupted via the original pipe.
Partial Hydro Load	**Throttled**	**Partially Open**	The bypass valve compensates to ensure constant canal levels.

Table 6.1 Irrigation and Hydro operation scenario

6.2.3 Option III: The Channel Utilization Strategy

The third option adopts a more flexible, low-head configuration by making direct use of the flow already available in the open channel, rather than relying on the higher-pressure head and long penstock required in the previous alternatives. This design places a premium on simplicity, modular construction, and the ability to deploy equipment relatively quickly. Its civil works are concentrated almost entirely on refurbishing the existing channel, including the formation of an integrated intake arrangement within the channel itself, which guides water efficiently toward the turbine modules. Because the design does not depend on tunnels or major structural changes near the dam, the civil footprint is considerably reduced. On the electromechanical side, the scheme employs one S type Kaplan turbine units, selected because their hydraulic characteristics match the behavior of open-channel flow. The control room will undergo full refurbishment and automation so that intake regulation and generation processes for the modular units can be managed with improved precision and reduced operator workload.

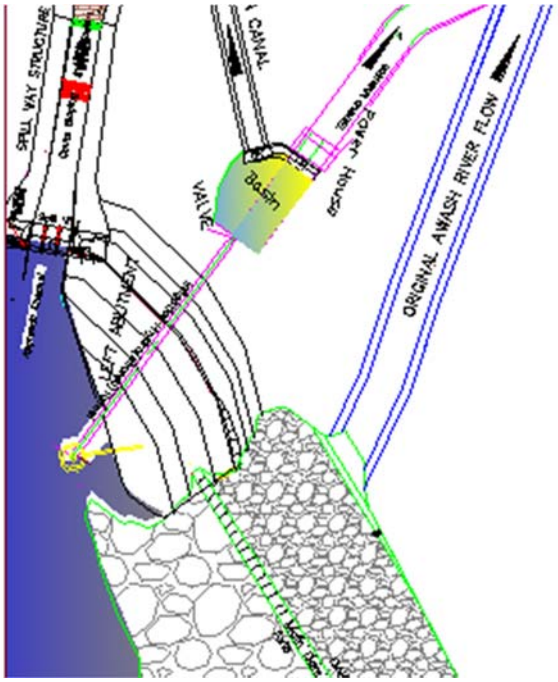


Figure 6.5 Option III Layout arrangement of Power House at cross regulator without connection reservoir head and without penstock

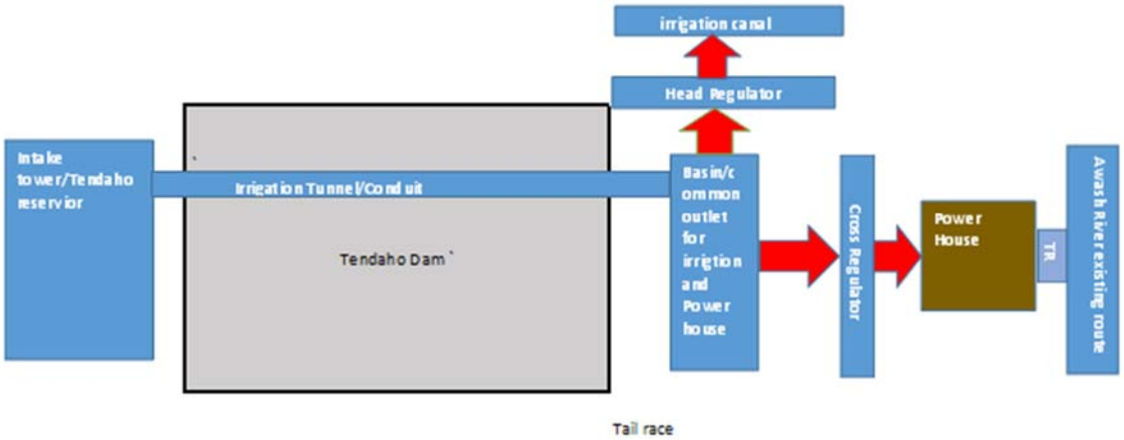


Figure 6.6 Option III schematic

Penstock Design

The penstock is the critical, closed pipeline responsible for safely conveying water under pressure from the intake structure to the turbine. The design analysis of the penstock requires detailed calculations of its key physical characteristics (e.g., material, dimensions) and hydraulic characteristics (e.g., head loss, flow velocity).

6.2.4 Option I: Diameter of the Penstock

Calculation of the optimal diameter to minimize friction losses while remaining economically feasible. As per USBR empirical formula
The recommended velocity V can be calculated

$$V = 0.125 \times (2gH)^{0.5}$$

Taking
H = Elevation at reservoir –FSL at tail water level regulators

$$H = 408-378.5 = \underline{29.5m}$$

Therefor

$$V = 0.125 \times (2gH)^{0.5} = 0.125*(2*9.81*29.5)^{0.5} = \underline{3m/s}$$

Then diameter of the penstock D can be calculated

$$D = (4Q/\Pi V)^{0.5}$$

Where Q= 73m3/s at 30% flow dependence taken with assumption the system connected to grid

$$D = (4*68.7/3.14*3)^{0.5} = \underline{5.66m}$$

Therefore, we can consider 6m penstock because the same history with irrigation pipe.

6.2.5 Option II: Bifurcation of tunnel to the penstock Diameter

The principle of "equal loss" in a symmetrical bifurcation (where the flow and configuration in the two branch pipes are identical) is used to find the minimum diameter that satisfies a specific hydraulic requirement, often related to maximizing net head or minimizing cost.

Here is the step-by-step analysis and the required formula, using the universally accepted Darcy-Weisbach equation for frictional head loss.

- ***The Principle of Equal Frictional Loss***

When a main pipe of diameter D is bifurcated into n branch pipes (in your case, n=2) to maintain a constant level of friction loss (hf) across the system, the relationship between the diameters can be derived by equating the Darcy-Weisbach formula for the main pipe and the sum of the head losses in the branch pipes.

For a symmetrical bifurcation (equal flow Q_n and equal loss $h_{f,n}$ in both branches, and equal length L and friction factor f assumed), the total discharge is $Q_0 = n .Q_n$ The condition is:

Head Loss in Main Pipe = Head Loss in Branch Pipe

$$h_{f,0} = h_{f,n}$$

- *Applying the Darcy-Weisbach Equation*

The head loss due to friction (hf) in a pipe is given by the Darcy-Weisbach equation:

$h_f = f .L/D .V^2/2g$ …………………………… (Darcy-Weisbach, 1845)

Where:

h_f: Head loss due to friction (m)

f: Darcy friction factor (dimensionless, a function of Reynolds number and pipe roughness)

L: Pipe length (m)

D: Pipe diameter (m)

V: Mean flow velocity (m/s)

g: Acceleration due to gravity (approx. 9.81 m/s^2)

- *Express Velocity in Terms of Flow Rate and Diameter (Continuity Equation)*

To relate the head loss to the diameters, we replace velocity (V) using the continuity equation,

$$Q = A\,.V,\ where\ A = \pi\, D^2/4.$$

$$V = Q/A = Q/\pi\, D^2/4 = 4Q/\pi\, D^2$$

$h_f = f\,.L/D\,.1/2g.\ (4Q/\pi\, D^2)^2$ .... Substituting *V* into the Darcy-Weisbach equation:

$$h_f = (8fL/g.\pi^2).\ Q^2/D^5$$

Since *f, L, g,* and π are constants for a specific section, we can simplify this as:

$$h_f = K\,.Q^2/D^5 \qquad \text{where} \qquad K = 8fL/g.\pi^2$$

- Apply the Equal Loss Condition

We apply the condition $h_{f,\,0} = h_{f,\,n}$ to the main pipe (diameter D_0=6m, flow Q_0) and one of the branch pipes (diameter D_n, flow Q_n). For a simple bifurcation into two equal units (n=2), the flow in each branch is $Q_n = Q_0 / 2$.

Since the pipe material (*f*) and the equivalent length of the sections (*L*) are assumed to be similar:

Cancel the constant K:

$Q_0^2/D_0^5 = Q_n^2/D_n^5$

- *Solve for the Branch Pipe Diameter (D_n)*

Substitute $Q_n = Q_0 / n$.. (Where n=2):

$Q_0^2/D_0^5 = (Q_0/n)\,^2/D_n^5 = (Q_0/2)^2\,/D_n^5$ ……………………….Cancel Q_0^2 from both sides:

$$1/D_0^5 = 1/n^2\,.D_n^5$$

Rearrange the terms to solve for D_n:

$$D_n^5 = D_0^5/n^2$$

$$D_n = D_0\,.(1/n^2)^{1/5}$$

- *Calculate the Required Diameter*

Given:

Main Pipe Diameter, D_0 = 6 m

Number of Branch Pipes, n = 2

$$D_n = 6\ m\,.(1/2^2)^{1/5}\underline{\ = 4.547\ m}$$

- *Implications*

The hydraulic assessment shows that dividing a 6-meter penstock into two separate branches, while keeping the frictional head loss per unit length equal to that of the original conduit- assuming a constant friction factor and an equivalent comparison length, would require each branch to have an approximate diameter of 4.55 meters. This value reflects only the theoretical lower limit needed to maintain hydraulic consistency between the main pipe and its branches when friction alone is considered. In practical hydropower engineering, however, this estimate must be adjusted to incorporate factors that extend beyond the simplified analytical model. One such consideration is the influence of minor losses, particularly those that arise at the bifurcation point where the loss coefficient depends closely on the geometry and branching angle. Structural aspects must also be evaluated, since the branch pipes are required to withstand internal pressures and the resulting thrust forces. In addition, the final selection of pipe diameter is typically guided by an economic optimization process that weighs the increased material and construction costs associated with a larger pipe against the long-term economic penalty of greater head losses and consequently reduced energy revenue that would occur if the diameter were made too small.

6.3 Losses and Net Head Calculation

This section focuses on quantifying all hydraulic energy losses that occur between the intake and the turbine inlet. These losses are subtracted from the gross head to determine the Net Head (H_n) available for power generation, which is a crucial factor in turbine selection and will be demonstrated for Option I and II.

6.3.1 Option I: Head Loss

Here are the detailed calculations using provided parameters:

Static Head: 29.5 m

Penstock Diameter: 6 m

Length of Penstock: 247.36 m

Velocity: 2.58m/s (Calculated Q=73 m^3/s and D=6m)

Acceleration due to gravity (g): 9.81 m^2/s

- ***Assumed Parameters***

Darcy-Weisbach Friction Factor (***f***): 0.03 (a typical value for concrete penstocks) and 0.02 for steel. Sum of Minor Loss Coefficients ($\sum \boldsymbol{K_L}$): 1.05 (a common estimate for inlet, a few bends, and a valve).

1. *Major Head Loss (H_{major})*

This is the friction loss along the length of the penstock, calculated using the Darcy-Weisbach equation:

$$H_{major} = f.L/D.\ V^2/2g = 0.03*\ (247.36\ m/6\ m)*\ 2.58^2/\ (2*9.81) = \underline{0.42m}$$

2. *Minor Head Loss (H_{minor})*

This accounts for losses at fittings (bends, valves, inlet, etc.):

$$H_{minor} = \sum KL*\ V^2/2g = 1.05*2.58^2/\ (2*9.81) = \underline{0.357\ m}$$

3. *Total Head Loss (H_L)*

The total head loss is the sum of major and minor losses:

$$H_L = H_{major} + H_{minor} = 0.42m + 0.357m = \underline{0.777\ m}$$

The Net Head (H_{net}) available to drive a turbine is the static head minus the total head loss:

Where $H_{static}=b408-378.5= \underline{29.5m}$

Therefore

$$H_{net} = H_{static} - HL = 29.5\ m - 0.777m = \underline{28.72\ m}$$

6.3.2 Option II: Head Loss

Here are the detailed calculations using provided parameters, will be considered in main and branch pipe:

I) For Main pipe

Static Head: 29.5 m

Penstock Diameter: 6 m

Length of Penstock: 187 m (247-60)

Velocity: 2.58m/s (Calculated Q=73 m^3/s and D=6m)

Acceleration due to gravity (g): 9.81 m^2/s

Assumed Parameters

Darcy-Weisbach Friction Factor (*f*): 0.03 (a typical value for concrete penstocks)

Sum of Minor Loss Coefficients ($\sum K_L$): 1.05 (a common estimate for inlet, a few bends, and a valve).

1. *Major Head Loss (H_{major})*

This is the friction loss along the length of the penstock, calculated using the Darcy-Weisbach equation:

$$H_{major} = f.L/D.\ V^2/2g = 0.02 * (187\ m/6\ m) * 2.58^2/(2 * 9.81) = \underline{0.318m}$$

2. *Minor Head Loss (H_{minor})*

This accounts for losses at fittings (bends, valves, inlet, etc.):

$$H_{Minor} = \sum KL * V^2/2g = 1.05 * 2.58^2/(2 * 9.81) = \underline{\ 0.357\ m}$$

3. *Total Head Loss (H_L)*

The total head loss is the sum of major and minor losses:

$$H_{Lmailn} = H_{major} + H_{minor} = 0.318m + 0.357m = \underline{0.675\ m}$$

For Branch pipe

Penstock Diameter:4.55 m

Length of Penstock: 47 m

Velocity: 4.49m/s (Calculated Q=73 m3/s and D=4.55m)

Acceleration due to gravity (g): 9.81 m^2/s

Assumed Parameters

Darcy-Weisbach Friction Factor (*f*): 0.02 (a typical value for steel penstocks)

Sum of Minor Loss Coefficients ($\sum K_L$): 1.05 (a common estimate for inlet, a few bends, and a valve).

1. *Major Head Loss (H_{major})*

This is the friction loss along the length of the penstock, calculated using the Darcy-Weisbach equation:

$$H_{major} = f.L/D.\ V^2/2g = 0.02 * (47\ m/6\ m) * 4.49^2/(2 * 9.81) = \underline{0.212m}$$

2. *Minor Head Loss (H_{minor})*

This accounts for losses at fittings (bends, valves, inlet, etc.):

$$H_{minor} = \sum KL * V^2/2g = 1.05 * 4.49^2/(2 * 9.81) = \underline{\ 1.08\ m}$$

3. *Total Head Loss (H_L)*

The total head loss is the sum of major and minor losses:

$$H_{LBranch} = H_{major} + H_{minor} = 0.212m + 1.08m = \underline{1.292\ m}$$

Total head loss

$$H_{Ltotal} = H_{Lmainr} + H_{LBranch} = 0.675\ m + 1.292\ m = \underline{1.979\mathrm{m}}$$

The Net Head (H_{net}) available to drive a turbine is the static head minus the total head loss:

Where

$$H_{static} = 408 - 378.5 = \underline{29.5m}$$

Therefore

$$\mathrm{H_{net} = H_{static} - HL = 29.5\ m - 1.967m = \underline{27.53m}}$$

6.4 Hydropower Turbines Selection and Analysis

The central aim in selecting and analyzing the turbine for this project is to establish an economically balanced design that maximizes the mechanical power extracted by the runner while keeping the initial investment as low as reasonably possible. Achieving this balance requires a careful, multi-layered evaluation of all factors that influence turbine performance and lifecycle behaviour. Considerations extend beyond the purely hydraulic characteristics to include economic suitability, long-term durability, and the overall practicality of the technology with respect to daily operation and routine maintenance.

An essential element shaping this choice, particularly because the plant depends on an irrigation outlet is the turbine’s ability to perform effectively under highly variable flow conditions. The selected turbine must sustain strong, stable efficiency over a broad operating range so that electrical generation can proceed without interfering with the water delivery requirements of the irrigation system. Within this framework, the Kaplan turbine emerges as a highly suitable option. Its principal advantage lies in its double-regulation system, which allows the guide vanes and runner blades to be adjusted independently and simultaneously. This capability ensures that the turbine maintains optimal hydraulic angles as flow conditions fluctuate, enabling it to deliver consistently high efficiency even when water availability changes dramatically throughout the year.

Although the final selection must be refined through detailed iterative analysis, the initial and most decisive step in narrowing the turbine options is determining the project's Specific Speed (*Ns*). This parameter offers a non-dimensional measure that directly links the available head and power to the corresponding rotational speed, making it one of the most reliable indicators for identifying the turbine families' best suited to the site's hydraulic regime. Establishing the Specific Speed therefore provides a clear starting point for the subsequent design iterations, a process conceptually represented in the Figure 6.1.

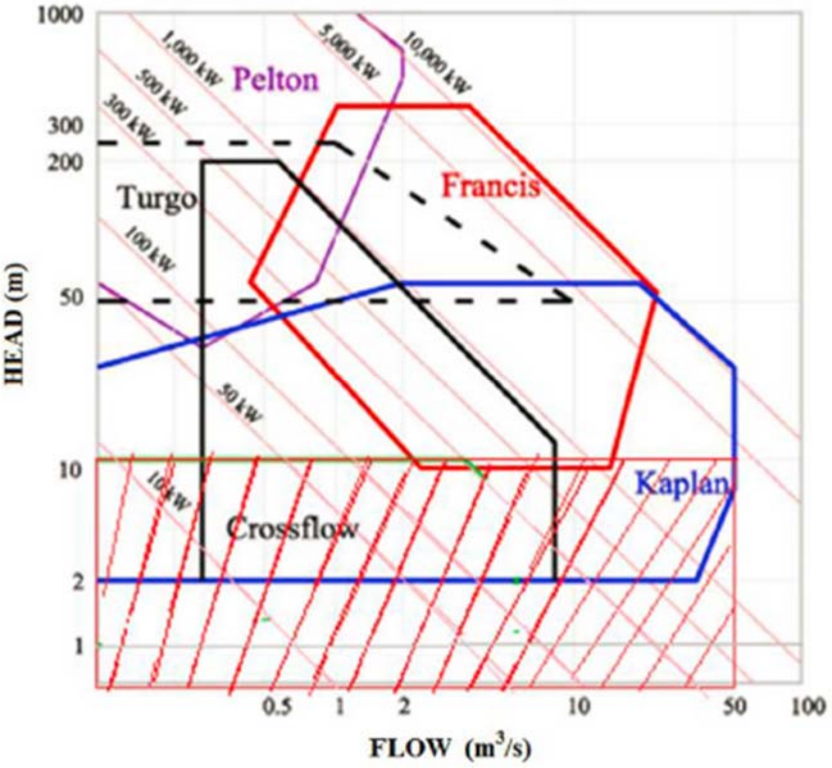


Figure 6.7. Hydro-turbines characteristics in terms of water head and flow rate.

6.3.1. Number of Unit Determination

Number unit for option I and II

The decision to install two identical generating units (Z=2) is a deliberate strategy rooted in maximizing operational flexibility, system efficiency, and maintenance reliability, while remaining strictly constrained by site-specific physical and financial limitations.

1. Enhancing Flexibility and Efficiency under Load Variation

Relying on two units gives the system greater freedom to respond to changes in available discharge and shifting patterns of power demand. When the inflow decreases, whether because irrigation demand is temporarily lower or electrical consumption drops, one unit can simply be taken out of service. In doing so, the second unit continues to run much closer to the point where it performs most efficiently, something a single large unit would struggle to achieve when forced to operate under partial load. This arrangement also makes it easier to adjust generation while safeguarding the volume of water required for irrigation, which the project must always prioritize.

2. Streamlining Maintenance and Ensuring Availability

Using identical equipment for both units strengthens the reliability of the entire plant. If one machine needs inspection, repair, or routine servicing, the other unit remains available to continue generating electricity, which protects both the operational continuity and the financial return of the facility. Having identical units also reduces the complexity of maintenance work. The inventory of spare parts is smaller and more manageable, and the procedures for inspection and repair become more uniform. This consistency helps shorten service interruptions and gives the project a more predictable set of long term maintenance costs.

3. Constraint: Site Limitations and Cost Implication

The selection of Z=2 represents the maximum feasible number of units for this project, as dictated by severe external constraints i.e. physical area limitations and cost efficiency celling. The actual powerhouse site conditions; specifically the limited, confined area available for excavation and construction, preclude the installation of a third or subsequent unit. Expanding the powerhouse to accommodate more units is physically restricted by the irrigation outlet topography and proximity to existing infrastructure.

Increasing the number of units beyond two would incur a disproportional increase in the initial investment cost. The marginal benefit in efficiency or redundancy from a third unit does not economically justify the massive added expense related to expanded civil works (excavation, larger powerhouse building) and the procurement of additional electromechanical components.

Number unit for option III

Because the flow in Option Three is exceptionally consistent or 100% dependent of considering from environmental release flow, we have the opportunity to simplify the design. A single unit would be both sufficient and efficient for the small power levels provided

6.3.2. Determination of Power

A preliminary overall turbine efficiency of 0.90 (or 90%) has been selected for initial power calculations. This temporary value is based on the assumption that a Kaplan runner will be chosen, as it represents the optimum efficiency typically achieved by different Kaplan turbine designs. The final, verified efficiency will ultimately depend upon the specific turbine model selected and the operational load variation.

For Option I Taking the data or assumption of H=28.72m, Q=73m^3/s, h=0.9

With the above given data the power $P = \eta \ell g h q\ /1000\ (kw)$

Total power = 18504 kW

Since number unit (i) = 2

The power for one unit = $\frac{p}{i}$ = 9252.1kw

For Option II Taking the data or assumption of H=27.5m, Q=73m^3/s, h=0.9

With the above given data the power $P = \eta \ell g h q\ /1000\ (kw)$

Total power = 17726 kW

Since number unit (i) = 2

The power for one unit = $\frac{p}{i}$ = 8865kw

For Option III- Taking the data or assumption of H=5 m, Q=5 m3/s, h=0.9

With the above given data the power $P = \eta \ell g h q\ /1000\ (kw)$

Total power = 220 kW

Since number unit (i) = 1(because we have hundred percent dependable flow)

The power for one unit = $\frac{p}{i}$ = 220.7kw

6.3.3. Determination of Rotation Speed and Specific Speed

The selection of the synchronous rotational speed (*N*) is a critical design choice constrained by three major technical and economic factors. The final speed must ensure the longevity of the equipment while maintaining strict electrical grid synchronization requirements and minimizing overall plant cost.

6.3.3.1 Specific speed and speed for Option I

The determination of the optimal rotational speed for a hydroelectric unit is an iterative and critical engineering process rooted in the Specific Speed (*Ns*) concept. This dimensionless parameter is the primary index used to classify and select the correct turbine type for a given head and power output .The process begins by using established trend specific speed charts empirical curves derived from the operational data of successful existing turbines, to get an initial, estimated *Ns* value based on the design net head (H_{net}). This initial Ns is then used in the specific speed formula to calculate the turbine's theoretical best rotational speed (N):

Accordingly the accepted methodological approach for this process references established empirical data, such as the trend specific speed curves published by Sieve and Leva (1988)

$$Ns\ (Trend) = 2419/H^{0.489} \qquad (Ns=3Nq)$$

$$= 2419/\ (28.72)^{0.489} = \quad 468.4$$

The next step is the Calculation of the Theoretical Turbine Speed (*N*), *P*= 9252Kw

$$N_{Calculated} = Ns\ (Trend) * H^{5/4}/P^{1/2}$$

$$= 468.4 * 28.72^{5/4}/9252^{1/2} = \underline{323rpm}$$

Now select the nearest available speed that is synchronous with the 50Hz grid frequency, while also adhering to the often-required manufacturing constraint that the number of poles (*p*) be a multiple of four for optimal generator design and balance.

$$N=120*f/p$$

Approximation and determination of rotational speed

Both 375 rpm and 300 rpm meet the constraint that the number of poles be a multiple of four 300 rpm is numerically closer to your theoretical speed (323rpm) with a difference of only 23rpm.375 rpm has a larger difference of 52 rpm. Therefore, 300 rpm is selected approximate which is the closest viable speed and corresponds to 20 poles (p=20).

Recalculate Actual Specific Speed (Ns, actual): Use N_{final} = 300 rpm and P=9252Kw in the specific speed formula to find the actual operating point.

$$Ns= N*P^{1/2}/H^{5/4}$$

$$= 300*9252^{1/2}/28.72^{5/4} = 434$$

6.3.3.2 Specific speed and Speed for Option II

Using the same approach with Option I for H_{net} =27.53m and **P** =8863Kw

Accordingly

$$N_{s\ (Trend)} = 2419/H^{0.489} \qquad (Ns=3Nq)$$

$$=2419/27.53^{0.489} = 478 \qquad .... \qquad \text{(Trend)}$$

The next step is the Calculation of the Theoretical Turbine Speed (*N*) with *P*= 8863Kw

$$N_{Calculated} =Ns_{\ Trend} *H^{5/4}/P^{1/2}$$

$$= 476*27.7^{5/4}/8863^{1/2} = \underline{320\ rpm}$$

Now select the nearest available speed that is synchronous with the 50 Hz grid frequency, while also adhering to the often-required manufacturing constraint that the number of poles (p) be a multiple of four for optimal generator design and balance.

$$N = 120 * f/p$$

Approximation and determination of rotational speed

Both 375 rpm and 300 rpm meet the constraint that the number of poles be a multiple of four.300 rpm is numerically closer to theoretical speed (320 rpm) with a difference of only 20rpm.375 rpm has a larger difference of 55 rpm. Therefore, 300 rpm is selected the closest viable speed and corresponds to 20 poles (p=20).

Recalculate Actual Specific Speed (Ns, actual): Use Nfinal = 300 rpm and P=8863Kw in the specific speed formula to find the actual operating point.

$$Ns = N * P^{1/2} / H^{5/4}$$

$$= 300 * 8863^{1/2} / 27.7^{5/4} = \underline{447.9}$$

6.3.3.2 Specific speed and speed for Option III

Using the same approach with Option I for Hnet=27.53m and P =8863Kw

Accordingly

$$N_{s\ (Trend)} = 2419/H^{0.489} \quad = 2419/27.53^{0.489} = \quad 1101 \qquad\qquad (Trend)$$

The next step is the Calculation of the Theoretical Turbine Speed (N) with P= 220 .7Kw

$$N_{Calculated} = N_{s\ (Trend)} * H^{5/4} / P^{1/2} = 1101 * 5^{5/4} / 220.7^{1/2} = 554 \text{ rpm}$$

Now select the nearest available speed that is synchronous with the 50 Hz grid frequency, while also adhering to the often-required manufacturing constraint that the number of poles (p) be a multiple of four for optimal generator design and balance.

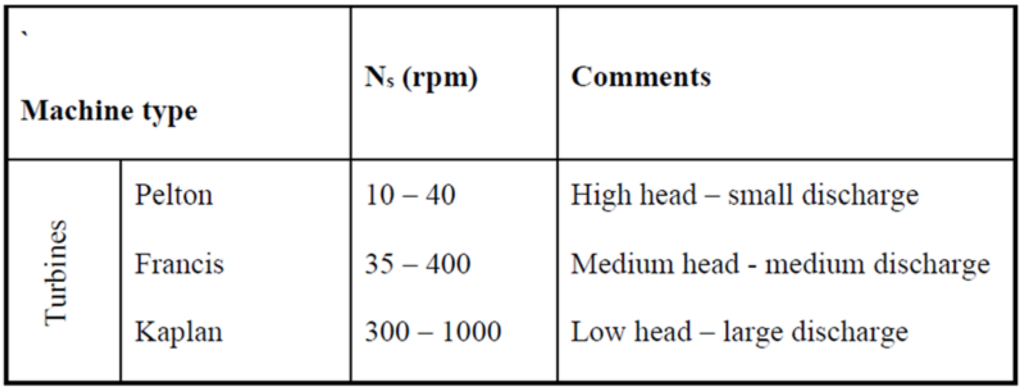
$$N= 120*f/p$$

Approximation and determination of rotational speed

500 rpm is selected the possible and closest viable speed and corresponds to 12 poles (p=12) with number of pole is multiple of 4. Recalculate Actual Specific Speed (Ns, actual): Use N(final) = 750 rpm and P=220.7Kw in the specific speed formula to find the actual operating point.

$$Ns=N*P^{1/2}/H^{5/4} = 500*220.7^{1/2}/5^{5/4} = \underline{993}$$

Table 6.2 Types of Turbines and specific speed



Machine type		**N_s (rpm)**	**Comments**
Turbines	Pelton	10 – 40	High head – small discharge
	Francis	35 – 400	Medium head - medium discharge
	Kaplan	300 – 1000	Low head – large discharge

The result of specific speed with a rotational speed of 300 rpm verified by the above table that clearly indicate a Kaplan turbine is the optimal choice, as the calculated specific speed falls within its standard operating range as shown on the Table 6.1.

Implication: In conclusion, the Kaplan turbine is the definitive choice for all three scenarios, with configurations tailored to site-specific needs:

- Options 1 & 2 (Vertical): Optimized for retrofitting within existing spatial constraints, these units ensure a compact footprint that integrates seamlessly with the current topography.

- Option 3 (Horizontal S-Type): A single-unit configuration chosen for its superior efficiency at lower power levels. This design requires minimal space, eliminates the need for penstocks, and offers a cost-effective, streamlined solution for small-drop structure

For Option I: N = 300 rpm; Ns =b434

For Option II: N = 300 rpm; Ns = 447.4

For option III: N = 500 rpm; Ns = 993rpm

6.4 Energy Generation and Determination of Capacity Factor

The energy generation and corresponding power factor for the proposed design were initially determined via a manual calculation method utilizing Microsoft Excel, incorporating specific operational assumptions optimized for the selected Kaplan turbines.

The core assumption to do manual calculation of capacity factor is based on the superior constant efficiency characteristics of the Kaplan turbine across variable flow regimes and further since Option I and II are connected the effect of load factor is neglected on the calculation of capacity factor:

6.4.1 Flow Constraint and Operational Efficiency

The Kaplan turbine is assumed to operate at its peak design efficiency (approximated here at 90%) across a wide flow range from 30% to 100% of the design flow (Q_d) as shown on the graph below. Consequently, we shall restrict our flow analysis to the operational range where the Kaplan turbine's efficiency remains at an optimum 90%. This assumption is technically justified and strongly favoured by the characteristic flat efficiency curve intrinsic to Kaplan turbine design, which sustains high performance across a wide span of flow variability.

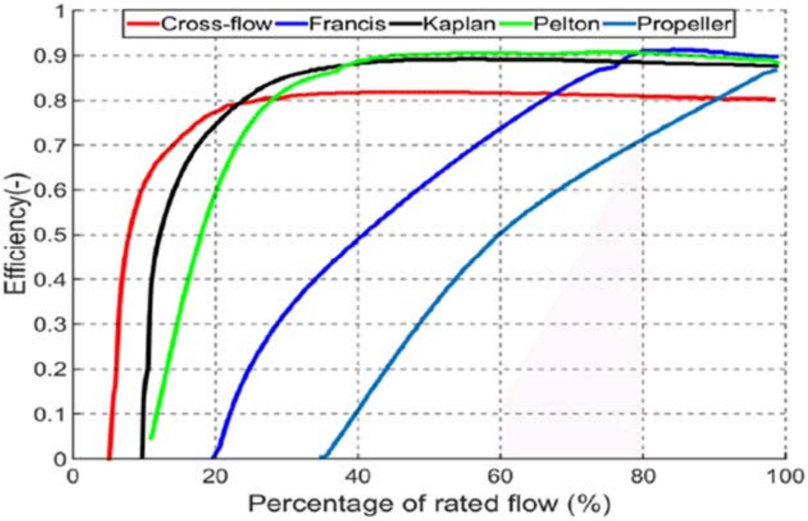


Figure 6.8 Efficiency curve Turbines

Flow Management Strategy: To sustain this high efficiency, the system is engineered to actively manage flow extremes:

- ***High Flow Management***: Any flow exceeding 100% of the design flow is tripped or bypassed.
- ***Low Flow Management***: Any flow dropping below the 30% threshold is managed by shutting down one of the two installed units

Table 6.3 Determination of Design flow from FDC

Level of Exceedance	Out Flow From Dam in 3m/S	Turbine Design Flow	No Of Unit To Be Operated	Comment
100	35.4	35.4	1	
95	37.4	37.4	1	
90	38.0	38.0	1	
85	38.9	38.9	1	
80	39.9	36.5	1	100% extra trimmed
75	40.7	36.5	1	100% extra trimmed
70	45.6	45.6	2	
65	52.0	52.0	2	
60	52.1	52.1	2	

55	53.5	53.5	2	
50	56.9	56.9	2	
45	66.7	66.7	2	
40	69.2	69.2	2	
35	71.2	71.2	2	
30	73.0	73.0	2	100%
25	73.2	73.0	2	100% extra trimmed
20	73.5	73.0	2	100% extra trimmed
15	75.3	73.0	2	100% extra trimmed
10	78.8	73.0	2	100% extra trimmed
5	80.1	73.0	2	100% extra trimmed
0	81.0	73.0	2	100% extra trimmed

6.4.2 Technical Steps for Capacity Factor Determination

In addition to the fundamental input from the Flow Duration Curve, determining the Capacity Factor (C_f) requires a systematic computation of hydraulic parameters, available head, and generated power. The following steps ensure the accurate calculation of C_f

Velocity and Flow Rate Analysis

The flow velocity within the penstock is directly calculated using the fundamental Continuity Equation ($Q = A .V$), where the pipe's cross-sectional area (A) is known and the turbine flow (Q) is dictated by the FDC. This step is essential as velocity is a critical input for head loss computation.

- For Option I continues 247 m of 6m diameter steel penstock assumed
- For Option II we have two cross section of 187m of 6m diameter penstock and 47m of diameter 4.55m branch pipe

Available Head Analysis and Head Loss Calculation

The system's energy potential is quantified by rigorously 67analysing the available static head, which dictates the Gross Head (Hg).For preliminary case the rated head considered here where there is no too much fluctuation in the reservoir. The hydraulic efficiency of the conveyance system must be quantified by calculating the head losses (h_L). This includes:

Friction Head Loss (h_f): Calculated based on the computed flow velocity and pipe geometry (using Darcy-Weisbach or similar friction equations).

- Minor Head Losses (h_m): Calculated for entrance, bends, valves, and transitions.
- The Net Head (H_{net}) = Hg- h_L is then determined for all operating points.

Shaft-to-Wire Efficiency Recommendations after Turbine

Since the turbine power have been already calculated, next is to define the "Shaft-to-Wire" efficiency to find the power at the grid connection Based on industry standards (such as IEC 60041 and ASME PTC 18), here are the reference values you should consider

Generator (h_{gen}) *95.0% – 98.5% let us take 97.0% (Standard for synchronous units)*

Step-up Transformer (h_t) *98.0% – 99.5% let us take 99.0%*

Station Service/Auxiliary (h_s) *0.5% – 1.0% let take loss 0.99 (Multiplier)*

Therefore

*Combined efficiency (Shaft-to-Wire) =0.97*0.99*0.99=0.95* or

Total combined efficiency $=h_{turbine} * h_{shat-to-wire}$ *=0.9*0.95=0.855*

The availability is 95% according IFC (World Bank Group) data then the energy can be calculated with product on power calculation combined efficiency and the availabity with time

Power and Energy Computation

Once the net head is known across the flow duration curve, the output is calculated:

- Power Generated (P): The instantaneous electrical power generated is computed at all flow points using the standard hydraulic power formula, incorporating the Net Head and the assumed turbine efficiency.

- Annual Energy I: The total annual energy production is calculated by integrating the computed power output over the entire period defined by the Flow Duration Curve.

$$E_{avail}=\sum_{k=1}^{20}\frac{(P_{5(K-1)}+P_{5k})}{2}*\frac{5}{100}*8760*(1-l_{dt})$$

Table 6.4 Option I: Power and energy computations

Turbine flow(m3/s)	No of unit to be operated	Velocity main pipe	H loss main pipe	Static Head	Net Head	Power(KW)	Energy (KWH)
35.4	1	1.252789	0.182786	29.5	29.32	8696.91	3,642,987
37.4	1	1.321958	0.203527	29.5	29.30	9170.59	3,769,387
38.0	1	1.343346	0.210166	29.5	29.29	9316.85	3,843,582
38.9	1	1.375201	0.220252	29.5	29.28	9534.50	3,771,369
36.5	1	1.291578	0.19428	29.5	29.31	8962.67	3,654,780
36.5	1	1.291578	0.19428	29.5	29.31	8962.67	4,099,780
45.6	2	1.612061	0.302657	29.5	29.20	11145.23	4,855,834
52.0	2	1.838455	0.393634	29.5	29.11	12670.84	5,173,109
52.1	2	1.843005	0.395586	29.5	29.10	12701.35	5,249,538
53.5	2	1.894428	0.417968	29.5	29.08	13045.69	5,483,413
56.9	2	2.014792	0.472767	29.5	29.03	13848.42	6,112,273
66.7	2	2.361095	0.649253	29.5	28.85	16130.02	6,692,477
69.2	2	2.447784	0.697804	29.5	28.80	16694.10	6,902,408
71.2	2	2.519684	0.7394	29.5	28.76	17159.65	7,082,857
73.0	2	2.584758	0.778085	29.5	28.72	17579.14	7,168,387
73.0	2	2.584758	0.778085	29.5	28.72	17579.14	7,168,387
73.0	2	2.584758	0.778085	29.5	28.72	17579.14	7,168,387
73.0	2	2.584758	0.778085	29.5	28.72	17579.14	7,168,387

73.0	2	2.584758	0.778085	29.5	28.72	17579.14	7,168,387
73.0	2	2.584758	0.778085	29.5	28.72	17579.14	7,168,387
73.0	2	2.584758	0.778085	29.5	28.72	17579.14	-
∑E							113,344,118

Table 6.5 Option II: Power and energy computations

Flow in m3/s (FDC)	Turbine flow(m3/s)	No of uni	Velocity main pipe	velocity branch pipe	H loss main pipe	H loss branch pipe	Static Head	Net Head	Power(KW)	Energy (KWh)
35.4	35.4	1	1.252788626	2.1785	0.158788	0.303956	29.5	29.04	8613.9	3,606,159
37.4	37.4	1	1.321958213	2.29878	0.176806	0.338447	29.5	28.98	9073.0	3,728,615
38.0	38.0	1	1.343346177	2.335972	0.182573	0.349487	29.5	28.97	9214.5	3,800,309
38.9	38.9	1	1.375200592	2.391364	0.191335	0.366258	29.5	28.94	9424.6	3,730,417
39.9	36.5	1	1.291578202	2.245952	0.168773	0.32307	29.5	29.01	8871.7	3,617,670
40.7	36.5	1	1.291578202	2.245952	0.168773	0.32307	29.5	29.01	8871.7	4,045,148
45.6	45.6	2	1.612060919	2.803246	0.26292	0.50329	29.5	28.73	10968.3	4,766,244
52.0	52.0	2	1.838454795	3.196927	0.341954	0.654578	29.5	28.50	12408.4	5,065,686
52.1	52.1	2	1.843005426	3.20484	0.343649	0.657822	29.5	28.50	12436.9	5,137,077
53.5	53.5	2	1.894427553	3.294259	0.363093	0.695042	29.5	28.44	12758.5	5,354,428
56.9	56.9	2	2.014791734	3.503562	0.410697	0.786168	29.5	28.30	13503.0	5,928,485
66.7	66.7	2	2.361094729	4.105756	0.564012	1.079648	29.5	27.86	15574.1	6,452,820
69.2	69.2	2	2.447784243	4.256502	0.606189	1.160383	29.5	27.73	16074.6	6,638,341
71.2	71.2	2	2.519684208	4.38153	0.642323	1.229553	29.5	27.63	16484.0	6,794,554
73.0	73.0	2	2.583156405	4.491903	0.675092	1.29228	29.5	27.5	16840.8	6,999,059
73.2	73.0	2	2.589308857	4.491903	0.458079	0.452853	29.5	28.59	17487.0	7,130,417

73.5	73.0	2	2.599775308	4.491903	0.461227	0.452853	29.5	28.59	17485.1	7,127,519
75.3	73.0	2	2.665759453	4.491903	0.481316	0.452853	29.5	28.57	17472.8	7,120,265
78.8	73.0	2	2.787261292	4.491903	0.519392	0.452853	29.5	28.53	17449.5	7,113,564
80.1	73.0	2	2.83595304	4.491903	0.535046	0.452853	29.5	28.51	17439.9	7,110,383
81.0	73.0	2	2.866242038	4.491903	0.544898	0.452853	29.5	28.50	17433.9	-
									∑E	111,267,161

The Capacity Factor (C_f) is then formally calculated using the Annual Energy output and the maximum Installed Capacity (Pins)

$$C_f=111,267,161 / (16840.8*8760) = \underline{0.754}$$

For Option III

Given that Option III benefits from 100% flow dependability, the capacity factor is projected to align directly with the plant's availability (95%). The final installed capacity will be formally determined after accounting for all cumulative mechanical and electrical efficiency losses which has installed capacity after 209.7kw after all efficiency considered.

6.5 Determination of Turbine Parameters

6.5.1 Determination of the Diameter of Runner

Determination of the outer runner diameter is important because we take as the base for determination powerhouse and equipment sizing by proportionality the basic diameter is D_M shown below with formula Sieve and De Leva (1978). The determination of the outer runner diameter (*DM* or *Dmax*) as shown Figure 6.6 is a critical milestone in the engineering process, as it serves as the foundational dimension for the entire powerhouse layout. All subsequent equipment sizing and spatial requirements for the civil works are derived through established proportionality ratios based on this primary diameter.

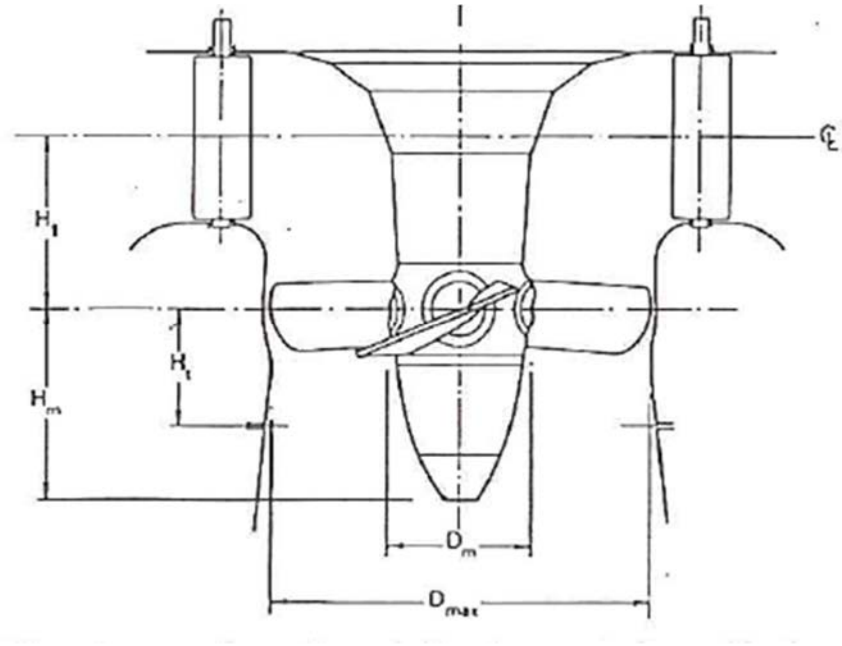


Figure 6.9 Kaplan Runner Dimensions

Following the methodology established by Sieve and De Leva (1978), the runner diameter is calculated using the peripheral Velocity Coefficient (K_u) and K_u is also related to specific speed, which relates the runner's velocity to the head. This ensures that the physical dimensions of the turbine are optimized for the site's hydraulic conditions:

$$K_u = 1.2+5.12*10^{-3}*N_s$$

And

$$D_M = 84.5*K_u*\frac{\sqrt{H_n}}{n}$$

Table 6.6 Runner diameter, Velocity Coefficient and specific speed

	H_n(Meter)	N(rpm)	N_s	K_u	D_M(Meter)
Option I	28.72	300	434	1.488	2.27
Option II	27..53	300	447.9	1.51	2.23

Now D_M is fixed and with known N_s, it is possible to determine the dimensions of the spiral casing, the draft tube, and the required spacing between units, effectively dictating the total footprint of the powerhouse.

Having the same Synchronous Speed ($N_{Synchronous}$) and turbine flow is for both Option I and Option II, and the resulting Outer Runner Diameter (DM) is negligibly different (as seen on Table 6.5), the differentiating factor lies in the influence of Specific Speed (Ns) on the remaining geometry of the equipment and the powerhouse.

6.5.2 Determination of the Dimensioning of Scroll case

The dimensions of the scroll case, as illustrated in the figure below, were derived using the mathematical formulas established by Siervo and De Leva (1978), specifically referencing the parameters outlined in Table 6.6

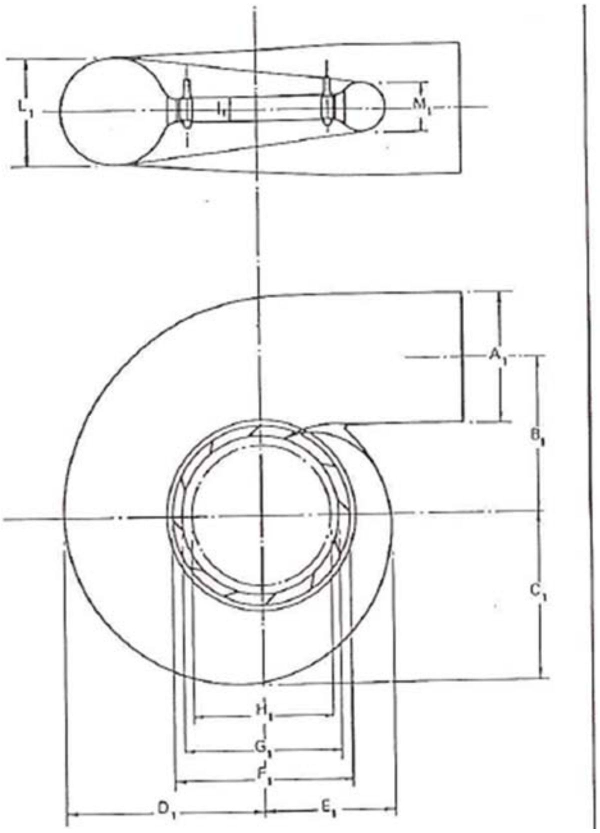


Figure 6.10 Main spiral case Dimension

Table 6.7 Dimensioning Scroll case

	Formula	**Option I**	**Option II**
A	$\frac{A}{D_3}$=0.4*$N_s^{0.2}$	3.92	3.91
B	$\frac{B}{D_3}$=1.26+3.79*10^{-4}*N_s	4.14	4.12
C	$\frac{C}{D_3}$=1.46+3.24*10^{-4}*N_s	4.01	3.99
D	$\frac{D}{D_3}$=1.59+5.74*10^{-4}*N_s	5.53	5.32
E	$\frac{E}{D_3}$=1.21+2.75*10^{-4}*N_s	3.86	3.84
F	$\frac{F}{D_3}$=1.45+72.17/N_s	4.7	4.64
G	$\frac{G}{D_3}$=1.29+41.63/N_s	4.03	3.98
H	$\frac{H}{D_3}$=1.31+31.86/N_s	4.02	3.98
I	$\frac{I}{D_3}$=0.45-31.8/N_s	1.09	1.09
L	$\frac{L}{D_3}$=1.26+3.79*10^{-4}*N_s	3.25	3.24
M	$\frac{\boldsymbol{M}}{\boldsymbol{D_3}}=\frac{\mathbf{1}}{(\mathbf{2.06-1.2*10^{-3}*}\boldsymbol{N_s})}$	1.89	1.89

6.5.3 Determination of the Dimensioning of Draft Tube

The dimensions of the draft tube , as illustrated in the figure below, were derived using the mathematical formulas established by Siervo and De Leva (1978), specifically referencing the parameters outlined in Table 6.67

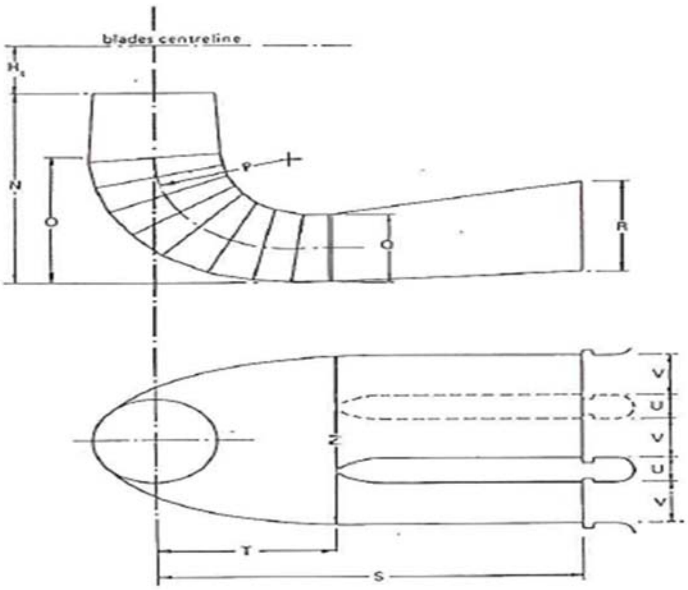


Figure 6.11 Main Draft Tube Dimension

Table 6.8 Dimensioning Daft Tube

	Formula	Option I	Option II
H_t	$\frac{H_t}{D_3}$=0.24+7.82*10^{-5}*N_s	0.8	0.79
N	$\frac{N}{D_3}$=2.00-2.14*10^{-6}*N_s	5.81	5.76
O	$\frac{O}{D_3}$=1.4-1.67*10^{-5}*N_s	4.05	4.01
P	$\frac{P}{D_3}$=1.26-16.35/N_s	3.55	3.52
Q	$\frac{Q}{D_3}$=0.66-18.4/N_s	1.8	1.78
R	$\frac{R}{D_3}$=1.25 – 7.98*10^{-5}*N_s	2.63	2.57
S	$\frac{S}{D_3}$=4.26+201.51/N_s	13.73	13.56
T	$\frac{T}{D_3}$=1.2+5.12*10^{-3}*N_s	9.95	10.06
Z	$\frac{Z}{D_3}$=2.58+102.66/N_s	8.19	8.09

As you can see in the following picture, the dimensions fromExcel template to demonstrate that the physical difference between Option 1 and Option 2 is minimal

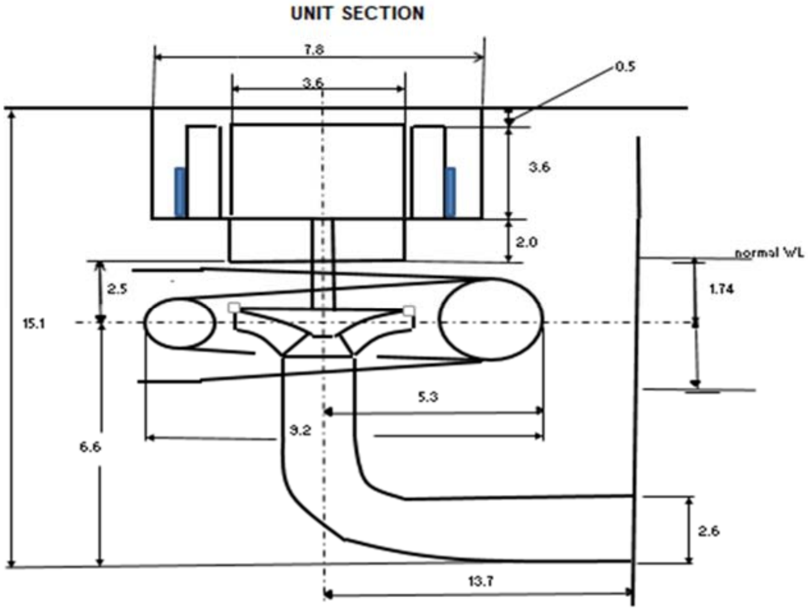


Figure 6.9 Overall Dimension of generating unit for Option I

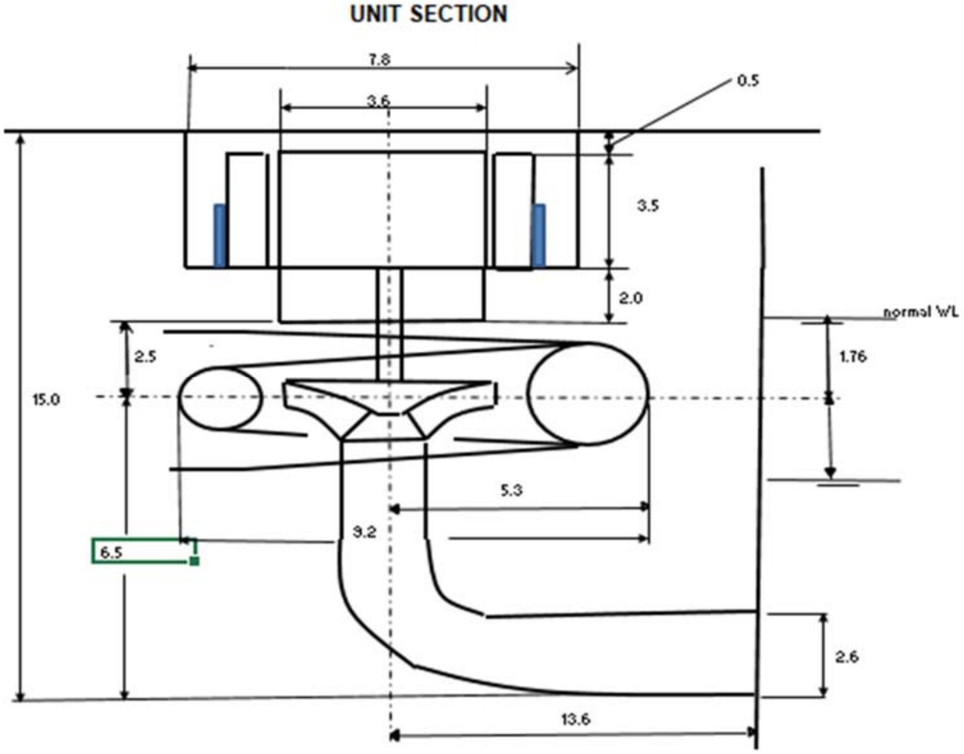


Figure 6.10 Overall Dimension of generating unit for Option II

6.5.4 Dimensions of Power House

The three essential constituents of power house are: Unit bay, Erector bay and Control bay. Vertical setting is better for multiple units. The size of the erector bay is usually governed by the size of the generator. Normally, in the case of surface power house, the width of the erector bay is equal to the machine hall width and the length equals that of one operating bay or center to center distance of two adjacent units.

The control room and the office may be adjacent to the power house or may be located in separating buildings located above the ground. Unit spacing can be determined using the following empirical formula

D=2.27*D3 …………………. …………………………. J.J Donald's formula

Unit spacing =3.5 - 6D3, take 4.75D3 (average)

=4.75*2.27=10.79m …….. (for Option I)

=4.75*2.23=10.6m …….. (for Option II)

A minimum of 2 to 3 meter is recommended for unit space clearance, Let us consider 2.5m and we have two unit and we can considering one unit size for erection bay but we will leave one unit size for control spacing that can be considered later in the width side due space limitation

Number of units size in consideration =2unit+1unit for erection bay=3 units (including free space)

$$L\ (option1) = 3*(10.79+2.5) = \underline{39.86m}$$

$$L\ (Option\ II) = 3*(10.6+2.5) = \underline{39.3m}$$

Therefore

Let us take LT_{otal} *for Option I and II is approximated* $\underline{40m}$

The width of machine hall can be determined by the size and the clearance space from the walls needed as a gangway.

Width centre-to-centre distance of the unit spacing. = $\underline{17.6m}$

$$W = F + C + 2 + 1.85D3$$

For Option I: considering F=4.7m, C=4.01m and D=2.27

For Option II: F=4.64m, C=3.99m and D=2.23

Where, F and C are calculated in the dimensioning of spiral casing

Therefore

$$Width\ (Option\ I) = 4.7+4.01+2+1.85*2.27=14.9m$$

$$Width\ (Option\ II) = 4.6+3.99+2+1.85*2.23=14.76m$$

The powerhouse width is set at 25 m for both option, comprising 15 m for the two turbine units and their required clearances, plus an additional 10 m dedicated to the control and electrical bay.

Height of power house (H)

The height of the machine hall is fixed up by the head room requirement of the crane operation. The hall must have the height which will enable the cranes to lift the rotors of the generator clear of the floor without any other machine sets forming obstruction.

H =Height of generator +clearance (4m)+allowance for free movement of crane (say 2m) + allowance for crane girders (say 3 m)

$$H =3.3+4+2+3;$$

$$H =12.3m\ say\ 13m;$$

$$H=13m;$$

Therefore the dimensions of the power house are =Length * width *height = 40*25*13 for both option I and Option II

6.6. Quantification of Civil Works and Material Volumes

Given that this is a retrofit project, the majority of the civil infrastructure is already in place except tunnel work for Option I. Therefore, this section calculates the additional civil work quantities, which primarily includes the construction of the powerhouse structure and tailrace channel, the volume of back excavation needed from the mountain abutment for footprint of the powerhouse at the dam's toe. The study utilized the Japan International Cooperation Agency, (2011) manual as a guideline to quantify civil works and material volumes.

6.7. Powerhouse Civil Quantity Take-Off for Option I and II

The total volume of civil work required for the powerhouse, particularly the concrete volume, can be quickly and effectively estimated by applying established empirical formulas derived from historical power plant construction data. This preliminary quantity is directly dependent on key design parameters: the maximum plant flow (Qmax), the effective net head (Hnet), and the number of generating units (n). These formulas allow for a high-level, initial quantity take-off without detailed structural drawings, establishing a crucial basis for preliminary cost analysis

Where

$Q = 73\ m^3/sec$;

$He = 28.72$;

n (number of unit) $= 2$;

Excavation quantity: $V_e = 97.8*(Q * He^{2/3} * n^{1/2})^{0.727} = \underline{14{,}492.13\ m^3}$

Concrete quantity: $V_c = 28.1*(Q * He^{2/3} * n^{1/2})^{0.795} = \underline{6{,}645.77\ m^3}$

Reinforcement in ton: $Wr = 0.046*V_c^{0.795} = \underline{332.29\ ton}$

6.8 Tailrace Channel Civil Quantity Take-off for Option I and II

The civil work quantity for the tailrace channel is determined by the required cross-sectional dimensions, which are calculated based on the maximum Plant Flow (*Q*) and (*R*), where *R* is established in Section 2 (See hydraulic design section).

Accordingly substituting in the following formula

$$Q=73\ m^3/sec \text{ and } R=2.6\ m$$

Excavation quantity: $V_e = 395*(R * Q)^{0.479} = \underline{6{,}994.19\ m^3}$

Concrete quantity: $V_c = 40.4*(R * Q)^{0.684} = \underline{1{,}819.12\ m^3}$

Reinforcement in ton: $W_r = 0.278*V_c^{0.610} = \underline{27.07\ ton}$

6.9. Estimation of Excavation at Dam Toe (abutment) for Powerhouse Footprint for Option I and II

The powerhouse location, where the embedded penstock emerges at the irrigation tail-water, demands substantial excavation into the mountain slope to form the Powerhouse Footprint. The required excavation width is dictated by the powerhouse structure width and the necessary area for the hydraulic bifurcation. The removal volume will be conservatively calculated as a large right triangle, extending from the required foundation level (above the 387 m elevation) up to the natural slope, plus a safety tolerance.

Based on the layout drawings and incorporating necessary tolerance, the total excavation width required is 50m for Option I and 70 m for Option II. The corresponding elevation on the terrain is 400masl and 405masl respectively

Therefore

$$\text{Option I: } V_c = 0.5*(400-387)(50) = \underline{13{,}000\ m^3}$$

$$\text{Option II: } V_c = 0.5*(405-387)(700) = \underline{25{,}200\ m^3}$$

CHAPTER SEVEN

PRELIMINARY FINANCIAL AND ECONOMIC ANALYSIS

7.1. Cost Derivation of Initial Investment

The cost estimate reflects the overall expenditure that the contractor is expected to incur for the execution of the building works. It is derived using standardized unit rates adopted from the NPV reference values, which provide a consistent basis for preliminary financial assessment. Material transport costs are calculated on a volumetric basis, while expenses related to blasting, loading, and transportation are estimated per cubic meter of excavated material. Formwork costs are assessed according to the required surface area, and reinforcement expenses are determined based on the applicable unit rate for steel installation. Concrete works are valued using an established unit cost per cubic meter to account for production, placement, and finishing. In addition to these primary construction items, an allowance equivalent to twenty percent of the subtotal is included to cover fixtures and fittings, ensuring that all ancillary components necessary for functional completion are adequately represented in the overall cost estimate.

7.2 Determination of Civil Work Cost

The cost estimate represents the contractor's total expenditure for the building works, calculated using the following standardized unit prices from NPV: Material Transport: 2.2 USD/m^3, Blasting, Loading, and Transport: 7.0 USD/m^3, Formwork: 10.4 USD/m^2, Reinforcement: 633 USD/m^3, Concrete: 48 USD/m3 and Fixtures and Fittings: 20% of the total cost of the items above

7.2.1. Powerhouse Civil Works Cost Estimate

The following tables present a detailed breakdown of the civil works costs associated with the powerhouse and tailrace structures for Options I and II. The cost estimates are prepared using consistent unit prices and are expressed in United States dollars, allowing a clear and transparent comparison between the two alternatives.

Option I: Powerhouse Civil Works Cost Estimate

The following Table 7.1 summarizes the powerhouse civil works cost for Option I, with a total estimated cost of USD 1,210,320.92. Excavation activities form a significant component of this cost. Excavation of the abutment involves a volume of 13,000 m^3 at a unit rate of USD 9 per cubic meter, resulting in a cost of USD 117,000. Excavation specifically for the powerhouse foundation amounts to 14,492.13 m³, with a corresponding cost of USD 130,429.21. Structural works dominate the overall expenditure, particularly concrete works, where 6,645.77 m³ of concrete at a unit price of USD 58.4 per cubic meter results in a total of USD 388,112.84. Reinforcement steel also represents a major cost item, with 332.29 tons priced at USD 633 per ton, amounting to USD 210,338.55. Additional costs are included as percentage allowances, with drainage and related items estimated at 20 percent of the main works, totaling USD 145,776.12, and the powerhouse building superstructure, estimated at 30 percent, contributing USD 218,664.18.

Table 7.1 Powerhouse civil cost for option I (USD)

Civil Work	**Volume**	**Unit Price**	**Total Price**
Excavation of abutment (m^3)	13000	9	117,000.00
Excavation for PH (m^3)	14,492.13	9	130,429.21
Concrete for PH (m^3)	6,645.77	58.4	388,112.84
Reinforcement bar (ton)	332.29	633	210,338.55
Others items i.e. drainage (20%)			145,776.12
PH Building (30%)superstructure)			218,664.18
Total			1,210,320.92

Option II: Powerhouse Civil Works Cost Estimate

As the Table 7.2 depicts the powerhouse civil works cost for Option II, which totals USD 1,320,120.92. Most cost components remain identical to Option I, including excavation for the powerhouse, concrete works, reinforcement, and percentage-based allowances. The main difference arises from the excavation of the abutment, which increases to 25,200 m³ in Option II. At the same unit rate of USD 9 per cubic meter, this results in a higher excavation cost of USD 226,800, explaining the overall increase in total cost compared to Option I.

Table 7.2 Powerhouse civil cost for option II (USD)

Civil Work	**Volume**	**Unit Price**	**Total Price**
Excavation of abutment (m^3)	25200	9	226,800.00
Excavation for PH (m^3)	14,492.13	9	130,429.21
Concrete for PH (m^3)	6,645.77	58.4	388,112.84
Reinforcement bar (ton)	332.29	633	210,338.55
Others items i.e. drainage (20%)			145,776.12
PH Building (30%)superstructure)			218,664.18
Total			***1,320,120.92***

7.2.2 Tailrace Civil Works Cost Estimate

The tailrace civil works cost, which is identical for both options, with a total estimated cost of USD 232,903.15 as shown on Table 7.3. Excavation accounts for USD 62,947.74, concrete works for USD 106,236.63, and reinforcement steel for USD 17,138.15. An additional 25 percent allowance for drainage and miscellaneous items amounts to USD 46,580.63. Overall, the results indicate that the cost difference between the two options is mainly driven by increased abutment excavation at the powerhouse, while tailrace costs remain unchanged.

Table 7.3 Tailrace civil works cost for option I and II (USD)

Civil Work	**Quantity**	**Unit Price**	**Total Price**
Excavation	6,994.19	9	62,947.74
Concrete	1,819.12	58.4	106,236.63
Reinforcement bar (ton)	27.07	633	17,138.15
Others items i.e. drainage (25%)			46,580.63
			232,903.15

7.2.3 Tunnel Works Cost Estimate for option I

The tunnel works cost estimate has been developed using a scaling approach based on historical expenditure data from the Tendaho project. The original tunnel construction cost recorded in 2005 provides a suitable benchmark due to similarities in construction methods, project context, and regional conditions. By applying the historical exchange rate and converting the cost into USD the estimated cost of tunnel excavation and lining is approximately USD 3.75 million.

This estimate implicitly includes drilling, blasting, muck removal, installation of initial support, and concrete lining works. While the approach does not fully capture site-specific geological uncertainties, it offers a conservative and transparent approximation that is appropriate for a preliminary financial assessment. The use of historical cost data helps to reduce uncertainty at this stage of project development, where detailed geotechnical investigations may not yet be available.

As the project advances to subsequent design stages, this tunnel cost estimate should be refined using detailed geological surveys, updated unit rates, and market-based pricing. Such refinement will improve cost accuracy and provide a stronger basis for final investment decisions.

7.3 Determination of Electromechanical and Hydro Mechanical Cost for option I and II

7.3.1 Electromechanical Cost

The base cost is derived from the NVE (Norwegian Water Resources and Energy Directorate) cost curves for two generating units. For a design speed of n = 300 rpm, the following power-law formula is utilized

$Y=1.4722*X^{0.6195}$ = ***<u>5.8MUSD</u>***

Where:

Y: Total cost of electrometrical equipment in Million USD (MUSD).

X: Total installed power (9.25 MW).

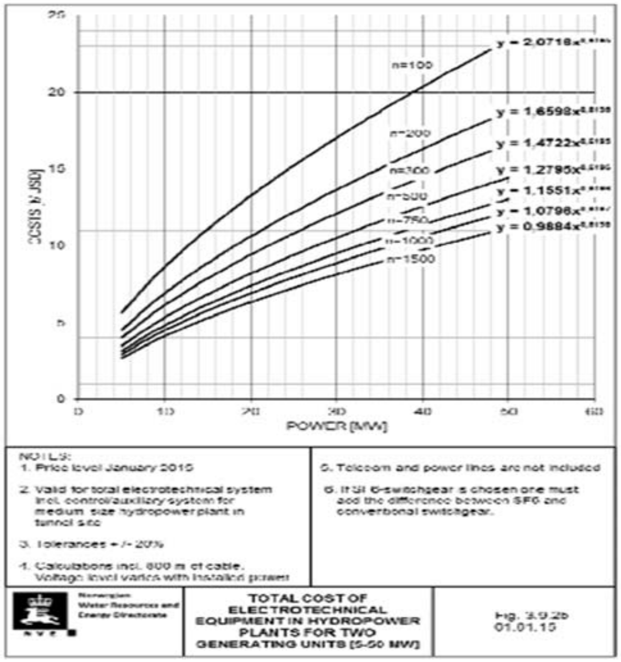


Fig. 7.1 Electromechanical cost estimate curve

Total Tolerance and Scope Adjustment

To ensure a comprehensive budget, the final estimate incorporates a 30% total contingency for total tolerance and Scope Adjustment, calculated as follows:

- ***NVE Base Tolerance***: A 20% tolerance is included as per the standard NVE price level.
- ***Infrastructure Addition***: An additional 10% is allocated specifically to cover telecom and power lines, which are originally excluded from the NVE cost figures.

Therefore, Total EM cost =1.3*5.8=7.57MUSD

7.3.2 Hydro Mechanical Cost

The hydro-mechanical cost estimate accounts for the principal equipment required for the integration of the hydropower system. It includes the provision of a 3 m diameter butterfly valve installed at the outlet of the irrigation pipeline, which is required to regulate flow under the new hydropower arrangement. The estimate also covers the draft tube gate, which is essential for operational control and for facilitating maintenance activities. The costs of these components are derived using standard unit prices applied to building works and incorporate an additional 20 percent allowance to account for fixtures and fittings. Thus

1. The price of 2.5m butterfly found from NPV curve 385,000USD and for 3m butterfly simply interpolated =1.2*385,000USD = *462,000USD*

2. The price of draft tube gate is calculated from the following correlation found from NPV

$$Y=10,500.2*A^{0.7035}$$

Where:

$$A = \text{number of unit}*(2*R*V) =2*(2*2.6*3.5) =36.4m^2$$

$$\text{Draft tube cost} =10,500.2*36.4^{0.7035}=131,650\ USD$$

7.4. Consolidated Cost Summary

A detailed comparison of the consolidated costs for Option I and Option II, is presented on Table 7.4.; clearly demonstrating substantial differences in total investment requirements and cost efficiency. The total project cost for Option I is estimated at USD 18,408,459, whereas Option II requires a significantly lower investment of USD 13,287,692. This represents a cost reduction of approximately USD 5.12 million when Option II is selected.

Civil works constitute the largest source of cost variation between the two alternatives. For Option I, the civil works subtotal amounts to USD 5,452,143. This high value is mainly driven by the construction of a new tunnel, which alone costs USD 3,749,293. In addition, the powerhouse cost for Option I is USD 1,210,321, the tailrace channel costs USD 232,903, and miscellaneous works at 5 percent amount to USD 259,626. In contrast, Option II records a much lower civil works subtotal of USD 1,630,675, as it does not require a new tunnel. The powerhouse cost for Option II is USD 1,320,121, the tailrace channel remains the same at USD 232,903, and miscellaneous works are limited to USD 77,651 (see Table 7.4)

Hydraulic equipment costs are identical for both options, with a subtotal of USD 712,380. This includes a draft tube gate costing USD 131,650, a 3-meter butterfly valve valued at USD 462,000, and a 20 percent contingency for fitting amounting to USD 118,730. Similarly, the electromechanical cost is the same for both options, fixed at USD 7,573,133, reflecting equivalent power generation capacity and equipment specifications.

When direct costs are considered, Option I totals USD 13,737,656, compared to USD 9,916,188 for Option II. Administrative and engineering services further increase costs to USD 2,060,648 for Option I and USD 1,487,428 for Option II. Contingency at 10 percent adds USD 1,373,766 for Option I and USD 991,618 for Option II, while interest during construction over two years at 9 percent amounts to USD 1,236,389 and USD 892,456, respectively as shown on Table 7.4.

Finally, the unit cost per kilowatt highlights the economic advantage of Option II, with USD 749.62 per kW compared to USD 994.84 per kW for Option I. This confirms that Option II is the more cost-efficient and financially favorable alternative.

Table 7.4 Summary of cost for option I and II

No.	**Item Description**	**Unit**	**Total Amount for Option I (USD)**	**Total Amount for Option II (USD)**
1	Civil works			
1.1	Powerhouse	lump sum	1,210,321	1320121
1.2	New tunnel for Option I	lump sum	3,749,293	0
1.3	Tailrace channel	lump sum	232,903	232903
1.4	Miselouse (5%)		259,626	77651
	Subtotal		***5,452,143***	***1630675***
2	Hydraulic equipment			
2.1	Draft tube Gate	lump sum	131,650	131650
2.2	Butterfly valve (3m)	lump sum	462,000	462000
	Contingency for fitting (20%)		118,730	118730
	Subtotal		***712,380***	***712380***
3	Electromechanical Cost	lump sum	**7,573,133**	7573133
	Direct cost		**13,737,656**	9916188

4	Administrative and engineering service	lump sum	2,060,648	1487428
5	Contingency (10%)	lump sum	1,373,766	991618
6	Interest during construction (9%) for 2 yrs	lump sum	1,236,389	892456
	Total cost(USD)		***18,408,459***	***13287692***
	USD/kw		994.84	749.62

7.5. Determination of Electromechanical and civil Cost for option III

The cost estimation for Option III is modeled after micro-hydropower benchmarks utilizing Hatata, El-Saadawi and Saad, (2019)). This valuation assumes the exclusion of penstock requirements and standard powerhouse civil works, focusing primarily on the electromechanical cost per kilowatt (kW) as detailed below

Cost per kW of powerhouse building (Civil work):

$$C_{PH} = 1389.16\, P^{-0.235}.\, H^{-0.0585} = 1389.16\, (220)^{-0.2351}.\, 5^{-0.0585} = \underline{355}$$

The cost of the Kaplan turbine

$$C_K = 10486.65\, P^{-0.58338}.\, H^{-0.113901} = 10486.65\, (200)^{-0.58338}.\, 5^{-0.113901} = \underline{1410}$$

Cost per kW of the generator (US):

$$CG = 1179.86\, P^{-0.1855}\, H^{-0.2083} = 1179.86\, (220)^{-0.1855}\, 5^{-0.2083} = \underline{310}$$

Cost per kW of electrical and mechanical auxiliary (US):

$$C_A = 612.87\, P^{-0.1892.}\, H^{-0.2118} = 612.87\, (200)^{-0.1892.}\, 5^{-0.2118} = \underline{157}$$

Cost per kW of transformer and switchyard equipment (US):

$$C5 = 281\, P^{-0.1803.}\, H^{-0.2075} = 281\, (200)^{-0.1803.}\, 5^{-0.207\,5} = \underline{76}$$

The cost per kW of electromechanical equipment, C_{EM}, is:

$$C_{EM} = C_k + C_A + C_G + C_T = 1953$$

Indirect project costs are estimated as 13% of the total civil and electromechanical cost . Based on this budgetary framework, the total cost (*TC*) per kW of the SSHP installation is formulated as follow:

$$T_C = 1.13(C_{PH} + C_{EM}) = 3002\ USD/KW$$

7.6. Feasibility Analysis of Option I, Option II and Option III

7.6.1 Option I: Financial Feasibility and Emission Analysis (RETScreen Output)

1. Project Overview

The financial feasibility and emission performance of Option I were evaluated using RETScreen, with results indicating a technically sound, economically robust, and environmentally beneficial hydropower investment. The project is based on hydro turbine technology with an installed capacity of 17,579 kW and a capacity factor of 73.6%, reflecting efficient utilization of the available water resource as shown on Table 7.5. Over a projected operational life of 35 years, the plant is expected to export approximately 113,338 MWh of electricity annually to the national grid. With an electricity export tariff of 0.06 USD/kWh data adopted from Nganga et al., (2013 and Girma, (2016), as a benchmark tariff, and the annual revenue from power sales is estimated at about USD 6.8 million, demonstrating strong revenue-generating potential for the project.

Table 7.5 Option I: project preview

Item	Value
Technology	Hydro turbine
Power capacity	17,579 kW
Capacity factor	73.6 %
Project life	35 years
Electricity exported to grid	113,338 MWh
Electricity export tariff	0.06 USD/kWh
Electricity export revenue	6,800,288 USD

Source: RETScreen Output

2. Capital and Operating Costs

The capital cost assessment shows that the project requires a total initial investment of USD 17.49 million, corresponding to a specific investment cost of 995 USD/kW as shown on Table 7.6. This level of capital intensity is within the typical range for medium-scale hydropower developments and suggests cost efficiency in project design and implementation. In addition to the upfront investment, annual operating expenditures are estimated at USD 351,580 for operation and maintenance activities, ensuring reliable and continuous plant operation. During the first 15 years, annual debt service amounts to USD 1.34 million, resulting in total annual costs of approximately USD 1.70 million. When compared with annual electricity revenues, these costs remain relatively low, reinforcing the project's strong financial position.

Table 7. 6 Option I: Initial Investment and Annual cost

Cost component	Value
1. Initial Investment	
Specific Investment Cost	995 USD/kW
Total Initial Cost	17,491,105 USD
2. Annual Cost	
Operation And Maintenance (O&M)	351,580 USD
Debt Service (First 15 Years)	1,344,301 USD
Total Annual Costs	1,695,881 USD

Source: RETScreen Output

3. Financing Structure

The financing structure adopted for Option I is characterized by a debt-to-equity ratio of 70:30. The total debt amount is USD 12.24 million, while equity financing contributes USD 5.25 million. The debt carries an interest rate of 7% with a repayment period of 15 years. Financial evaluation was conducted using a discount rate of 9% and an inflation rate of 2%, both of which are consistent with standard assumptions for long-term infrastructure investments (see Table 7.7). This financing arrangement allows for efficient leverage while maintaining manageable financial risk.

Table 7.7 Option I: Financial structure

Parameter	Value
Debt ratio	70 %
Debt amount	12,243,774 USD
Equity	5,247,332 USD
Debt interest rate	7 %
Debt term	15 years
Discount rate	9 %
Inflation rate	2 %

Source: RETScreen Output

4. Financial Feasibility Indicators

Key financial performance indicators further confirm the high profitability of the project. The pre-tax internal rate of return (IRR) on equity is exceptionally high at 102%, while the pre-tax IRR on assets stands at 32.5%, indicating strong returns even before accounting for taxes. The simple payback period is estimated at 2.7 years, and the equity payback period is only one year, highlighting the project's rapid cost recovery as shown on Table 7.8. A net present value of USD 68.68 million and an annual life-cycle savings of approximately USD 6.5 million underline the long-term economic benefits. Moreover, a benefit–cost ratio of 14.1 and a debt service coverage ratio of 4.9 indicate excellent financial resilience and the ability to comfortably meet debt obligations.

Table 7.8 Option I: Financial feasibility indicators

Indicator	Value
Pre-tax IRR – Equity	102 %
Pre-tax IRR – Assets	32.5 %
Simple payback period	2.7 years
Equity payback period	1 year
Net Present Value (NPV)	68,677,947 USD
Annual life cycle savings	6,499,395 USD/yr
Benefit–Cost (B-C) ratio	14.1

Indicator	Value
Debt service coverage	4.9

Source: RETScreen Output

5. Levelized Cost of Energy (LCOE)

From an energy cost perspective, the levelized cost of energy is estimated at 0.017 USD/kWh, which is significantly lower than the export tariff of 0.06 USD/kWh. This results in a substantial margin of 0.043 USD/kWh, confirming the project’s competitiveness and profitability in the electricity market as shown on Table 7.9.

Table 7.9 Option I: Levelized Cost of Energy (LCOE)

Indicator	USD/kWh
Energy production cost (LCOE)	***0.017***
Electricity export tariff	0.060
Margin above LCOE	***0.043***

Source: RETScreen Output

6. Greenhouse Gas (GHG) Emission Analysis

In terms of environmental performance, Option I delivers considerable greenhouse gas emission reductions. Annual emissions decrease from 36.6 tCO_2 in the base case to 2.6 tCO_2 under the proposed project, representing a reduction of about 93%. This corresponds to an annual reduction of 34 tCO_2 and a cumulative reduction of approximately 1,190 tCO_2 over the project lifetime (see Table 7.10). These savings are equivalent to removing about 6.2 cars or light trucks from use, emphasizing the project’s contribution to climate change mitigation alongside its strong financial performance.

Table 7.10 Option I: Greenhouse gas emission

Item	Value
Base case emissions	36.6 tCO/year
Proposed case emissions	2.6 tCO/year
Annual GHG reduction	34 tCO/year
Emission reduction	93 %
GHG reduction over 35 years	1,190 tCO
Cars and Light Trucks not used	6.2 Vehicles

Item	**Value**
Base case emissions	36.6 tCO/year
Proposed case emissions	2.6 tCO_2$/year

Source: RETScreen Output

7.6.2 Option II – Financial Feasibility and Emission Analysis

1. Project Overview

The financial feasibility and environmental performance of Option II were evaluated using the RETScreen modelling framework, and the results indicate that this hydropower alternative is both economically attractive and environmentally sustainable. The project is based on hydro turbine technology with an installed capacity of 16,840 kW and operates at a capacity factor of 75.4%, demonstrating efficient use of the available hydrological resource. Over its planned operational life of 35 years, the plant is expected to export approximately 111,229 MWh of electricity annually to the national grid. At an electricity export rate of 0.06 USD/kWh, the projected annual revenue is about USD 6.67 million, reflecting a stable income stream and strong market competitiveness as shown on Table 7.11.

Table 7.11 Option II: Project overview

Item	**Value**
Technology	Hydro turbine
Power capacity	16,840 kW
Capacity factor	75.4 %
Project life	35 years
Electricity exported to grid	111,229 MWh
Electricity export rate	0.06 USD/kWh
Electricity export revenue	6,673,732 USD

Source: RETScreen Output

2. Capital and Operating Costs

The capital cost assessment shows that Option II requires a total initial investment of USD 12.63 million, corresponding to a relatively low specific investment cost of 750 USD/kW. This cost structure suggests an efficient project design and favorable construction conditions compared to similar hydropower developments. In terms of operating expenditures, annual operation and maintenance costs are estimated at USD 252,600, which remain modest relative to the scale of energy production. During the first 15 years of operation, annual debt service amounts to USD

970,694, resulting in total annual costs of approximately USD 1.22 million (see Table 7.12). When compared with the projected electricity revenues, these costs indicate a strong operating margin and reinforce the project's financial soundness.

Table 7.12 Option II: Capital and operating cost

Cost component	Value
1. Initial Investment	
Specific Investment Cost	750 USD/kW
Total Initial Cost	12,630,000 USD
2. Annual Cost	
Operation And Maintenance (O&M)	252,600 USD
Debt Service (First 15 Years)	970,694 USD
Total Annual Costs	1,223,294 USD

Source: RETScreen Output

3. Financing Structure

The financing structure of Option II is characterized by a debt ratio of 70%, with debt financing of USD 8.84 million and an equity contribution of USD 3.79 million. The debt is assumed to carry an interest rate of 7% and a repayment period of 15 years. Financial evaluation was conducted using a discount rate of 9% and an inflation rate of 2%, which are consistent with standard assumptions for long-term infrastructure investments (see Table 7.13). This financing arrangement allows for effective leverage while maintaining a balanced risk profile.

Table 7.13 Option II: Financial structure

Parameter	Value
Debt ratio	70 %
Debt amount	8,841,000 USD
Equity	3,789,000 USD
Debt interest rate	7 %
Debt term	15 years
Discount rate	9 %
Inflation rate	2 %

Source: RETScreen Output

4. Financial Feasibility Indicators

Financial performance indicators further confirm the high profitability of the project. The pre-tax internal rate of return on equity is exceptionally high at 150%, while the pre-tax IRR on assets reaches 46.5%, indicating strong returns from both investor and project perspectives (see Table 7.14). The simple payback period is estimated at only two years, and equity payback occurs in less than one year, highlighting rapid capital recovery. The net present value of USD 72.79 million underscores substantial long-term economic benefits, while annual life-cycle savings of approximately USD 6.89 million reflect the project's sustained value generation. In addition, a benefit–cost ratio of 20.2 and a debt service coverage ratio of 6.7 indicate excellent financial resilience and a strong ability to meet debt obligations.

Table 7.14 Option II: Financial feasibility indicators

Indicator	**Value**
Pre-tax IRR – Equity	150 %
Pre-tax IRR – Assets	46.5 %
Simple payback period	2 years
Equity payback period	0.68 years
Net Present Value (NPV)	72,785,345 USD
Annual life-cycle savings	6,888,102 USD/year
Benefit–Cost (B-C) ratio	20.2
Debt service coverage ratio	6.7

Source: RETScreen Output

5. Levelized Cost of Energy (LCOE)

From an energy cost perspective, the levelized cost of energy is estimated at 0.013 USD/kWh, which is significantly lower than the electricity export rate of 0.06 USD/kWh. This results in a substantial margin of 0.047 USD/kWh, confirming the project's high cost efficiency and competitiveness in the electricity market as shown on Table 7.15.

Table 7.15 Option II: Levelized Cost of Energy (LCOE)

Indicator	**USD/kWh**
Energy production cost (LCOE)	***0.013***
Electricity export rate	0.060
Margin above LCOE	***0.047***

Source: RETScreen Output

6. Greenhouse Gas (GHG) Emission Analysis

In environmental terms, Option II delivers significant greenhouse gas emission reductions. Annual emissions decrease from 35.9 tCO_2 in the baseline scenario to 2.5 tCO_2 under the proposed project, representing a reduction of approximately 93%. This corresponds to an annual reduction of 33.4 tCO_2 and a cumulative reduction of about 1,168 tCO_2 over the 35-year project life as shown on Table 7.16. These emission savings are equivalent to removing approximately 6.1 cars or light trucks from use, highlighting the project’s meaningful contribution to climate change mitigation and sustainable energy development in Ethiopia.

Table 7.16 Option II: Greenhouse gas emission

Item	Value
Country	Ethiopia
Baseline emissions	35.9 tCO/year
Proposed case emissions	2.5 tCO/year
Annual GHG reduction	33.4 tCO/year
Emission reduction	93 %
GHG reduction over 35 years	1,168 tCO
Cars and Light Trucks not used	6.1 Vehicles
Baseline emissions	35.9 tCO/year

Source: RETScreen Output

7.6.3 Option III – Financial Feasibility and Emission Analysis

1. Project Overview

The financial feasibility and environmental performance of Option III were assessed using the RETScreen modeling platform, focusing on a small-scale hydropower development designed to complement larger generation options. The project is based on a single hydropower turbine with an installed capacity of 209 kW and an exceptionally high capacity factor of 95%, indicating near-continuous operation and efficient utilization of the available water resource. Over a project life of 35 years, the plant is expected to export approximately 1,739 MWh of electricity annually to the national grid. With an electricity export tariff of 0.06 USD/kWh, the annual revenue generated from power sales is estimated at USD 104,358, reflecting a modest but stable income stream consistent with the project’s limited scale as shown on Table 7.17.

Table 7.17 Option III: Project overview

Item	Value
Technology	Hydropower (1 turbine)
Installed capacity	209 kW
Capacity factor	95 %
Project life	35 years
Electricity exported to grid	1,739 MWh/year
Electricity export tariff	0.06 USD/kWh
Annual electricity revenue	104,358 USD

Source: RETScreen Output

2. Capital and Operating Costs

The capital cost analysis shows that Option III requires a total initial investment of USD 627,418, corresponding to a relatively high specific investment cost of 3,002 USD/kW. This elevated unit cost is typical for small-scale hydropower projects, where fixed civil and electro-mechanical costs are distributed over a much smaller installed capacity. Annual operating expenditures are comparatively low, with operation and maintenance costs estimated at USD 12,540 per year. In addition, annual debt service during the first 15 years of operation amounts to USD 48,221, resulting in total annual costs of approximately USD 60,761 (see Table 7.18). When compared to annual electricity revenues, these costs suggest that the project can cover its obligations while maintaining a positive operating margin.

Table 7.18 Option III: Capital and operating costs

Cost component	Value
Initial Investment	
Specific Investment Cost	3,002 USD/kW
Total Initial Cost	627,418 USD
Annual Cost	
Operation and Maintenance (O&M)	12,540 USD
Debt Service (First 15 Years)	48,221 USD
Total Annual Costs	60,761 USD

Source: RETScreen Output

3. Financing Structure

The financing structure adopted for Option III follows a conventional approach, with a debt ratio of 70% and equity contributing the remaining 30% of the total investment. This corresponds to a debt amount of USD 439,193 and an equity contribution of USD 188,225 as shown on Table 7.19. The loan is assumed to carry an interest rate of 7% and a repayment period of 15 years. Financial evaluation was undertaken using a discount rate of 9% and an inflation rate of 2%, which are standard assumptions for long-term energy infrastructure projects. This structure allows the project to benefit from financial leverage while maintaining manageable repayment commitments.

Table 7.19 Option III: Financial structure

Parameter	Value
Debt ratio	70 %
Debt amount	439,193 USD
Equity	188,225 USD
Interest rate	7 %
Loan term	15 years
Discount rate	9 %
Inflation rate	2 %

Source: RETScreen Output

4. Financial Feasibility Indicators

Financial feasibility indicators indicate moderate but acceptable economic performance. The pre-tax internal rate of return on assets is estimated at 11.2%, which slightly exceeds the assumed discount rate, suggesting that the project is economically viable, though less attractive than larger-scale alternatives. The simple payback period is estimated at 6.8 years, while equity payback occurs within approximately 3.9 years, reflecting a longer capital recovery period relative to medium-scale hydropower options (see Table 7.20). The net present value of USD 629,927 remains positive, confirming that the project generates net economic benefits over its lifetime. Annual life-cycle savings are estimated at USD 59,614, and a benefit–cost ratio of 4.3 indicates that the benefits substantially outweigh the costs. A debt service coverage ratio of 1.9 further suggests that the project maintains an adequate capacity to meet its debt obligations.

Table 7.20 Option III: Financial feasibility indicators

Indicator	Value
Pre-tax IRR – Assets	11.2 %
Simple payback period	6.8 years
Equity payback period	3.9 years
Net Present Value (NPV)	629,927 USD
Annual life-cycle savings	59,614 USD/year
Benefit–Cost (B-C) ratio	4.3
Debt service coverage	1.9
Pre-tax IRR – Assets	11.2 %

Source: RETScreen Output

5. Levelized Cost of Energy (LCOE)

From an energy cost perspective, the levelized cost of energy is estimated at 0.04 USD/kWh, which remains below the electricity export tariff of 0.06 USD/kWh. This results in a positive margin of 0.02 USD/kWh, indicating that electricity generation under Option III is economically competitive, albeit with a narrower margin compared to larger hydropower schemes as shown on Table 7.21.

Table 7.21 Option III: Levelized Cost of Energy (LCOE)

Indicator	USD/kWh
Energy production cost (LCOE)	***0.04***
Electricity export tariff	0.06
Margin above LCOE	***0.02***

Source: RETScreen Output

6. Greenhouse Gas (GHG) Emission Analysis

In environmental terms, Option III contributes to greenhouse gas emission reductions, despite its relatively small scale. Annual emissions decline from 0.56 tCO_2 in the baseline scenario to 0.04 tCO_2 under the proposed project, representing a reduction of approximately 93%. This corresponds to an annual reduction of about 0.52 tCO_2 and a cumulative reduction of roughly 18 tCO_2 over the 35-year project life (see Table 7.22). While modest in absolute terms, these reductions are equivalent to removing approximately 0.1 vehicles from operation and underscore the project's role in supporting low-carbon energy development in Ethiopia.

Table 7.22 Option III: Greenhouse gas emission

Item	Value
Country	Ethiopia
Baseline emissions	0.56 tCO/year
Proposed case emissions	0.04 tCO/year
Annual GHG reduction	0.52 tCO/year
Emission reduction (%)	93 %
GHG reduction over 35 years	18 tCO
Cars and Light Trucks not used	0.1 Vehicles

Source: RETScreen Output

CHAPTER EIGHT

COMPARISON ANALYSIS AND DISCUSSION

8.1 Introduction

This chapter presents a comprehensive comparative analysis and discussion of the Tendaho Dam hydropower retrofit study, focusing on technical, economic, and cost-competitiveness aspects of the proposed retrofit options. Furthermore, the chapter contextualizes the Tendaho findings within established literature and international benchmarks, demonstrating alignment with global best practices in hydropower retrofitting.

8.2 Comparative Analysis

The comparative assessment of the three hydropower retrofit options for the Tendaho Dam highlights substantial differences in technical scale, financial outcomes, cost efficiency, and environmental benefits. Although all options demonstrate the potential to generate electricity from the existing dam infrastructure, their overall contributions and performance levels vary significantly when evaluated against the indicators presented in the table.

In terms of technical performance, Options I and II are characterized by large installed capacities of 17,579 kW and 16,840 kW, respectively, while Option III is considerably smaller at 209 kW. This difference in installed capacity is directly reflected in annual electricity generation. Option I produces 113,338 MWh per year, marginally exceeding Option II's output of 111,229 MWh per year. In contrast, Option III generates only 1,739 MWh annually, indicating a limited role in meeting broader energy demand. Capacity factor values further clarify operational characteristics as shown on Table 8.1. Option III records the highest capacity factor at 95%, suggesting near-continuous utilization of available water resources. Options I and II achieve capacity factors of 73.6% and 75.4%, which, although lower than Option III, remain strong and appropriate for large-scale hydropower operation. These results indicate that while Option III is operationally efficient in relative terms, Options I and II deliver far greater absolute energy output.

Revenue performance follows a similar pattern, as all options operate under an identical electricity export tariff of 0.06 USD/kWh. Consequently, differences in annual revenue arise solely from variations in electricity generation. Option I achieves the highest annual revenue at USD

6,800,288, closely followed by Option II with USD 6,673,732. Option III generates a much lower annual revenue of USD 104,358, reflecting its limited generation capacity. This contrast underscores the importance of project scale in achieving meaningful revenue from hydropower retrofits.

Capital investment requirements reveal notable differences in cost structure. Option I requires the highest total initial investment of USD 17,491,105, while Option II requires a lower investment of USD 12,630,000. Option III involves a substantially smaller total cost of USD 627,418. However, when assessed using specific investment cost, Option II emerges as the most cost-efficient option at USD 750 per kW, compared to USD 995 per kW for Option I. Option III records the highest specific investment cost at USD 3,002 per kW, indicating lower cost efficiency despite its small total capital requirement. These figures suggest that Option II achieves a more favorable balance between capacity and investment efficiency (see Table 8.1).

Financial feasibility indicators further strengthen this distinction. Option II records the highest net present value of USD 72,785,345, exceeding Option I's NPV of USD 68,677,947. Option III's NPV is substantially lower at USD 629,927, indicating limited long-term financial contribution. A similar pattern is observed in pre-tax internal rates of return on assets, where Option II achieves the highest value at 46.5%, followed by Option I at 32.5%, and Option III at 11.2%. Benefit–cost ratios reinforce these findings, with Option II recording the highest ratio of 20.2, compared to 14.1 for Option I and 4.3 for Option III. These results indicate that Option II delivers the strongest economic return relative to its costs.

Debt service coverage ratios provide further insight into financial robustness. Option II exhibits the highest DSCR at 6.7, indicating a strong ability to meet debt obligations. Option I also demonstrates solid financial resilience with a DSCR of 4.9. Option III, with a DSCR of 1.9, shows a much narrower margin for debt servicing, suggesting higher financial risk relative to the other options (see Table 8.1).

Energy cost competitiveness is a key criterion in hydropower evaluation. Option II achieves the lowest levelized cost of energy at 0.013 USD/kWh, followed by Option I at 0.017 USD/kWh. Option III records a higher LCOE of 0.04 USD/kWh. The margin above LCOE further differentiates performance, with Option II achieving the highest margin of 0.047 USD/kWh, slightly above Option I's margin of 0.043 USD/kWh, while Option III records a lower margin of 0.02 USD/kWh as shown on Table 8.1. These values indicate that Options I and II provide stronger economic buffers against cost variability.

Table 8.1 Comparative Evaluation of Options I, II & III

Criterion	**Indicator**	**Option I**	**Option II**	**Option III**
Technical Performance	Installed capacity (kW)	17,579	16,840	209
	Capacity factor (%)	73.6	75.4	95
	Annual electricity generation (MWh/year)	113,338	111,229	1,739
Revenue Potential	Electricity export tariff (USD/kWh)	0.06	0.06	0.06
	Annual electricity revenue (USD/year)	6,800,288	6,673,732	104,358
Capital Investment	Specific investment cost (USD/kW)	995	750	3,002
	Total initial cost (USD)	17,491,105	12,630,000	627,418
Financial Feasibility	NPV (USD)	68,677,947	72,785,345	629,927
	Pre-tax IRR – Assets (%)	32.5	46.5	11.2
	Benefit–Cost ratio	14.1	20.2	4.3
	Debt service coverage ratio	4.9	6.7	1.9
Energy Cost Competitiveness	LCOE (USD/kWh)	0.017	0.013	0.04
	Margin above LCOE (USD/kWh)	0.043	0.047	0.02
Environmental Performance	Baseline emissions (tCO_2/year)	36.6	35.9	0.56
	Proposed case emissions (tCO_2/year)	2.6	2.5	0.04
	Annual GHG reduction (tCO_2/year)	34.0	33.4	0.52
	Emission reduction (%)	93	93	93

Lifetime GHG reduction (tCO$_2$)	1,190	1,168	18

As Table 8.1 depicts environmental performances of all options achieve substantial emission reductions. Options I and II reduce emissions by 34.0 tCO$_2$/year and 33.4 tCO$_2$/year, respectively, while Option III achieves a smaller reduction of 0.52 tCO$_2$/year. All options report an emission reduction rate of 93%. Over the project lifetime, Options I and II achieve large cumulative reductions of 1,190 tCO$_2$ and 1,168 tCO$_2$, respectively, compared to 18 tCO$_2$ for Option III .

Overall, the comparison demonstrates that Option II consistently offers the most balanced and robust performance across technical, financial, economic, and environmental criteria. Option I performs strongly but is constrained by higher investment requirements, while Option III, despite high operational efficiency, remains limited in scale and overall impact.

8.3 Discussion

The primary research question of this study is: *To what extent can the existing Tendaho Dam infrastructure be technically retrofitted to enhance its power and energy generation capacity while maintaining full compliance with established irrigation flow requirements?* The findings indicate that retrofitting the Tendaho Dam is technically feasible and can deliver substantial power and energy generation without compromising irrigation obligations. Specifically, the study's retrofit options demonstrate that both Options I and II can achieve installed capacities exceeding 16 MW and annual generation greater than 111,000 MWh. These results confirm that the structural and hydraulic characteristics of the existing dam can accommodate additional power generation facilities while preserving its primary irrigation function.

This technical feasibility aligns with broader evidence on retrofitting non-powered dams. Shrestha (2022) emphasizes that turbine installation and operational planning in existing reservoirs can enable hydropower development while safeguarding original water distribution functions. Similarly, a case study on non-powered dams in the Büyük Menderes River basin confirms that maintaining existing outflow regimes is essential for assessing retrofit potential, with technical simulations ensuring power generation does not compromise water delivery for primary uses (Investigation of the Hydroelectric Development Potential of Non-powered Dams, 2024). At Tendaho, both Options I and II are designed to adhere to existing discharge profiles, demonstrating compatibility with these principles. Further, advanced hydraulic modelling, as applied in other complex flow systems, strengthens confidence that retrofitted infrastructure can operate safely while integrating hydropower functions (Demeke, Asfaw & Shiferaw, 2019).

The second research question examines: *What engineering alternatives are available for the Tendaho Dam project that can improve Net Present Value (NPV) and support recovery of the sunk investment cost?* The study findings indicate that engineering choices substantially influence financial performance, particularly through capital efficiency, energy output, and long-term revenue stability. Among the options analyzed, Option II achieves the highest NPV, followed closely by Option I, while Option III delivers only marginal positive returns. This performance reflects differences in engineering scale and cost efficiency rather than tariff conditions, which remain uniform across options.

Options I and II align with recognized hydropower retrofit strategies that optimize existing infrastructure to enhance economic performance. Rahi and Chandel (2015) note that refurbishment and uprating of existing hydropower facilities can yield high NPV by exploiting civil infrastructure while avoiding new dam construction costs. Freibott et al. (2024) further confirm that retrofitting appropriately scaled hydropower systems improves project NPV by converting previously sunk infrastructure costs into productive assets, consistent with the higher installed capacities and energy outputs achieved under Tendaho's Options I and II. In contrast, Option III demonstrates the limitations of small-scale retrofits, which generate insufficient revenue to significantly recover sunk costs. System-level planning studies also support these findings, as optimized designs within broader energy frameworks improve NPV and financial resilience (Kuriqi et al., 2022). Additionally, Option II illustrates that combining low specific investment cost with strong energy output maximizes NPV, confirming that engineering alternatives emphasizing capacity optimization and integration with existing infrastructure are critical for economic viability (Okang et al., 2023).

The third research question asks: *Can the proposed hydropower retrofit options at the Tendaho Dam reduce the Levelized Cost of Energy (LCOE) to within the 0.01–0.05 USD/kWh benchmark established by IRENA?* The study demonstrates that all proposed options achieve this target, with Options I and II performing particularly well. Option I achieves an LCOE of 0.017 USD/kWh, while Option II attains an even lower 0.013 USD/kWh. Option III, at 0.04 USD/kWh, remains within the benchmark but approaches its upper threshold.

These outcomes are consistent with international findings. IRENA (2012) reports that hydropower retrofits using existing infrastructure commonly achieve LCOE values between 0.01 and 0.05 USD/kWh, reflecting the cost advantage of leveraging pre-existing civil works. More recent assessments confirm that hydropower remains one of the most cost-competitive renewable technologies globally, with weighted average LCOE values below 0.05 USD/kWh (IRENA, 2023). The Tendaho results illustrate that large-scale, optimized retrofit designs, as in Options I and II, effectively meet cost-competitiveness targets while maximizing the value of sunk infrastructure investments.

The fourth research question investigates: *Which financial modelling approach best demonstrates the economic advantage of the Tendaho Dam hydropower retrofit relative to prevailing high national LCOE, while meeting IRENA's criteria for small-scale hydropower?* The findings indicate that a discounted cash flow (DCF)–based framework, integrating NPV, Internal Rate of Return (IRR), and LCOE, effectively captures the economic benefits of the proposed retrofit options. This approach allows long-term project benefits to be evaluated against capital and operating costs, which is particularly relevant in contexts with high national generation costs.

The literature supports this approach. IRENA (2012) recommends combining LCOE with NPV and IRR to reflect project profitability fully, particularly for small-scale hydropower. Similarly, the World Bank (2019) highlights that DCF models are essential for retrofit evaluations as they account for the time value of money and incremental benefits of existing infrastructure. Kougias et al. (2019) further emphasize that integrating LCOE benchmarking with NPV-based financial analysis provides a robust method for demonstrating economic advantage relative to higher national generation costs. At Tendaho, this integrated framework demonstrates that Options I and II are economically competitive, while Option III, though technically viable, provides comparatively lower financial returns.

Overall, the discussion confirms that the Tendaho Dam can be technically retrofitted to enhance power and energy generation while maintaining full compliance with irrigation requirements. Options I and II consistently outperform Option III across technical, economic, and cost-competitiveness criteria, reflecting optimal engineering design, efficient capital use, and effective integration with existing infrastructure. The study aligns closely with international literature on hydropower retrofitting, highlighting that multipurpose reservoirs can achieve both energy generation and water resource objectives without compromising established functions. By adopting well-optimized retrofit strategies and employing robust financial modelling, the Tendaho Dam project demonstrates the practical, economic, and technical feasibility of upgrading non-powered dams for renewable energy production.

CHAPTER NINE

SUMMARY OF MAJOR FINDINGS, CONCLUSION AND RECOMMENDATIONS

9.1 Introduction

This chapter provides a concise overview of major findings, conclusions, and recommendations based on the technical, economic, and cost-competitiveness analyses of the proposed retrofit options.

9.2 Summary of Major Findings

The findings indicate that retrofitting the Tendaho Dam is technically feasible. Option I and Option II each achieve installed capacities exceeding 16 MW and annual energy generation over 111,000 MWh, demonstrating that the dam's structural and hydraulic systems can accommodate additional power generation without compromising irrigation obligations. Option III, while smaller in scale, still provides a technically viable solution, highlighting the potential for incremental retrofits.

The study demonstrates that engineering choices significantly influence economic outcomes. Option II yields the highest NPV, followed by Option I, reflecting effective capital utilization and higher energy output. Option III delivers only marginal positive NPV due to its smaller scale. The results are consistent with established hydropower retrofit practices that emphasize capacity optimization and efficient turbine selection to enhance financial performance. By exploiting existing civil infrastructure, Options I and II demonstrate how retrofit designs can convert sunk costs into productive assets, while Option III illustrates the limitations of low-scale retrofits in generating significant economic returns.

The study findings confirm that all options meet this benchmark. Option I achieves an LCOE of 0.017 USD/kWh, Option II achieves 0.013 USD/kWh, and Option III achieves 0.04 USD/kWh. The lower LCOE values of Options I and II highlight the cost efficiency achieved by leveraging existing infrastructure and implementing large-scale, well-optimized retrofits. Option III, although within the benchmark, demonstrates that smaller-scale retrofits are less cost-efficient but still feasible.

The study shows that a discounted cash flow (DCF)–based framework, integrating NPV, IRR, and LCOE, effectively captures the economic advantage of the retrofit options. Options I and II clearly demonstrate superior economic competitiveness, whereas Option III, despite technical feasibility, offers lower financial returns.

Overall, the major findings indicate that retrofitting the Tendaho Dam is technically, economically, and cost-effectively viable. Options I and II consistently outperform Option III across all parameters, including installed capacity, energy generation, NPV, and LCOE, while maintaining irrigation compliance. The study confirms that optimized retrofitting strategies can effectively leverage existing infrastructure to enhance renewable energy production, demonstrating the practical and strategic value of upgrading non-powered dams for multipurpose use.

9.3 Conclusions

The study concludes that the existing Tendaho Dam infrastructure can be effectively retrofitted to enhance hydropower generation while maintaining full compliance with established irrigation flow requirements. The technical assessment demonstrates that Options I and II offer substantial installed capacities exceeding 16 MW and annual generation surpassing 111,000 MWh, confirming the structural and hydraulic suitability of the dam for additional power facilities. Option III, although smaller in scale, remains technically viable, indicating that incremental retrofitting is also feasible.

From an economic perspective, the study highlights that engineering alternatives significantly influence financial outcomes. Option II achieves the highest Net Present Value (NPV), followed by Option I, reflecting optimal utilization of existing infrastructure and efficient turbine selection. Option III, despite lower capital requirements, delivers only marginal positive NPV, underscoring the limitations of small-scale retrofits in recovering sunk investment costs. The findings align with established literature emphasizing that capacity optimization and cost-efficient retrofitting strategies enhance economic performance and transform previously unproductive assets into revenue-generating infrastructure.

In terms of cost competitiveness, all proposed retrofit options achieve Levelized Cost of Energy (LCOE) within the 0.01–0.05 USD/kWh benchmark established by IRENA. Options I and II, with LCOE values of 0.017 and 0.013 USD/kWh respectively, demonstrate superior efficiency and competitiveness, whereas Option III, at 0.04 USD/kWh, remains feasible but less optimal. The study further confirms that an integrated discounted cash flow (DCF)–based financial modeling framework, incorporating NPV, IRR, and LCOE, effectively captures the economic advantages of the retrofit options, particularly under high national generation cost scenarios.

Overall, the research concludes that optimized retrofitting of the Tendaho Dam represents a technically, economically, and financially viable strategy to enhance renewable energy production. Options I and II consistently outperform Option III across technical, economic, and cost-efficiency measures, offering a robust and sustainable pathway for multipurpose water resource utilization and renewable energy development.

9.4 Technical Specifications (Option II)

Based on your design framework, the following technical standards must be met to ensure operational compatibility with irrigation requirements.

A. Turbine and Generator System

- Turbine Type: Low-head, double-regulated Kaplan turbines.
- Configuration: Two (2) units to allow for operational flexibility and maintenance without full plant shutdown.
- Total Installed Capacity: 16,840 kW.
- Design Efficiency: Units must maintain high efficiency across variable flow ranges to ensure "run-of-river" performance following irrigation schedules.

B. Hydraulic and Civil Structures

- Bifurcation Design: The shared penstock must be integrated into the existing irrigation tunnel without compromising the structural integrity of the dam or the capacity of irrigation releases.
- Penstock Diameter: Sized at 4.25m for Option II to optimize flow velocity and minimize head losses.
- Powerhouse Dimensions: A reinforced concrete structure with a footprint of approximately 25m (width) by 24.3m (length) and a height of 13m to accommodate crane operations for generator rotor lifting.

- Tailrace: A dedicated channel designed to return all turbinated water immediately back to the irrigation system or the Awash River, ensuring zero net loss to the "Water-Energy-Food" nexus.

C. Operational Integration

- Priority Rule: Hydropower generation must remain subordinate to the mandated irrigation flow regime for sugarcane estates and local communities.
- Control System: Must include automated governors capable of adjusting to the 10-day reservoir simulation releases and irrigation demand patterns.

D-No Priced BOQ

Item No.	**Description of Work / Equipment**	**Unit**	**Estimated Quantity**	**Summary Cost (USD)**
1	**Civil Works**			
1.1	Powerhouse Construction (25mx24.3mx13m)	LS	1	
1.2	Tailrace Channel Construction	LS	1	
1.3	Abutment Excavation at Dam Toe	m^3	21,250	
2	**Hydro-Mechanical Equipment**			
2.1	Bifurcation Piece & Connection Works	LS	1	
2.2	Penstock (D = 4.25m)	Lump sum	1	
3	**Electro-Mechanical Equipment**			
3.1	Kaplan Turbine Units (Double Regulated)	Set	2	
3.2	Synchronous Generators	Set	2	
3.3	Control Bay & Electrical Systems	LS	1	
Total	**Estimated Initial Investment (Option II)**			

9.5 Recommendations

Based on the findings of this study, several recommendations are proposed to guide the successful implementation of hydropower retrofitting at Tendaho Dam while ensuring sustainable and efficient utilization of water resources. The recommendations address technical, economic, operational, and policy considerations, providing a comprehensive framework for decision-making and future development.

- The study demonstrates that Options I and II consistently outperform Option III in terms of installed capacity, annual energy generation, Net Present Value (NPV), and Levelized Cost of Energy (LCOE). Therefore, it is recommended that project planners and stakeholders prioritize the implementation of large-scale retrofit strategies, either the Dedicated Waterway Strategy (Option I) or the Bifurcation Strategy (Option II). These options not only maximize energy output but also leverage existing infrastructure efficiently, reducing the need for extensive new civil works and minimizing capital expenditure relative to expected returns. Option III, although technically feasible, is less economically attractive and should only be considered as a supplementary or incremental approach when budget constraints or phased implementation is necessary.
- Ensuring that retrofitting interventions do not compromise the dam's primary function of irrigation is critical. Operational rules should be carefully designed to coordinate hydropower generation with irrigation releases, particularly during low-flow periods. Advanced flow control mechanisms, such as automated gates and real-time monitoring systems, are recommended to optimize water allocation between energy and agricultural needs. This will safeguard crop production and maintain the reliability of the irrigation network, reinforcing the multipurpose functionality of Tendaho Dam.
- Technical performance is strongly influenced by the choice of turbines and the hydraulic design of penstocks and waterways. The study emphasizes that turbine efficiency and site-specific head and flow conditions must guide the selection process. It is recommended to conduct detailed hydraulic modelling during the design phase to minimize energy losses, optimize power output, and ensure structural compatibility. Incorporating flexibility in

turbine operation can also enhance adaptability to seasonal flow variations and peak electricity demand.

- Economic analysis indicates that large-scale retrofits deliver superior financial returns and cost efficiency. It is therefore recommended to employ a robust financial planning framework, incorporating Net Present Value, Internal Rate of Return, and Levelized Cost of Energy, to guide investment decisions. Opportunities for funding through public-private partnerships, renewable energy incentives, and concessional financing should be explored to reduce upfront capital constraints and attract private sector participation. Regular economic reassessment should be performed throughout the project lifecycle to address changes in energy prices, operating costs, and policy environments.
- A long-term monitoring and maintenance program is essential to sustain technical performance and extend the operational life of retrofitted infrastructure. Routine inspections of mechanical components, hydraulic structures, and electrical systems should be conducted, with rapid response protocols for fault detection and repairs. Capacity-building initiatives for local engineers and operators are recommended to ensure knowledge transfer and operational resilience.
- Successful retrofitting requires alignment with national energy policy and institutional support. It is recommended that the Ministry of Water and Energy, along with local authorities, establish clear regulatory frameworks, performance standards, and incentives for renewable energy integration. Coordination among stakeholders, including irrigation authorities, energy utilities, and local communities, is essential to achieve shared objectives and mitigate potential conflicts between energy generation and agricultural water use.

In conclusion, the Tendaho Dam retrofitting project represents a technically and economically viable opportunity to enhance renewable energy production while maintaining irrigation functions. Prioritizing large-scale retrofit options, optimizing turbine and hydraulic design, ensuring irrigation compliance, and implementing robust financial, monitoring, and policy measures will maximize the long-term benefits of the project. These recommendations provide a strategic roadmap for transforming Tendaho Dam into a multipurpose, sustainable energy and water resource asset.

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