Project Financing of New Hydropower Development at Existing Non-Powered Dams

Lessons learned from case studies in the past 10 years and suggestions for improving future hydropower project economics

National Hydropower Association – Spring 2021 Research Fellowship
Diego Antonio Guerrero – dag285@cornell.edu

Diego Antonio Guerrero
National Hydropower Association Research Fellow

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Diego Antonio Guerrero
National Hydropower Association Research Fellow

Acknowledgements

Thank you to Adam Ward (American Municipal Power), Ryan Berg (Enel Green Power), Scott Hofmeister (Hull Street Energy), Tom Heller (MRES), Paul Jacob & Erik Steimle (Rye Development), Dennis Cakert (National Hydropower Association), my co-research fellows (Connor Bevan, Arianna Drechsler, Brian Ziegler) and others for their insight, guidance and support in this paper and research fellowship.

Diego Antonio Guerrero
National Hydropower Association Research Fellow

Executive Summary

The United States has a large untapped market opportunity in financing new hydropower development at existing non-powered dams (NPDs). The nation has over 80,000 dams that were built exclusively for non-energy purposes and currently lack hydropower-generating equipment.[1] Retrofitting existing dam infrastructure can build additional capacity for non-intermittent renewable hydropower to communities with high-energy demand.[2] Many of the fixed capital costs and environmental impacts of construction have already been incurred, thus reducing the technological and business risks associated with new dam construction. Yet, investors are still hesitant to finance NPD electrification projects due to a lack of financial literature on project valuation and economics, a lengthy and complex regulatory process that leads to project uncertainty, and minimal state and federal support to stimulate development and financing.

In this paper, we provide a review of project financing trends, market drivers, and challenges facing NPD electrification through case studies of fifteen NPD retrofit projects over the past ten years. The size, location, development strategy, project developer(s), and power purchase agreement determined whether the projects could secure financing through private equity, public or private debt, commercial lending, grants, or a combination of the available funding options. The projects all faced similar challenges in terms of regulatory complexities and indeterminate development timelines yet powered through those hurdles to realize the financial, economic and environmental benefits of hydropower to their communities.

This paper recommends developers to pursue the following strategies to improve future NPD project economics: (i) cluster small projects into a single portfolio to achieve economies of scale and improve bankability for low-cost financing, (ii) strategically position these portfolios in locations near potential off-takers and consumers interested in clean energy and (iii) disclose investment details in the form of financial literature to increase investor awareness of this traditionally underserved sector. The paper also recommends the federal, state and local government to adopt policies that (i) focus on modernizing and streamlining the NPD licensing and permitting process, (ii) expand/extend current tax credits on renewable energy development, (iii) invest in modernizing current dam infrastructure, (iv) preserve tax-advantaged and subsidized financial instruments used for project finance, and (v) introduce green banks to add depth to existing green project financing markets.

By executing these recommendations and capitalizing on recent NPD interest from institutional and retail investors in the public debt markets as well as infrastructure investment firms such as Brookfield Renewable and Climate Adaptive Infrastructure, NPD project financing can eventually become inexpensive, expeditious and commonplace across the nation.

[1] https://www.osti.gov/servlets/purl/1470870
[2] https://www.energy.gov/eere/articles/5-promising-water-power-technologies

A. Market Background for Non-Powered Dams ("NPDs")

The U.S. has over 80,000 existing dams, of which less than 2,500 produce hydropower, as most are used solely for navigational and water management purposes and lack electricity-generating equipment.[1] These non-powered dams ("NPDs"), if retrofitted with hydroelectric power plants and facilities, can generate approximately 12GW of low-carbon electricity and increase the national hydropower capacity by 15%.[3] The majority of potential high-energy NPDs are located along the Mississippi river and its major tributaries (Arkansas, Missouri, Ohio, Red rivers), which are home to large population centers of the South and Midwest.[4] NPD electrification can supply non-intermittent, low-carbon renewable energy to these populaces with high energy-demand.

NPD electrification presents an attractive market opportunity as it forgoes the capital intensity of new dam construction by making use of existing waterway infrastructure while minimizing impacts to natural habitats and wilderness areas.[1] NPD projects leverage abundant, unused dam works and lock structures to minimize excavation and construction activities and reduce civil costs. These projects accordingly face lower technological complexities, business risks and capital costs compared with greenfield dam construction.

Hydropower in itself provides pure generating capacity as well as essential grid reliability and power stability services compared to other intermittent sources of renewable energy such as wind and solar.[5] New hydropower generating capacity can spur economic activity in areas of local development, diversify power portfolios with clean energy, and in the case of NPDs, attract much-needed investment into the nation's aging dam infrastructure and its ongoing maintenance.

Despite these opportunities, growth in hydroelectric generation capacity, particularly across NPDs, has been relatively modest across the U.S.[6] NPD electrification has historically experienced financing challenges due to lengthy permitting and licensing processes, prolonged development timelines from inception to operation, lack of investor knowledge, and other project development risks.[7]

The majority of NPDs that are best suited for hydropower development are owned and operated by the U.S. Army Corps of Engineers ("USACE") and the Bureau of Reclamation. These agencies require unique regulatory approvals that can extend up to a decade, making investing in NPDs financially risky. Thus, it can oftentimes be challenging to secure project financing to fund licensing, development and construction for NPD electrification projects.

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[3] https://www.seforall.org/sites/default/files/powerofriversreport_final1.pdf
[4] https://www.energy.gov/sites/prod/files/2013/12/f5/npd_report_0.pdf
[5] https://www.hydro.org/wp-content/uploads/2017/08/MODERNIZING-ENERGY-INFRASTRUCTURE-CHALLENGES-AND-OPPORTUNITIES-TO-EXPANDING-SwaminathanR-20170315-U1.pdf
[6] https://insights.globalspec.com/article/11904/dams-could-add-hundreds-of-megawatts-to-nation-s-electric-grid
[7] https://info.ornl.gov/sites/publications/files/Pub56556.pdf

B. Licensing Process Poses Challenges for Project Financing

To initiate construction of an NPD hydropower retrofit project, a developer must first complete a licensing process managed by the Federal Energy Regulatory Commission ("FERC").[1] The goal of this process is to obtain an original FERC license for generation, with terms and conditions for operations negotiated among various stakeholder groups and established following an environmental assessment.

Extensive requirements are in place for obtaining the licenses and approvals necessary for constructing or modifying a FERC-jurisdictional hydroelectric project.[8] No other generation source, except nuclear power, bears a comparable regulatory burden. Developers must also obtain permits and approvals from the dam owners (USACE or Bureau of Reclamation), state, environmental agencies, jurisdictional district, and municipalities among others. The licensing and permitting process can take anywhere from five to over ten years. Such a protracted and uncertain regulatory process hampers investment by increasing regulatory, financial and implementation risks, thus driving up the cost of new hydropower development at existing dams.[9] Licensing and permitting costs can be as much as 25-30% of the overall project cost.

Renewal of a FERC license ("relicensing") also involves a multi-year process that can approach the time required for the original license.[10] Owners must obtain multiple approvals from other federal, state and local authorities similar to the original licensing process. Efforts have been raised to simplify and streamline these processes to mitigate financial risks and provide developers and investors with added certainty. Regardless, there are inherent regulatory complexities because of the multiple interests involved.

The following reasons summarize the regulatory issues investors face when considering making an investment to an NPD electrification project:

- **High regulatory costs**: The regulatory process requires developers to pay fees to obtain each individual license, regulatory approval and supporting environmental review.[9]
- **Delayed income stream**: Lengthy regulatory process can delay revenue source and recapture on the investment for several years.[9]
- **Significant short-term risks**: It is challenging for developers to find investors who are willing to invest in hydropower due to the aforementioned high costs, regulatory risks and delayed return on investment. While investors consider the merits of hydropower such as low fuel costs and low operational costs over time, investors also weigh the short term risks heavily in their investment decision-making process.[9]

8 https://www.cedengineering.com/userfiles/Hydropower%20-%20The%20Largest%20Source%20of%20Renewable%20Energy%20R1.pdf

9 https://docs.house.gov/meetings/IF/IF03/20160202/104387/HHRG-114-IF03-20160202-SD005.pdf

10 https://www.academia.edu/43964221/Renewable_Electricity_Futures_Study_Volume_2_Renewable_Electricity_Generation_and_Storage_Technologies

- **Difficulty securing power purchase agreements ("PPA")**: To obtain project financing from debt and equity investors, the NPD developer must first acquire a PPA, a sales contract between the developer and the off-taker (the party purchasing the power generated from the hydroelectric facility).[11] These sales contracts secure the revenue streams used to service the project's financing, maintenance and operations. The off-taker can include anyone from independent power producers, investor owned utilities and public power entities (as explained in the next section) to cities, municipalities, corporations, and universities. Regulatory uncertainty and the ever-present risk of project delays make it difficult for potential off-takers to pursue PPAs for uncertain projects.[9] Any contracting third party would demand assurances as to when the project will actually get built and when it expects to receive generated power. Failure to obtain a PPA inhibits the developer's ability to obtain project financing, which in turn can terminate the entire NPD retrofit project.

C. Project Developers & Investment Criteria

Hydropower projects such as NPD electrification attract a variety of project developers and participants each with their own set of investment philosophies and criteria.[12]

- **Independent Power Producers ("IPPs")** are non-regulated, privately owned entities that operate power facilities to generate electricity for sale.[11] IPPs tend to be smaller than other publicly- or government-owned utility firms, with smaller balance sheets and limited access to low-cost, tax-advantaged financial instruments to finance infrastructure projects. As such, IPPs typically seek short-term, quick payback, low capacity hydropower projects financed by non-recourse bank debt (loans secured by collateral) and high-cost equity.[13] Non-utility, small-scale hydropower developers typically share the same investment criteria as these IPPs, such as Nelson Energy, the original developer of the Red Rock Hydroelectric Project (as discussed in its case study later in this paper).
- **Investor Owned Utilities ("IOUs")** are publicly owned electric distributors that issue stock to shareholders and are subject to state and federal rate regulation.[11] IOUs take a longer-term perspective on projects and can internalize the benefits of hydropower to their power systems with lower rates of return than IPPs.[13] IOUs can capture these lower returns as their projects are corporate-financed, leveraging their robust balance sheets with payback guaranteed through revenue from its customer rate base.

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[11] http://hummedia.manchester.ac.uk/institutes/gdi/publications/workingpapers/futuredams/futuredams-working-paper-003-markkanen-braeckman.pdf
[12] https://www.energy.gov/sites/prod/files/2018/02/f49/Hydropower-Vision-021518.pdf
[13] https://www.hydro.org/wp-content/uploads/2016/07/Hydropower-Vision_Ch-2.pdf

- **Public Power Entities (PPEs)** are power generation utilities owned by the city, state or federal government.[14] PPEs employ even longer payback horizons and lower discount rates to value hydropower than IPPs and IOUs, and can fully finance projects using long-term revenue bonds.[13] Credit ratings for public power entities, including those that own and develop hydropower, are generally competitive due to the full-faith backing by their municipal government. For example, the hydropower-backed revenue bonds of the municipal consortium Missouri River Energy Services (the off-taker of the Red Rock NPD electrification project) were rated as high, investment grade (Aa3/AA- or above).

The financial structure and valuation timeframe for each owner/developer is driven not only by investment criteria (i.e. maximizing returns) but also by available sources of financing.[3] The strong investment grade ratings of public power entities participating in bond issuances can be marketed to a variety of fixed-income institutional investors such as banks or pension funds, whose investment criteria align with the long-term value streams of hydropower projects. Long-term PPAs (30+ years) arranged with entities with strong credit profiles such as PPEs provide assurance for repayment of project debt. IOUs can access medium- to long-term financing through stock market equity and corporate bond issuances, while project financing for IPPs typically involve high-cost investors (e.g. private equity sponsors and non-recourse loan providers) that are willing to accept higher risks for smaller capacity projects.

Amidst the different valuation and financing perspectives lies a core difficulty in hydropower project development – market values often do not align with development or operation timeframes.[13] The value of a hydropower asset during its licensing or permitting stages can differ immensely to the value at project-end due to the elongated timeline to reach commercial operations. Since 2005, the median hydropower project has taken more than twelve years from inception to commercial operation. In that timeframe, electricity and REC market prices have fluctuated with natural gas prices and varying state and federal policies, further adding uncertainty to its potential revenue streams and valuation prospects.

IOUs and public power investors, with their ability to internalize hydropower's benefits and finance project development using public debt or their internal balance sheets, can readily pursue hydropower projects.[13] IPP and non-utility developers, however, do not share these advantages and must undertake the lengthy and risky portions of the development process while depending on external equity funding. Conventional debt sources of project finance are typically inaccessible to these developers until lenders have adequate certainty that the projects addressed regulatory (e.g. FERC licenses) and revenue (e.g. PPAs) risks. Developers of small hydropower projects face additional challenges marketing to potential investors due to their limited scale and relative small dollar value. Large hydropower owners can capture a wide base of investors

[14] https://www.publicpower.org/system/files/documents/municipalization-what_is_public_power.pdf

through bond issues or loan prospects for which smaller projects do not have sufficient leverage to access these markets. When small projects are able to secure the interest of large, conventional financing sources such as commercial banks, their financing costs are usually much higher on a relative per MW basis.

IPPs and small-scale project developers often exit from hydropower ownership during the development stage, selling their equity stakes and licensing rights to IOUs, PPEs or other developers that are better equipped to complete the project. Changes in project ownership often take place between the license issuance and construction start dates.[15] Some NPD developers specialize in obtaining financing from private equity and strategic investors and navigating the licensing process. Once these developers reach those milestones, they transfer their development rights to another party that will continue with the permit requirements, construction and marketing agreements.

Two recent examples of license transfers for NPD projects are the Mahoning Creek Project and the Red Rock Hydroelectric Project.[15] Advanced Hydro Solutions obtained the FERC license for the Mahoning Creek project in March 2011 and sold it to Enduring Hydro in July 2012, who worked through the remaining USACE process requirements and ultimately constructed the project.[16] Similarly, Nelson Energy obtained the license to develop the Red Rock project in April 2011 but later transferred the rights to Western Minnesota Municipal Power Agency in January 2012 who ultimately constructed and commissioned the project.[17] Further detail on these projects and their license transfers are explained in their respective case study sections later in this paper. For more information on the organizational structure for hydropower project financing, the types of available funding and the different investors involved, please refer to the Appendix section of this paper.

D. Federal & State Financing Incentives

Similar to other renewables, hydropower has historically been eligible for the Renewable Energy Production Tax Credit (PTC) and the Business Energy Investment Tax Credit (ITC) to help finance its development.[15] Hydropower has been eligible for only half the value of the PTC relative to other renewables but does receive the full value of the ITC (30% of the project development cost).

The credits originally expired at the end of 2020, so that only projects that started construction before the end of 2020 could qualify.[18] Since the PTC is available for the first 10 years of production at a qualified facility, the credit can continue to be claimed well after the

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15 https://www.energy.gov/sites/prod/files/2015/04/f22/2014%20Hydropower%20Market%20Report_20150424.pdf
16 https://www.crainscleveland.com/article/20120828/FREE/120829812/advanced-hydro-solutions-sells-hydroelectric-project-in-western
17 http://www.unlockhydro.org/case-study
18 https://fas.org/sgp/crs/misc/R43453.pdf

PTC's stated expiration date. In December 2020, Congress passed extensions of both the PTC and ITC for one additional year, which will now expire in December 2021.[19] Despite the extensions, incentives based on tax credits can be ineffective for some hydropower projects. The use of tax credits to improve project economics requires tax equity investors who generally have a short-term investment window and require a higher cost of equity due the higher risk profile of their investment.[15] This locks out long-term, low-cost financing from institutional investors who lack sufficient tax burden and can offer traditional, less complex debt products.

Bond subsidy programs can further enhance financing for non-federal public entities developing hydropower.[15] These programs historically included Clean Renewable Energy Bonds ("CREB"), ARRA-funded Build America Bonds ("BAB"), Qualified Energy Conservation Bonds, among others. Eligibility and requirements vary per program yet all of these bond incentives enable public entities to finance hydropower and other qualifying projects at low rates, providing federal payment of tax credits to investors or cash payments to the issuing entity. Municipal bonds are commonly used to finance hydroelectric infrastructure bonds for projects in which a PPE acts as the project owner and a municipality acts as the project off-taker (e.g. the City of Hamilton for AMP's Meldahl hydroelectric project). Interest paid on municipal bonds is exempt from federal taxes, which allows PPEs and other entities to issue bonds at reasonable rates to meet their capital needs.[20]

Hydropower projects were eligible and received 24% of the 2009 CREB allocation of $2.2 billion, while CREBs and BABs have also been used to finance some of the largest NPD hydropower facilities.[15] The most prominent example is the financing used for AMP's Ohio River NPD projects – $1.7 billion of the total $2 billion expenditures used on the Cannelton, Smithland and Willow Island facilities was financed through the issuance of BABs and CREBs.[21]

E. Project Development Process: Long, Costly, Complex Timeline Drives Uncertainty

Hydropower has the longest and most complex development timeline of any of the available forms of renewable energy.[22] The timeframe for a new hydropower development project to reach commercial operation is between ten to thirteen years whereby most of the time is taken by licensing and permitting[5]. The regulatory process includes FERC licensing (five to six years), USACE permitting (two to four years), as well as other required regulatory approvals depending on the individual dam's location. Once the project obtains these regulatory approvals, it can proceed to construction, which can take two to three years excluding additional time potential delays such as flooding.

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[19] https://www.pillsburylaw.com/en/news-and-insights/tax-extenders-stimulus-bill-renewables.html
[20] https://www.hydro.org/policy/priorities/incentivizing-clean-electricity-deployment-manufacturing/
[21] https://www.amppartners.org/docs/default-source/investors/financial-reports/2017/2017_amp_consolidated_fs.pdf?sfvrsn=2
[22] https://www.hydro.org/wp-content/uploads/2020/05/NHA-federal-economic-recovery-package-TAX.pdf

Licensing and permitting require a considerable up-front financial commitment from the developer to undertake the engineering and environmental studies needed for federal and state agency approvals.[5] Redundancies and sequential reviews in this process are key reasons for project delays. For example, FERC may issue a license to a project but construction cannot commence until it has received the required approvals from the federal owner of the dam (USACE or Bureau of Reclamation). If there are unanticipated delays for these approvals, no work can begin. It is not uncommon for a hydropower applicant to spend over $10 million on the licensing process alone. The National Hydropower Association noted that for several owners of small hydropower projects, the high process costs for licensing and permitting can render projects uneconomical and result in the surrender of their licenses.

This disparity of timelines to reach commercial operations and potential process delays present a formidable challenge to new hydropower development especially when compared to alternative forms of energy.[5] Other renewable energies and fossil fuels can progress from inception to operation in less than half of the 10-year development timeline for hydropower. Private investors find the length and complexity of hydropower's timeline difficult to forecast and manage. As a result, hydropower development becomes expensive due to the compounding of interest costs over long periods coupled with their unclear risk profile. When facing these factors, many investors choose to invest in other forms of generation with far shorter timelines and clearer risk assessments.

F. Project Financing Risks & Risk Mitigants

Acquiring financing for hydropower projects is notoriously difficult, especially during the early planning and construction stages.[11] Large capacity hydropower projects will likely receive the support and participation of IOUs and PPEs whose creditworthiness, financial strength and overall scale can access public bond markets for funding. Smaller hydropower projects, like many NPD retrofit projects, cannot easily tap into these markets. First, small financing transactions attract less interest from banks (based on their preference for larger, commercial projects) and require more expensive debt to compensate for their lack of established credit histories and profiles.[23] Second, a small financing carries nearly the same legal, regulatory and marketing costs as a larger financing, rendering them less economical at a per transaction revenue or per transaction fee basis. Third, small hydropower assets are usually owned by small-scale developers that can only assume a certain amount of debt compared to larger project developers who can leverage their robust balance sheets to take on higher levels of debt.

The availability of financing depends on the perceived risks and expectations of future revenue streams by potential investors.[11] To secure investor capital, project developers must

[23] https://efiling.energy.ca.gov/GetDocument.aspx?tn=234752&DocumentContentId=67611

identify possible revenue sources to be used to service their debt and provide a return on investment to its equity investors. The risks are particularly high during the pre-development phases (planning and design) as the failure of the project at this stage could lead to the loss of all available financing. Following the construction phase, many of the greatest risks associated with the project will have been eliminated or managed, making the project more attractive to investors.

To improve a project's attractiveness to financiers, the government may introduce subsidies, provide equity or low-cost debt or separate out the project's financially viable aspects from the non-viable aspects (e.g. considering the dam and power station as two separate projects).[11] To increase its bankability to private sector investors, a project needs to produce a predictable income stream. Questions around the affordability and price of electricity as well as the credit-worthiness of the off-taker are crucial to these investors. Unfortunately, the private sector's interest in NPD electrification and its financial opportunities have not been associated with extensive literature on the process. As more hydropower projects are developed wholly or partially with private finance, a better understanding of the factors that attract financing, as well as the risks that hinder private sector involvement, will evolve.

Not all private investors take the same view of a project, as some will contemplate higher risks than others. Regardless, all investors undergo through the same process of evaluating financial viability and risks. During the on-set of the project financing evaluation process, the project developers and investors convene to decide on the following:[11]

- finding a balance or choosing between public and private parties for financing;
- a mix of equity and debt financing;
- identifying possible financial risks across various stages of project development and implementation

The degree to which financial risks can be mitigated will influence the choice of project structure. If the risk is substantial and cannot be mitigated to any significant degree, investors will exit and the project could face possible dissolution.

G. NPD Hydropower Development Case Studies

The following case studies represent U.S. NPD hydropower development projects over the past ten years that have been commissioned or are currently in development or construction. The case studies focus on analyzing the types of funding used to finance these projects, stakeholders, PPAs, off-takers, financing challenges, and key takeaways for future NPD projects to secure project financing.

1. Red Rock Hydroelectric Project

The Red Rock Hydroelectric Plant is a recent example of an NPD retrofit that garnered significant institutional and retail investor interest in the public debt markets. This 36MW hydroelectric project of an existing USACE-owned NPD is located on the Des Moines River, a major tributary of the Mississippi River, just southwest of Pella, Iowa.[24] The plant completed construction in September 2020 and is waiting for final wet commissioning in March 2021. The project was co-developed between Missouri River Energy Services ("MRES") and Western Minnesota Municipal Power Agency ("WMMPA"). MRES operates as a municipal power provider of wholesale electric services to 61 communities across Iowa, Minnesota, North Dakota, and South Dakota.[25] MRES owns the FERC license for the Red Rock project and will operate the facility following commission. WMMPA operates as a joint-action agency made up of MRES members in the state of Minnesota.[26] WMMPA has historically provided financing for all of the power supply and transmission facilities used to serve these 61 MRES members. As such, WMMPA arranged the project financing and is the project owner of the Red Rock facility.

MRES developed the Red Rock facility to diversify its members' renewable resource portfolio with clean and reliable baseload energy.[27] This investment represents the first hydropower development in the Des Moines River Basin in decades. MRES aims to add non-intermittent electrical capacity and comply with the renewable energy mandates and goals of the State of Minnesota through this project.[28]

The WMMPA and MRES partnership is bound under a power supply contract in which WMMPA is obligated to sell to MRES and MRES is obligated to buy from WMMPA 100% of the electricity generated from all WMMPA-owned supply and transmission facilities including Red Rock.[29] This power supply contract is secured on a take-and-pay basis – MRES members must take and pay for all electric power and energy made available under this agreement regardless of whether the consumers use the power.

Nelson Energy was the original FERC licensee for the Red Rock facility.[30] Nelson Energy operates as a privately held Minneapolis-based company specializing in the development of hydroelectric potential at existing dams.[31] Nelson Energy obtained the license in April 2011 but transferred the development rights to MRES in January 2012 for $360 million.[31,15] Nelson Energy holds an equity interest in Red Rock and is an advisor on the project. More than 40 plans, permits and licenses had to be secured throughout the development stages of the project.[48]

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24 https://www.hydro.org/powerhouse/red-rock-hydroelectric-project-a-model-for-the-future-of-clean-energy/
25 https://www.redrockhydroproject.com/
26 https://www.mrenergy.com/about/wmmpa
27 https://www.publicpower.org/periodical/article/western-minnesota-municipal-power-agency-high-financial-rating-affirmed
28 https://www.transmissionhub.com/wp-content/uploads/2018/12/Missouri-Basin-JUN-30-2016-IRP.pdf
29 http://www.oasis.oati.com/MRET/MRETdocs/MRES_annual_report_2014.pdf
30 http://www.rrva.org/022216/L&D%20Hydropower%20Nelson%20Energy.pdf
31 http://www.nelsonenergy.us/ourprojects.html

WMMPA secured financing for the Red Rock project in June 2014 via a $351 million public debt raise comprised of tax-exempt power supply revenue bonds.[25] Most of the bonds were sold at a premium due to strong demand and market conditions. The demand was owed to strong credit ratings for WMMPA (AA- by Fitch Ratings and Aa3 by Moody's) and bond interest rates that were significantly lower than comparable recent transactions for highly rated utility entities. The bonds were issued at an attractively low interest cost of 4.05% with an average bond maturity of 21 years and final maturity slated for 2046. WMMPA does not frequently issue debt, building scarcity and raising demand for its investment grade bonds. Investors immediately seized the opportunity to purchase bonds when WMMPA arrived to market to finance the Red Rock facility. The bonds were secured by a pledge of all revenue WMMPA receives from its power supply resources including Red Rock, providing a safe means of collateral to its investors that was further bolstered by its long-term power supply contract with MRES.

Moody's reported that the strong credit rating for WMMPA was supported by the company's sound financial policies, ample liquidity and strong debt service coverage for its bond holders.[32] The ratings were also reinforced by the low cost of power for WMMPA member participants as well as the overall credit quality and diversity of MRES, who shares a similar strong financial profile to WMMPA and whose 61 member communities across various a multi-state can mitigate customer and geography risk. Fitch Ratings supported Moody's in terms of WMMPA's creditworthiness but highlighted that the agency's outstanding debt will more than double and members rates will need to increase in the near-term to service the additional leverage.[33]

Final proceeds received from the bond issue were approximately $390 million, representing an upsize of $40 million, due to considerable investor interest in the Red Rock bonds.[25] WMMPA also took advantage of the strong bond demand to re-price the bonds, resulting in significant interest savings to its members. Major financial institutions such as Citigroup, JP Morgan, Barclays, Wells Fargo and US Bancorp were involved in the public debt raise. MRES estimated the project's total capital needs to be $420 million; the debt financing accounted for ~90% of this total.

In June 2018, exactly four years after the initial debt raise, WMMPA raised another $82 million in tax-exempt power supply revenue bonds to complete construction on the Red Rock project, pay for miscellaneous transmission improvements and additional capital expenditures, and cover the cost of issuance. The all-in true interest cost of the debt offering was 3.9% with an average maturity of fewer than 22 years; the interest rate reflected the lowest borrowing cost in

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[32] https://www.moodys.com/research/Moodys-affirms-Aa3-rating-on-Western-Minnesota-Municipal-Power-Agency--PR_906503612

[33] https://www.businesswire.com/news/home/20140619006425/en/Fitch-Rates-Western-Minnesota-Muni-Power-Agencys-2014-Series-A-Bonds-AA--Outlook-Stable

WMMPA's history. Both Fitch Ratings and Moody's affirmed their long-standing investment grade ratings for WMMPA, assigning bond ratings of AA- and Aa3 respectively. Citigroup again led the public debt issue as senior underwriter and strong bond demand allowed the underwriting syndicate to reduce interest rates from the initial offering price. The debt service savings enabled MRES to maintain its members' power supply costs among the lowest in the region.

In October 2019, WMMPA raised $322 million in taxable power supply refunding bonds to refinance existing tax-exempt bonds from the 2014 bond raise.[25] The refinancing was secured at a record 3.13% interest cost, again the lowest in WMMPA's history, and provided over $50 million in savings to MRES members over the term life of the bonds. The debt instruments were issued on a taxable basis since Congress withdrew the ability to advance refund bonds on a tax-exempt basis following the Tax Cuts and Jobs Act of 2017. If tax-exempt advance refunding were possible, the savings would have been significantly greater than $50 million.

Before closing the refinancing transaction, WMMPA received a strong Aa3 rating from Moody's and an equally robust AA- rating from Fitch Ratings.[34,35]At the time, WMMPA was among the few U.S. utility providers to earn double-A ratings from both rating agencies.[2] Moody's updated analysis and rating highlighted delays in the construction of the Red Rock project, caused mainly by high water. However, Moody's also pointed positively to the continued low-cost power supply, sound financial policies, debt services coverage, credit quality of member systems, and diversified generation mix of MRES. MRES CFO Merlin Sawyer commented that his company's strong financial position and policies, along with the strong reputation of all Red Rock project participants, played a significant factor in maintaining high credit ratings. There is a strong likelihood that WMMPA can obtain favorable interest rates for future bond sales of its projects including Red Rock.[27]

With commercial operations expected to begin in early 2021, the Red Rock facility is projected to take over seven years since its initial public bond raise to reach revenue generation.[36] USACE will continue to exert certain administrative controls over the Red Rock plant such as dictating the water supply.

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34 https://www.moodys.com/research/Moodys-assigns-Aa3-rating-to-Western-Minnesota-Municipal-Power-Agency--PR_906084226
35 https://www.fitchratings.com/research/us-public-finance/fitch-rates-western-minnesota-muni-power-agency-2019-bonds-aa-outlook-stable-10-10-2019
36 https://www.amesconstruction.com/projects/red-rock-hydroelectric

2. AMP's Ohio River Hydroelectric Dams

This case study examines how American Municipal Power ("AMP")'s Ohio River dams provided the precedent for Red Rock and future NPD projects to access public debt markets for project financing. AMP operates as a nonprofit wholesale power supplier for 135 city-owned member utilities across nine states in the Midwest and Mid-Atlantic.[37] Over the past decade, AMP developed four hydroelectric power plants on existing USACE-owned NPDs with a total 313MW electrical capacity. Located in the Ohio River in West Virginia and Kentucky, these facilities have a total project development cost of approximately $3.5 billion.[38] The AMP dams are only a handful of facilities along the Ohio River region that have the potential to generate about 3,000MW of additional hydroelectric generating capacity in this area alone.[39]

AMP pursued the projects to add member-owned generating capacity that would both reduce member exposure to the unpredictable costs of purchasing open market electricity and diversify its resource portfolio.[40] The four run-of-river projects were built simultaneously, including the Meldahl Locks and Dam project that was developed jointly with the City of Hamilton, OH, to achieve economies of scale and cost synergies. Each individual project share substantially similar design elements built on the electrification of existing dams.[41] See below an overview of the four AMP Ohio River hydroelectric facilities:[37]

- **Cannelton** (88MW), Hawesville, KY, commercial operations in June 2016
- **Smithland** (76 MW), Smithland, KY, commercial operations in August 2017
- **Willow Island** (44MW), St. Marys, WV, commercial operations in February 2016
- **Meldahl** (105MW), Maysville, KY, commercial operations in April 2016, developed in partnership with AMP member City of Hamilton, OH

a) Combined Hydroelectric Project Dams

AMP's Combined Hydroelectric Project ("CHP", which includes Cannelton, Smithland and Willow Island projects) was financed in a single municipal bond raise of $2.2 billion in September 2009.[41] The bond raise consisted of a multi-pronged financing structure utilizing several tax-advantaged financial instruments.[42] The structure included both federally taxable and tax-exempt bonds including Green Bonds Build America Bonds, Clean Renewable Energy Bonds and New Clean Renewable Energy Bonds. The bonds were distributed to both institutional and retail investors, including 30 investors who never owned AMP bonds

[37] https://www.amppartners.org/generation/hydro
[38] https://www.dispatch.com/news/20170906/american-municipal-power-finishes-hydroelectric-power-plant-projects
[39] https://www.eia.gov/todayinenergy/detail.php?id=27092
[40] https://www.wvnews.com/wvs-newest-power-plant-dedicated/article_402e7c12-2cc1-54e6-b9d1-c0b36a111589.html
[41] https://www.fitchratings.com/research/us-public-finance/fitch-rates-american-municipal-power-inc-oh-combined-hydro-project-a-outlook-stable-02-09-2016
[42] https://www.hydro.org/wp-content/uploads/2020/09/NHA-comments-on-S.B.-100-Results-Workshop.pdf

previously. The strong investor demand resulted in a 1.5x bond oversubscription, which allowed AMP to tighten credit spreads on the issued bonds to earn additional interest savings.

CHP signed PPAs with 79 of its member utility firms including Cleveland Public Power and Paducah Power System, of which the two combine for 20.5% of total project allocation.[41] CHP ownership interests among member utility firms range from Cleveland's 16.8% to 56 participants with individual shares of less than 1%. Thus, no single participant has a dominant obligation in the power purchase contracts. The ownership interests are appropriately sized based on individual peak demand to offset high power unit costs. Investors highlighted that although the projects provide power that was well above current prices (in excess of $130/MWh), the production cost per KWh compared to regional energy prices was still very competitive. Furthermore, the newly generated low-carbon power provided an alternative to existing fossil fuel generation (especially in Kentucky and West Virginia with notably high natural gas production) and offers fuel diversity to AMP members. AMP CEO Marc Gerken also noted that the operating costs of the hydroelectric facilities were low after taking into consideration the high upfront capital costs and debt service, which are expected to be paid off after 30 to 35 years.[40]

The CHP PPAs are supported by strong take-or-pay contracts that obligate the 79 participating municipally owned electric systems to purchase all of the CHP power generation, securing the debt service on the bonds.[41] The contracts also include standard step-up provisions that require each participant to purchase up to 125% of its original allocation of the project output in the event that another participant defaults. This step-up provision is sufficient to cover a default of the largest member entitlement of 16.8% held by Cleveland Public Power.

Fitch Ratings assigned A-level ratings to CHP's individual project revenue bonds due to the creditworthiness of the underlying participants, who have exhibited satisfactory cash flows, modest leverage levels and healthy cash balances.[43] These participants must demonstrate financial worthiness prior to becoming an AMP member and undergo annual credit reviews to continue participating in AMP.[23] In addition, given that there are 79 participating utility firms consisting of a wide variety of member cities and towns dispersed over a broad geographic area, the diversity helped mitigate geographic and customer risks.[41] Six of the largest members with offtake agreements, representing 47% of CHP participation, have financial and debt metrics that displayed satisfactory credit characteristics for Fitch Ratings.

CHP's strong marketability to bond buyers was also owed to AMP's overall creditworthiness. AMP had substantial liquidity through a revolving $750 million line of credit expandable to $1 billion with a syndicate of banks.[42] AMP also has significant and relevant hydroelectric generation experience, having operated similar hydroelectric facilities along the Ohio River and its tributaries for decades.

[43] https://www.fitchratings.com/research/us-public-finance/fitch-rates-american-municipal-power-inc-oh-combined-hydro-project-a-outlook-stable-02-07-2018

b) Meldahl Hydroelectric Dam

The Meldahl hydroelectric project was financed separately from CHP due to its undivided ownership between AMP at 48.6% and the City of Hamilton, Ohio at 51.3%.[44] In addition to Hamilton, OH, 47 other AMP member cities are purchasing the energy offtake from the Meldahl facility. The financing took place in December 2010 in which $685 million of taxable, tax-exempt and tax-advantaged bonds (Build America Bonds, Clean Renewable Energy Bonds and New Clean Renewable Energy Bonds) were issued. The final maturity of the bonds is slated for 2050 and the bonds bear interest rates at fixed rates between 4.4% and 7.5%.

The bonds were secured by 50-year take-or-pay PPAs with 48 AMP participating members providing a long-term revenue pledge to the newly issued debt service.[44] The PPAs include a 106% step-up provision in the event that Hamilton, the largest individual project member, becomes a defaulting party. AMP is also required to maintain a debt service coverage ratio (net Meldahl revenues to net Meldahl debt) of 1.1 or greater as part of the terms of the bond issue. AMP also expected to receive a cash subsidy payment from the U.S. Treasury over the term life of the Build America Bonds equal to 35% of the interest payable on each interest payment date for these bonds.

Moody's assigned an A3 credit rating to all Series 2010 bonds issued in the December 2010 financing.[44] The strong credit quality was owed to the unconditional take-or-pay obligation of the 48 municipal project participants to cover the debt service on the bonds. The debt instruments were used to not only finance the construction but also the operating and maintenance costs of the Meldahl facility. The A3 rating placed significant weight on the 51% obligation share of Hamilton, Ohio (the city also earned an Aa3 rating from Moody's). The Meldahl facility offers competitive member retail rates as the rates for the City of Hamilton are 30% below the rates of the neighboring major IOU. The rating also considered the long-term expected value and economics of the hydroelectric project, as well as the A1 issuer credit rating assigned to AMP, due to its effective role as a power supplier to a diverse group of utilities across a multi-state region.

The main financial risks that the credit rating agencies assessed towards the Meldahl project consisted of (i) high capital costs, (ii) construction risk that could increase capitalized interest costs, (iii) increased debt ratios for AMP participant members, and (iv) continued USACE regulation of water levels which can prolong administrative action.

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[44] https://www.moodys.com/research/MOODYS-ASSIGNS-A3-TO-AMERICAN-MUNICIPAL-POWER-S-MELDAHL-HYDRO-New-Issue--NIR_16778097

c) Sequestration on Subsidized AMP Bonds

In March 2013, the federal government mandated sequestration (spending cuts) on direct credit subsidy payments of BABs and New CREBs, both of which were used to finance the public bond raise for AMP's CHP and Meldahl hydroelectric projects.[45] Through this mandated sequestration, federal subsidy payment to issuers of BABs and New CREBs was reduced through 2029, meaning that AMP must cover the interest difference on these bonds (since the federal government can no longer commit to the subsidy).[46] AMP faced an estimated reduction of more than $76 million in federal subsidies through 2029 on these bonds. This sequestration on BAB and New CREB payments provide an example of the shortfalls of alternative financing using "tax-advantaged" financial instruments (e.g. the likelihood of subsidy payments to cease in the near term and cause unanticipated financial burden to project developers).

AMP requested Congress to restore full BABs and New CREBs payments by either shielding credit payments from sequestration or restoring the cut payments through an annual gross-up payment.[46] AMP also requested Congress to take action to reclassify BABs and New CREBs so that these instruments will not be subject to future sequestration. These efforts can assuage concerns for future NPD developers regarding the use of public debt markets and tax-advantaged or -subsidized financial instruments to fund their electrification projects.

3. Fiera's Dorena Lake & Clark Canyon Hydroelectric Dams

Canadian-based investment firm Fiera Infrastructure currently owns two U.S. hydroelectric facilities that serve as examples of small-scale NPD retrofit projects attracting privately issued structured debt for project financing. The 7.5MW Dorena Lake Dam in Oregon and 4.7MW Clark Canyon Dam in Montana have undergone multiple project owners throughout their history but nevertheless received the necessary private debt financing to fund their development. In May 2012, Riverbank Power, a Canadian developer of alternative energy, closed $38 million in project financing to develop the two run-of-river hydroelectric retrofitting projects.[47] The projects involved adding hydropower equipment to the USACE-owned structures used primarily for flood control, irrigation and navigation.

The $38 million financing included $26 million in non-recourse debt and $12 million in sub-debt financing to fund construction and involved multiple Canadian-based parties in its issue and arrangement.[47] Travelers Capital, a Canadian alternative capital provider to public and private middle market enterprises, arranged the $26 million senior secured credit facility. Industrial Alliance, a leading Canadian insurance and wealth management provider financed the

45 https://www.amppartners.org/docs/default-source/investors/financial-reports/2017/2017_amp_consolidated_fs.pdf?sfvrsn=2
46 https://www.amppartners.org/docs/default-source/regulatory-legislative-comments/legislative/2020/amp_comments-clean_future_act.pdf
47 https://www.newswire.ca/news-releases/riverbank-power-closes-38-million-project-financing-for-75-mw-dorena-lake-and-47-mw-clark-canyon-run-of-river-hydroelectric-retrofit-projects-510227881.html

debt facility, consisting of a construction loan followed by 20-year term loans for each of the two projects. Canadian-based Aquila Infrastructure Management financed the remaining $12 million of sub-debt financing.[48] Aquila also formed a strategic partnership with Riverbank to manage construction and logistics of the two projects.[49]

The 40-year FERC license for the Dorena Lake project was initially granted in late 2008 and the FERC license for Clark Canyon was granted later in August 2009.[50] Riverbank subsequently secured a 20-year PPA with PacifiCorp, a private utility firm serving the Western U.S., for Dorena Lake and a 20-year PPA with Idaho Power, a regulated power utility firm, for Clark Canyon.[51,52] Both PPAs entitled the utility firms to the purchase of 100% of the facilities' electrical output. In a three-year time frame, Riverbank obtained the necessary USACE approvals, FERC licensing, adequate financing, and long-term PPAs for the two NPD hydropower development projects to proceed towards construction.

The construction phase, however, was met with significant challenges as Riverbank disbanded and Aquila consequently acquired the FERC licenses for both Dorena Lake and Clark Canyon.[49] New limited liability corporations were formed ("Dorena Hydro LLC" and ("Clark Canyon Hydro LLC") to acquire the development rights from Riverbank, who was unable to complete construction.[53] The projects were initially delayed due to Riverbank's mismanagement and neglect to file necessary updates and project plans to FERC in a timely manner.[51] The Dorena Lake project faced further delays due to financial and construction disputes between the project owner and the general contractor.[54] The contractor raised concerns surrounding incomplete construction plans, failure to obtain crucial federal permits on time, defective equipment, among others. The delays disqualified Dorena Hydro LLC from an expected $8 million government subsidy and ballooned development costs up 80% to $20 million for the Dorena Lake facility alone. The Dorena Lake project had an estimated final development cost of $25 million, or 65% of the May 2012 private debt financing.

Following two years of construction and running a full year behind schedule, the Dorena Lake facility was eventually commissioned in August 2014.[55] This marked the first non-federal hydropower development within the Portland District in over 20 years. In March 2016, Aquila formed Fiera Infrastructure, a joint venture with Montreal-based Fiera Capital, who later acquired the Dorena Lake and Clark Canyon projects and paid off the debt from the May 2012

48 https://www.monitordaily.com/news-posts/travelers-capital-arranges-26-million-riverbank-power/
49 https://www.registerguard.com/article/20140123/NEWS/301239841
50 https://www.hydroreview.com/world-regions/new-development-building-7-5-mw-dorena-lake-at-an-existing-dam/#gref
51 https://www.fierainfrastructure.com/en/the-assets/renewable-energy/hydroelectric/dorena-hydroelectric-facility/
52 https://www.fierainfrastructure.com/en/the-assets/renewable-energy/hydroelectric/clark-canyon-hydroelectric-facility/
53 https://docs.house.gov/meetings/IF/IF03/20160202/104387/HHRG-114-IF03-20160202-SD005.pdf
54 https://www.oregonlive.com/pacific-northwest-news/2014/04/oregon_hydroelectric_project_a.html
55 https://www.fisheries.noaa.gov/west-coast/habitat-conservation/west-coast-federal-energy-regulatory-commission-ferc-licensed-12

financing.[56] Fiera Infrastructure currently holds a 100% equity ownership in both projects. The Clark Canyon project required multiple extensions to its existing FERC license and is currently in late-stage development (marking eleven years of development since the initial issue of its FERC license).[54]

4. Blue Heron Hydroelectric Dams – Ball Mountain & Townshend

The Blue Heron hydroelectric dams share similarities with the previously discussed Fiera Infrastructure NPD electrification projects – both involved small-scale NPD retrofits that attracted private debt capital. The key difference with the Blue Heron projects, however, is their use of mezzanine loans and strong state government support to facilitate PPAs and market-competitive pricing. In July 2012, Eagle Creek Renewable Energy, a leading developer and operator of U.S. hydroelectric power plants, acquired Blue Heron Hydro and its 3MW NPD electrification projects.[57] At the time of the acquisition, Eagle Creek was sponsor-backed by Hudson Clean Energy Partners, a private equity firm and investment fund focused on clean energy investments with over $2 billion of assets under management. Eagle Creek had then owned 31 small-scale hydroelectric facilities across six states for a combined capacity of 64MW. Blue Heron Hydro owned the development and licensing rights of two USACE-owned dam sites, Ball Mountain and Townshend, located on the West River in Southern Vermont. The acquisition marked the first pure development project for Eagle Creek and fulfilled its strategy to pursue construction of clean energy generation facilities from late stage development projects.

FERC issued 50-year operating licenses to the two Blue Heron projects earlier in 2012.[57] During that time, Blue Heron Hydro secured long-term PPAs through the Vermont Sustainably Priced Energy Development (SPEED) program with the intended support of helping Vermont reach 20% renewable energy generation by 2017. SPEED represents the nation's first feed-in tariff ("FIT"), a policy mechanism designed to support the development of renewable energy sources by providing a guaranteed, above-market price for producers[101]. FITs usually involve long-term contracts of over 15 years and are designed to increase the economic feasibility and market competitiveness of small-scale early development clean energy projects such as NPD electrification. Through SPEED, renewable energy developers can receive a long-term fixed contract for renewables facilities located in the State of Vermont of up to 2.2MW in size. Because of the capacity limit, Ball Mountain was built at a 2.2MW capacity and Townshend at 0.9MW.[58] SPEED is also responsible for facilitating contracts between the state's electric distribution utilities and the owners of qualifying SPEED projects to purchase the generated

56 https://www.newswire.ca/news-releases/fiera-capital-joins-forces-with-aquila-infrastructure-management-and-creates-new-infrastructure-platform-573057131.html
57 https://www.businesswire.com/news/home/20120806005830/en/Eagle-Creek-Renewable-Energy-Acquires-Blue-Heron-Hydro-LLC-Will-Develop-Two-New-Hydroelectric-Facilities-on-Vermont%E2%80%99s-West-River
58 https://www.georesources.net/index.php/global-news/obermeyer-commissions-turbines-for-ball-mountain-and-townshend-hydroelectric-projects-in-vermont

output. This feature of SPEED helped alleviate Blue Heron Hydro from the common PPA shortfalls that inhibit small NPD projects from coming online.

The PPAs structured under the SPEED program required the projects to be commissioned at the end of 2013. However, the projects suffered through multiple extensions, culminating on a final commission date in July 2016 that marked over two years behind schedule. Eagle Creek cited the following reasons behind the delays: (i) weather and flooding, (ii) complex technical work during construction, and most importantly (iii) lengthy delays in receiving USACE permits due to a severe backlog at the agency.[59] The Blue Heron projects fell under the North Atlantic jurisdiction of USACE, which had a major role in responding to the natural disasters and flooding events caused by Tropical Storm Irene and Hurricane Sandy. USACE had also been operating under reduced resources and manpower as a result of the federal budget sequestration of 2013 and ensuing budget cuts.

Despite the backlog, Army Corps officials acknowledged the excellent planning and coordination imparted by Eagle Creek throughout the regulatory process. Eagle Creek CEO Bud Cherry highlighted that the Blue Heron projects would serve as a stepping-stone for the company to pursue future NPD hydropower development opportunities, particularly at larger-sized facilities given the company's significant growth since acquiring Blue Heron Hydro back in 2012. Eagle Creek EVP David Youlen further noted that Blue Heron Hydro had spent more than $14 million on design, equipment procurement, permitting, and construction on this development.[60] The final total development costs for these projects remain undisclosed.

Eagle Creek financed the development of the Blue Heron hydroelectric dams, as well as the rest of its 40+ hydropower portfolio using mezzanine financing, a combination of debt and equity financing. Some private equity firms such as Hudson Clean Energy receive a portion of their investment funds from mezzanine lenders that borrow money to sponsors in the form of subordinated debt. During the development stages for the Blue Heron projects, Eagle Creek and Hudson Clean Energy received mezzanine financing from Ullico Infrastructure Fund, the infrastructure-financing arm of insurance and investment company Ullico. In late 2015, Ullico Infrastructure issued a $20 million mezzanine loan to finance Eagle Creek's hydropower pursuits.[61] Eagle Creek indicated that it intends to use these proceeds to acquire and develop additional hydroelectric assets throughout the country. The investment also allowed Ullico to broaden its footprint across new states and gain a foothold in the hydroelectric generation sector, especially given its interest in zero-fuel cost base load power production. Eagle Creek also strategically aligned with Ullico's investment philosophy in financing low risk infrastructure and utility assets. Later in October 2016, Ullico closed another $50 million round of mezzanine

[59] https://vtdigger.org/2016/06/09/new-west-river-hydro-projects-declared-operational/
[60] https://vtdigger.org/2015/12/17/extension-granted-two-southern-vermont-hydro-projects/
[61] https://www.ullico.com/newsroom/bulletin-2016-1-3

financing for Eagle Creek to fund its continued expansion in U.S. hydropower, noting that the proceeds will help cover the Blue Heron projects that had been recently commissioned.[62]

Eagle Creek eventually shifted from attracting private to public interest in the form of Ontario Power Generation ("OPG"), the state-owned public utility provider of the Government of Ontario. In November 2018, OPG acquired Eagle Creek and its entire hydropower portfolio for $298 million from Hudson Creek Energy Partners among other investors.[63]

5. Mahoning Creek Hydroelectric Dam

This case study on the Eagle Creek-operated Mahoning Creek Hydroelectric Dam analyzes how the use of grant-funding and successful public-private partnerships can improve the economic feasibility for NPDs and facilitate their timely completion. The Mahoning Creek project is the 6MW electrification of a USACE-owned NPD located in Armstrong County, Pennsylvania (60 miles from Pittsburgh) on a tributary of the Allegheny River.[64] When commissioned in late 2013, the dam became the first hydroelectric project built at a USACE-owned site in Pennsylvania in more than 20 years. The project was enabled by the 2009 American Recovery and Reinvestment Act and Pennsylvania Alternative and Clean Energy Program and involved a strong public-private partnership with the USACE's Pittsburgh District. The original developer was Advanced Hydro Solutions who, in July 2012, sold the project to Enduring Hydro, a private investment and development firm specializing in hydropower. Through the acquisition, Enduring Hydro acquired the 50-year FERC license and later began construction on the project in February 2013. The construction created more than 100 jobs utilizing local labor in Armstrong County.

The original March 2010 FERC license application disclosed several investment details of the Mahoning Creek project including an 8% internal rate of return, an 8% cost of capital and a total financing term of 20 years.[65] The application specified that the project had a net investment value of $11.1 million, including $10.5 million in total capital costs and $0.7 million in licensing costs. The document did not disclose the exact source or use of funding for this project (e.g. debt vs. equity).

In May 2013, Enduring Hydro secured a 10-year PPA with Pennsylvania State University to purchase all of the net electric output generated by the facility.[66] The PPA was finalized while the plant was still in construction, at a time when electricity prices decreased significantly which

62 https://www.hydroreview.com/business-finance/ullico-provides-50-million-in-financing-to-eagle-creek-renewable-energy-for-hydropower/
63 https://www.hydroreview.com/business-finance/ontario-power-generation-has-finalized-its-acquisition-of-eagle-creek-renewable-energy/#gref
64 https://www.renewableenergyworld.com/baseload/adding-power-to-a-non-powered-dam-mahoning-creek/#gref
65 https://lowimpacthydro.org/wp-content/uploads/2020/08/C-FERC-Environmental-Assessment.pdf
66 https://news.psu.edu/story/336782/2014/12/03/campus-life/hydroelectric-facility-supplies-8-percent-penn-states-energy

magnified the project's financial risk.[67] This decline in electricity prices made it difficult for Enduring Hydro to find a long-term buyer for the output. Penn State pursued the PPA with the Mahoning Creek facility to fulfill its sustainability goals, which include a 35% target reduction in greenhouse gas emissions by 2020. The Mahoning Creek facility currently supplies the university with 8% of its total electricity generation.

The project was commissioned in December 2013 after only ten months of development, at an estimated cost of $16 million.[6] The Enduring Hydro team credited its public-private partnership with the USACE, FERC, Pennsylvania Department of Environmental Protection among other agencies for the successful and timely completion of the project.[63]

Enduring Hydro strategically managed the permitting, approval and construction processes simultaneously rather than sequentially to realize time efficiencies in light of the project's tight construction schedule. The developer planned and tiered the construction activities in stages, with each one corresponding to the receipt of various approvals over a four-month period of time. Enduring Hydro worked closely with a team of consultants to anticipate and address the concerns of its key regulatory partners, plan detailed timelines to obtain regulatory approval, coordinate all involved parties and keep them informed of all process updates, and efficiently manage the tiered construction schedule.

The Mahoning Creek project benefited from renewable energy financial incentives that significantly improved its economic viability and supported its commercialization. Since the project reached operations prior to January 2014, it qualified for the U.S. Treasury's Section 1603 cash-back grant designed to increase investment in domestic clean energy production. Enduring Hydro received a total of $10.2 million in public grants for the project, including $4.9 million from the Section 1603 grant and $5.3 million from a USDA loan guarantee from the Office of Rural Development, both granted in the summer of 2014.[68]

In January 2014, shortly after commissioning Mahoning Creek, Enduring Hydro formed Cube Hydro Partners with I Squared Capital, a global infrastructure private equity fund, to further enable acquisitions and growth in hydropower.[69] At the time of the acquisition, the newly formed Cube Hydro operated 13 hydropower facilities. Cube Hydro was later acquired by Eagle Creek Renewables, which currently owns and operates over 85 hydroelectric facilities in the U.S., including the previously discussed Blue Heron facilities.

Despite the successful commercialization of the Mahoning Creek project, Cube Hydro stressed that the regulatory process was still overly long and caused financial uncertainties. The overall approval process spanned nearly a decade starting from when the preliminary permit application was submitted in October 2004 to when the final federal, state and local permits were

[67] https://docs.house.gov/meetings/IF/IF03/20150513/103443/HHRG-114-IF03-Bio-CollinsJ-20150513.pdf
[68] https://www.treasury.gov/initiatives/recovery/Documents/Section%201603%20Awards.xlsx
[69] https://www.enduringhydro.com/

received in March 2013.[9] Even though the FERC license was formally issued in March 2011, that license did not settle many of the regulatory risks associated with the Mahoning Creek development and required additional approvals from USACE and multiple agencies from the State of Pennsylvania. These final approvals and resulting permits required additional environmental requirements, and took another two years to receive. The protracted timeline and uncertainty in receiving final approvals, along with the aforementioned decline in electricity prices, made it difficult for Enduring Hydro to find a long-term buyer to sign a PPA for Mahoning Creek. Cube Hydro recommended federal and state resource agencies to cooperate in their environmental and regulatory reviews, remove redundancies, and implement schedule discipline to reduce uncertainties and manage risks. These actions can help resolve the shortfalls of a long-term PPA, regulatory conflicts and other development risks that are inhibiting NPD hydropower development in the U.S.

6. Lower St. Anthony Falls Hydroelectric Dam

The Lower St. Anthony Falls case study presents an NPD hydropower development that benefitted from both the project financing and management of a major publicly traded infrastructure investment firm (in spite of its small electrical generating capacity) as well as strong local and state support. This 9MW run-of-river hydroelectric plant was built on an existing USACE-owned dam in downtown Minneapolis on the Mississippi River.[70] This project was a co-development between Nelson Energy (original developer of the Red Rock facility), SAF Hydroelectric (the original FERC licensee) and Brookfield Power.

In March 2007, Brookfield Power purchased a partial ownership interest in SAF Hydroelectric, acquiring the 50-year FERC license for Lower St. Anthony Falls as well as its development rights.[71] Brookfield Power (now Brookfield Renewable Energy Partners) operates as the renewable power arm of Brookfield Asset Management, one of world's leading infrastructure funds with $70 billion of assets under management (at the time of the SAF acquisition). The developers noted that the timeline from initial license outreach to project license award took 5 years.[70] Brookfield provided project financing and bore responsibility over construction and eventual operation of the $40 million project.[72]

Through Xcel Energy, a major U.S. utility provider, the project secured a $2 million Renewable Development Fund ("RDF") grant to cover its development costs.[73] Financed by Xcel Energy's Minnesota electric customers, the RDF award is designed to promote renewable energy projects in the local Minnesota service area. In addition to the RDF grant, the project qualified for Renewable Energy Production Incentive ("REPI") payments and federal stimulus

[70] https://www.xcelenergy.com/staticfiles/xe/Corporate/Corporate%20PDFs/LSA_Final_Report_Milestone11.pdf
[71] https://www.hydroreview.com/business-finance/brookfield-buys-stake-in-898-mw-lower-st-anthony/#gref
[72] https://www.leg.mn.gov/docs/2020/mandated/200288.pdf
[73] https://www.fmlink.com/articles/xcel-energy-grants-over-22-million-for-25-renewable-energy-projects/

grants through renewable energy tax credits (although it is unspecified whether the project qualified for the ITC or PTC).[70,74] Xcel Energy also secured a 15-year PPA with the original project developer to purchase the facility's electrical output, starting from the date of commercial operations.[75]

Project construction began on April 2009 following a near 2-year delay due to the tragic collapse of the I-35 Bridge in August 2007.[70] The project later faced challenges with the ceramic coating of the turbines and sealing of the cable system causing excessive water leakage into the turbine generators. After these components issues were addressed with new installations, the facility was commissioned in December 2011.

The project received noteworthy praise due to efficiencies in its technology design and construction.[70] The dam utilizes a novel StraflowMatrix combined turbine generator technology that is designed to work efficiently in low head environments and can be effectively placed in existing dam structures. These design updates showed that existing dam sites previously considered uneconomical based on traditional technologies can be economical with turbines that work efficiently inside low head areas. The technology's seamless integration within the existing dam reduced overall project costs by eliminating activities such as excavation, full-scale powerhouses and new dam construction. The Minnesota Public Utilities Commission affirmed the facility's conformity to the state's renewable energy standards and actively uses the dam to increase public awareness of hydropower.

Based on lessons learned from this project, the developers recommend for future deployments of hydroelectric technology to assess potential component issues, updated equipment costs, site-specific development costs, and current electricity prices.[70] The developers advise future NPD electrification projects to incorporate new turbine coatings to avoid similar leakages to Lower St. Anthony Falls. The dam marked the first U.S. installation of StraflowMatrix technology that can be observed, visited and studied by other developers. Project schedules and budgets should also account for potential design risks in selecting new equipment as well as additional time required to meet USACE's specific design and construction standards. Lastly, the developers advised future electrification projects to be pursued when market prices are favorable to secure long-term PPAs. Lower St. Anthony Falls had to settle with a 15-year PPA, which is comparably shorter than the PPAs of most hydropower projects, as the developers were negotiating contracts at a time when electricity prices were volatile

The developers noted that support from state and federal programs was essential to project economics – RDF funding, REPI payments and federal stimulus grants contributed to the project's overall economic viability.[70] The developers also highlighted that the strong public-

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[74] https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7B24C4477D-767E-493A-A116-14F67ECF10A3%7D&documentTitle=20122-71134-01

[75] https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={CCE1E618-71D5-4D4F-91BA-5B3C9ABCADC7}&documentTitle=4728808

private partnership, cooperation with all involved agencies and parties, and early regulatory outreach were instrumental to the project's successful completion. Brookfield indicated that it would use the Lower St. Anthony Falls experience to inform decision-making and economic analysis of future development of existing dam sites for hydropower generation.

7. Braddock Hydroelectric Project

Still in its development stages, the Braddock hydroelectric project offers insight as to how the overlong development timeline for NPD electrification remains a significant barrier to investment. This barrier is particularly pronounced for small, private non-utility developers that lack sponsorship of private equity or debt, as shown in the case of Braddock's developer Hydro Green Energy.

The 5MW Braddock project is the hydropower retrofit of an existing lock and dam on the Monongahela River near Pittsburgh.[76] The site is just one of 23 locks and dams (all owned by USACE) in the Pittsburgh metropolitan area. Prior to 2011, developers pursued and later dropped plans to power existing dams in the Pittsburgh area due to a lack of investor interest and significant development risks. For example, Lower St. Anthony Falls developer Brookfield Power abandoned plans to develop hydropower at 14 sites in the Ohio River Basin after deciding that the projects were not financially viable.

In 2015, Hydro Green Energy ("HGE"), a privately held hydropower project development company, filed the FERC license application for the Braddock project, spearheading NPD electrification in the Pittsburgh area.[77] HGE developed and installed the nation's first commercial, FERC-licensed hydrokinetic (zero-head) power plant, the 4MW Mississippi Lock and Dam No. 2. With the Braddock facility, HGE aspired to showcase that the Pittsburgh area can serve as an optimal location for low-head, low-impact hydropower. In July 2015, HGE received the 50-year FERC license for the Braddock project. Unfortunately, the Braddock project remains in the limbo of its late development stage, which has taken nearly six years to date.

In a September 2019 project update summary, HGE notified that almost all necessary licenses, permits and articles from FERC and the State of Pennsylvania were finalized.[78] The project required a single final permit from USACE, to be made available at financial close. The project update indicated that HGE made significant progress in securing PPAs, construction debt and project financing. HGE received a PPA term sheet from a new customer, noting that it was drafting the final documentation for execution. HGE also stated that it had entered into

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[76] https://www.post-gazette.com/business/powersource/2015/12/26/Developers-of-hydro-plants-see-role-in-Pittsburgh-region/stories/201512260010
[77] https://www.hydroreview.com/world-regions/ferc-license-received-for-5-25-mw-braddock-locks-and-dam-hydro-project/#gref
[78] http://files.dep.state.pa.us/Energy/Office%20of%20Energy%20and%20Technology/OETDPortalFiles/GrantsLoansTaxCredits/PEDA/9-18-19/Hydro_Green_Energy_Presentation.pdf

negotiations on a second PPA term sheet with a local university. Lastly, HGE specified that Allegheny County issued a request for proposal for run-of-river hydropower. HGE placed a bid into that request and was shortlisted with discussions still ongoing. The names of the investors, PPA customers and banks were all kept confidential in this project update.

With regard to project financing, the update summary stated that HGE received two construction debt term sheets from two banks, each offering to finance 100% of the debt portion of the development costs.[8] According to the debt term sheets, the current capital structure consists of $8.6 million of equity (including grants) and $14.1 million in construction debt, adding to a total of $22.7 million in development costs. This total was up from $15.7 million that was projected earlier in October 2015.[79] HGE had ongoing discussions with multiple banks to discuss the optimal combination of debt, equity, terms, fees and interest rates for the project's capital structure.

HGE received $6.3 million in grants from federal and state authorities although no indication was made whether the grants applied specifically to the Braddock project. This total includes a $1.8 million grant from the U.S. Department of Energy, a $4 million grant from the Pennsylvania Alternative and Clean Energy Program and $0.5 million from the Pennsylvania Energy Development Authority.[79] The ITC for the project was valued at approximately $6.8 million, or 30% of construction and real property costs. HGE highlighted that the ITC grant was instrumental in securing financing, stressing that the project would not be economically viable without the grant.

Following financial close, the construction period is estimated to take 12 to 15 months.[77] HGE provided an updated timeline with construction slated to finish around December 2021 and commercial operations to commence around March 2022. The proposed financial close of the construction loan was estimated for July 2020 although HGE did not provide a public disclosure to affirm this milestone.

Despite its developmental woes, the Braddock facility stimulated significant discussion on the benefits and challenges of retrofitting existing dams in Pennsylvania. The Pennsylvania Environmental Council ("PEA") currently supports NPD electrification projects as they are considered to be much less environmentally intrusive than new dam construction.[80] However, the PEA acknowledges several challenges to broader adoption of hydropower in the state, including (i) electricity from competing sources in Pennsylvania has been relatively cheap, particularly natural gas which is abundant in the state, and (ii) the lengthy and complex process of permitting and licensing hydropower. The time from conceiving the project to generating power in Pennsylvania typically ranges from five to ten years. Even ten years is considered a significantly

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[79] https://archive.triblive.com/business/local-stories/braddock-locks-and-dam-hydropower-plant-project-off-to-slow-start/
[80] https://www.post-gazette.com/business/powersource/2015/12/26/Developers-of-hydro-plants-see-role-in-Pittsburgh-region/stories/201512260010

long time for investors to commit capital without certainty that the project will even reach construction. Furthermore, many developers start the permitting process, complete the substantial number of required environmental studies yet run out of capital along the way. These developers must raise sufficient capital to last the projected 10-year timeline to reach operations and budget additional time for potential project delays. HGE is facing similar issues with its overly protracted timeline causing difficulties to finalize project finance and commence construction for the Braddock project.

8. Rye Development Hydroelectric Projects (Allegheny No. 2, Emsworth, Overton)

The final case study explores the NPD portfolio of a leading U.S. hydropower developer, focusing on three of its largest projects and their respective journeys towards commercial operations. The case study also examines the developer's recent landmark private financing round and how the milestone can catalyze future large-scale private equity investments into NPD hydropower development.

Rye Development operates as a leading renewable energy project developer in the U.S., specializing in low-impact hydropower energy generation and energy storage.[81] Rye's current renewable asset portfolio consists of 22 hydroelectric projects at existing NPDs across Kentucky, Louisiana, Mississippi, Ohio, Pennsylvania, and West Virginia as well as two pumped storage projects in Oregon and Washington. All of Rye's NPD projects are FERC-licensed with capacities ranging from 5MW to 40MW. Rye targets existing dams due to their consistent flows, high plant factors, predictableness, and standardized configurations. Rye utilizes a clustering strategy when developing and retrofitting existing dams – it co-develops dams in the same geographic region to enjoy projected cost savings of 5-25% on construction and components.[82] Rye targets commercial, governmental and institutional customers as potential off-takers, particularly those with mandates to consume low-carbon electricity.

In January 2021, Rye announced its strategic partnership with Climate Adaptive Infrastructure ("CAI"), an infrastructure investment firm specializing in low-carbon assets in the energy, water and transport sectors.[81] Under the partnership, CAI will finance the construction of its 22 NPD electrification projects, the majority of which are owned and operated by USACE. The partnership aligns with CAI's objective to fund large-scale, low-carbon infrastructure projects to withstand the global climate crisis. Rye also welcomed CAI's access to sustainable infrastructure investments as well as its industry expertise of renewable energy asset operations and policy in the energy and environmental sectors.

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[81] https://www.businesswire.com/news/home/20210114005598/en/Climate-Adaptive-Infrastructure-Funds-Hydroelectric-Projects-at-22-Existing-Non-Powered-Dams
[82] http://rrva.org/02242020/L&D%20Hydropower%20Initiative.pdf

The 22 NPD sites have a total capacity potential of nearly 250MW.[83] CAI intends to invest up to $150 million in equity capital, with federal tax credits and debt accounting for the remainder of the $800 million total investment. The projects were proposed years ago but have been slow to advance towards construction due to roadblocks in permitting and financing. Rye made requests to FERC to extend deadlines to commence construction under its licenses to sell power. CAI anticipates that other NPD retrofit projects will gain momentum as energy consumers such as tech companies seek renewable energy following pledges to reduce their carbon footprint. See below additional detail on three of Rye's NPD electrification projects:

a) Allegheny No. 2 Hydroelectric Project

This 17MW NPD retrofit project is located on the Allegheny River in the Pittsburgh metro area.[83] Rye currently has ten planned hydroelectric facilities along the Allegheny, Ohio and Monongahela rivers in Southwestern Pennsylvania and West Virginia.[84] The Allegheny No.2 project, however, marks the first hydroelectric power development on the Allegheny River in almost 30 years.[85] Rye received FERC approval for Allegheny No. 2 in March 2017 and the total development cost for this single project is estimated to be between $40 to $60 million.

University of Pittsburgh signed a PPA to purchase 100% of the electricity generated from the Allegheny No. 2 facility to power its Oakland campus.[94] This supply will power 25% of the campus' electricity needs. The university recently pledged to have 50% of its electricity supply generated from renewable sources by 2030. The institution will also utilize this facility as a learning center for on-site classes, renewable energy education for the public, and university outreach. Rye is currently targeting partnerships with local institutions, companies and organizations to purchase electricity from the ten planned hydroelectric facilities. University of Pittsburgh became the first to actually sign a PPA (with the PPA term length to be determined). Rye emphasized that contracts with power purchasers are necessary to finance and build the remaining facilities. The hydropower plant is projected for completion and to start generating power by 2022 and will be located less than five miles from the Oakland campus.

b) Emsworth Hydroelectric Project

This 18MW low-impact hydropower facility will be built at the existing Emsworth Locks and Dam site on the Ohio River just 13 miles from Rye's Allegheny Lock and Dam No. 2 project.[83] Rye is currently working through the permit process with USACE and expects construction to begin in late 2021, which can foster up to 200 local jobs.[86] The facility is

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83 https://www.ryedevelopment.com/projects/
84 https://www.spglobal.com/marketintelligence/en/news-insights/trending/2zjfdod_zy1gbibvwhn4pg2
85 https://www.utimes.pitt.edu/news/pitt-signs-agreement
86 https://www.post-gazette.com/local/region/2021/01/28/Allegheny-County-government-hydroelectric-generation-Emsworth-Locks-Dams-Ohio-River-Rye-Development/stories/202101280159

expected to be operational by mid-2023. Rye will likely rely on CAI's investment funding and money raised in the financial markets to cover development costs for the Emsworth project, which are estimated to be in the $50 million range.

In January 2021, Allegheny County entered into a 35-year PPA with Rye to purchase power from the Emsworth facility.[86] The County estimates to purchase roughly 40% of the plant's generated electricity, which will be used to power municipal operations and buildings such as the Allegheny County Jail and the Allegheny County Courthouse. Rye will sell the remaining 60% of the facility's output to other local customers, although no indication has been made as to whether PPAs were secured.

Allegheny County currently purchases the majority of its electricity through a consortium that, beginning in 2021, shifted to make its energy purchases from 100% renewable sources.[86] The County began moving towards this renewable energy goal by issuing an RFP in April 2019 to hydropower developers, eventually issuing an informal intent to award Rye Development. County leaders expect the arrangement to generate savings over the long-term as it provides "a fixed rate and stability in county expenses". Through the arrangement, Allegheny County hopes to signal to other stakeholders in the community that new hydropower on existing dams will deliver consistent cost-effective clean energy while spurring investment into local infrastructure.

c) Overton Hydroelectric Project

Located on the Red River in Louisiana, this NPD electrification project will be built on the existing USACE-owned Overton Lock and Dam.[83] At 52MW capacity with an estimated development cost of $130 million, the Overton facility is currently at the top-end of Rye's hydroelectric portfolio[87]. The dam was initially built in 1982 to incorporate hydroelectric generation although electricity-generating equipment was never installed.[88] Thus, the design and construction of the new power facility will fulfill the dam's original intention.

In November 2015, through its previous entity FFP New Hydro, Rye acquired Red River Hydro, the owner of the FERC hydropower license for the Overton Lock and Dam project.[87] The original FERC license was issued in 2014. FFP Hydro / Rye estimated 200-300 jobs to be created through Overton's construction, operations and maintenance.[82] FFP New Hydro acquired the project to expand its hydroelectric portfolio, realize synergies with other NPD retrofit projects and benefit from economies of scale. At the time, FFP New Hydro was sponsor-backed by US Renewables Group, a renewables focused investment management firm with over $750 million of capital under management, and Crestline Investors, an institutional alternative investment management firm managing over $10 billion.[87]

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[87] https://www.theadvocate.com/baton_rouge/news/business/article_29bbde5e-dc57-5a96-b78a-7c40ee7486fa.html
[88] https://apps.dtic.mil/dtic/tr/fulltext/u2/a328474.pdf

With an expected 75-year asset life, the project qualifies for 30% ITC and 100% bonus depreciation.[82] In a February 2020 project update, Rye notified that there was significant customer interest in Overton's output. However, the Overton facility has yet to secured a PPA. The commercial operation date for this facility is targeted for 2022/2023.

H. Rye Views Project Development Timeline as a Significant Barrier to Investment

Rye Development views the development timeline for NPD electrification as a significant barrier to investment.[82] Hydropower currently has the longest average time to reach commercial operations at ten years compared to solar at one year and wind at four years. This disparity in timelines among renewable energy sources can potentially dissuade investment in hydropower. Development stage investors will effectively not earn a return on capital for at least eight years, which further discourages project financing in this sector.

The development process for NPD electrification consists of four stages: (i) early stage development, (ii) late stage development, (iii) construction, and (iv) operations.[82] Early stage development typically lasts over five years and ends when the developer obtains the coveted FERC license. This stage is perceived as being "capital-scarce" and expensive with the binary risk of being awarded the FERC license. The timeline is considered to be long and uncertain with a notable lack of transparency from FERC. Developers often have limited data or reference points to navigate through this stage, with equally limited investor experience in securing project financing.

Afterwards, the project proceeds to late stage development, which typically takes over two years. At this stage, the developer has greater access to capital after securing the FERC license but must face additional costs to complete USACE's Section 408 review requirements.[1,82] USACE reviews each individual dam site separately even if the projects are clustered together based on geographic location, standardized configuration and similar technologies. Fees are incurred for each dam site assessment, which can significantly escalate total costs for developers with large hydroelectric portfolios such as Rye. During late stage development, PPAs are also initiated, negotiated and finalized with potential power purchasers. Once the Section 408 requirements are met, USACE will issue a Notice to Proceed to enter the construction phase.

The construction phase can take over two years and can be subject to project delays primarily due to flooding.[82] Projects that are in-construction and have secured long-term PPAs garner much greater investor interest compared to projects in the previous stages due to the security of long-term cash flows pledged by the off-taker. The construction phase can provide the opportunity for investors to earn higher returns than in the operations phase due to higher costs of equity/debt to compensate for development and construction risks. Furthermore, with relatively few NPD electrification projects in construction, project scarcity can actually stimulate institutional investor interest. Investors seeking potentially high returns from projects with PPAs look to quickly make investments before there are no more in-construction projects in the market. Construction concludes once the project is tested and commissioned after which it proceeds to commercial operations.

The final stage of operations is equal to the projected asset life of the hydropower facility, which can last anywhere from 50 to over 75 years.[82] This stage is marked by high scarcity value due to few completed projects in the market, driving competition from institutional investors to make investments in these facilities. The phase is also marked by long-term stability: the PPAs offer predictable cash flows to its investors and the facilities provide stable and reliable energy production to its off-takers.

I. Suggestions for Improving Future Hydropower Project Economics

The following recommendations to improve hydropower project economics were based on project financing trends, market drivers, development patterns, and financing challenges examined throughout the case studies. Despite differences in size, scale, location, project development and off-take agreements, these eight case studies highlighted overarching themes of regulatory hurdles, minimal government support, inability to access low-cost financing, price competition and lack of investor awareness towards the financial economics of NPD hydropower development. Developers and government authorities each have a unique set of recommendations to consider whose execution can enhance NPD retrofit projects and their ability to obtain project financing.

Developers face a series of suggestions that should be considered sequentially. First, hydropower developers should cluster, or simultaneously develop, several small-scale NPD projects into a single portfolio to improve their bankability to investors. A portfolio of multiple projects can help minimize geographic and development risks, achieve economies of scale and realize cost savings to attract low-cost financing. Second, these portfolios should be strategically positioned in locations where there are corporations, institutions and municipalities with strong renewable energy mandates and an appetite for low-carbon electric generation. Third, once project financing has been secured and projects reach operations, the investment details should be disclosed in the form of financial literature to increase investor awareness on NPDs. The literature can be marketed to investors (as well as the general public) to stimulate interest in financing future NPD electrification. Developers and investors can also capitalize on recent public and private sector investment milestones (e.g. Red Rock public debt raises, CAI's $800 million private capital commitment) to support their outreach and project finance analyses.

Federal, state and local government authorities should also adopt policies that (i) focus on modernizing and streamlining the licensing and permitting processes for NPDs, (ii) expand current tax credits on renewable energy development, (iii) invest in modernizing current infrastructure, (iv) preserve tax-advantaged and subsidized financial instruments and (v) introduce green banks to add depth to existing green project financing markets. If developers and government authorities were to execute these strategies and leverage the momentum of recent large scale NPD financing events, project financing for NPD electrification can eventually become inexpensive, expeditious and commonplace. More details regarding these suggestions are explained below:

1. Cluster Small NPD Projects into a Single Portfolio

The co-development of several NPD hydroelectric facilities within a close time frame by a single company can improve the projects' overall access to financing. From 2006 to 2017, half of the total 58 licensed NPDs were being developed as part of a cluster strategy, where a project developer retrofits multiple NPDs simultaneously.[1] In these cases, two to six NPDs located on a single river system are targeted to enable cost savings through economies of scale and cost/time synergies during the development and construction stages.

The cluster strategy was successful for AMP who secured nearly $3 billion in public debt funding for its portfolio of NPD projects that were developed simultaneously along the Ohio River Basin.[21] The 2016 and 2017 public debt transactions marked the largest NPD financing raises to date. The bond raises were eventually oversubscribed (or upsized) from their original intended amount due to strong investor demand. The strategy helped the projects reach successful commission within the targeted development timeframe.

Eagle Creek Renewables employs a similar cluster strategy for its NPD electrification developments.[89] The developer noted that a large portfolio of facilities can (i) reduce operating expenses via synergies among plants; (ii) attract interest from more risk-adverse financing sources due to the larger transaction size, (iii) drive down financing costs due to competition from multiple investors seeking to invest in the projects, and (iv) face smaller relative expenses as fixed costs such as legal, technical and market studies do not scale with portfolio size.

The cluster strategy can help mitigate development and geographic risks and attract diversified low-cost financing options. Pooling hydropower assets across different geographic and hydrologic regions can lower their risk profile to investors by diversifying exposure to a single market or abnormal climate pattern.[13] For the clustering of smaller, high-risk projects, developers can offer long-term contracting of new hydropower generation (e.g. PPAs) in exchange for preferential financing.

Despite the benefits, there are no significant cost savings associated with clustering projects from a license or permit application standpoint.[1] Current initiatives to streamline the license and permitting processes can resolve current cost issues incurred by developers, helping them to apply their savings to other cost-intensive portions of project development.

[89] https://efiling.energy.ca.gov/GetDocument.aspx?tn=234752&DocumentContentId=67611

2. Strategically Position NPDs Near Power Purchasers Interested in Hydropower

Several of the nation's corporations, universities, cities and municipalities have recently made commitments to power their facilities and communities mostly (or even entirely) with locally sourced renewable energy. Some of their sites stand in close geographic proximity to existing dams and other waterway infrastructure with significant hydropower potential. NPD developers can leverage this unique position and strategically target hydropower development at dams near these companies, institutions and cities to fulfill their energy demand and sustainability objectives.

For example, many of the large technology companies (e.g. Apple, Amazon, Facebook and Google) operate massive data centers in Oregon, which is home to a large number of existing dams and irrigation canals with strong hydropower potential.[90] These tech firms are drawn to the state's low power prices and tax exemptions.[91] As these data centers consume significant amounts of electricity to house critical applications and data 24/7, their owners are keen to explore alternative sources of energy for low-carbon power consumption.

In April 2014, Apple acquired a hydroelectric project built on an existing irrigation canal located in Central Oregon.[92] The facility's hydroelectric output will be used to power Apple's Oregon data centers as Apple pledged to power these facilities entirely with renewable energy. All of Apple's data centers currently utilize locally sourced renewable resources including wind, hydro and solar for power. Similarly, Amazon's data centers in Morrow and Umatilla counties in Oregon draw hydroelectricity from dams situated along the Columbia River Basin.[93] Outside of Oregon, Yahoo and Verizon are harvesting low-cost hydropower from the Niagara Hydroelectric Power Plant for its data center facilities in Upstate New York.[94,95] These examples show that existing and future data centers can utilize neighboring dams and waterways to generate clean energy, lower electricity costs and comply with corporate ESG standards.

Universities have followed similar pathways to fueling its buildings and facilities with hydropower. The aforementioned case studies highlighted the Mahoning Creek and Allegheny No. 2 hydroelectric plants as two examples of projects whose off-takers are universities (e.g. Penn State and University of Pittsburgh respectively) that are purchasing hydroelectricity from nearby dams. Others include Villanova University who, in April 2020, signed a multi-year PPA with ENGIE Resources, whereby 50% of the energy purchased will be sourced from the Holtwood Hydroelectric Power Plant.[96] Operating for nearly a century, the Holtwood facility is

[90] https://www.datacenterknowledge.com/archives/2015/02/11/viawest-building-massive-oregon-data-center
[91] https://datacenterfrontier.com/portland-electricity-low-data-centers/
[92] https://www.datacenterknowledge.com/archives/2014/04/14/apple-buys-hydro-power-facility-near-prineville-data-center
[93] https://www.oregonlive.com/silicon-forest/2019/10/oregon-law-puts-small-towns-in-a-bind-when-big-tech-demands-huge-tax-breaks.html
[94] https://www.hydroreview.com/dams-and-civil-structures/low-cost-hydropower/#gref
[95] https://www.nypa.gov/news/press-releases/2010/20101026-verizon-niagara
[96] https://www1.villanova.edu/villanova/media/pressreleases/2020/0427.html

located on the Susquehanna River and is currently owned by Brookfield Renewable. Villanova pursued the PPA as part of its commitment to achieve carbon neutrality by 2050.

Outside of Pennsylvania, University of Notre Dame is currently constructing a 2.5MW hydroelectric generation facility on an existing dam site in the St. Joseph River in downtown South Bend.[97] Notre Dame holds the FERC license to the facility, which has been in construction since August 2019 and is slated to finish in Fall 2022. The hydroelectric plant will help supply 7% of the campus's electrical needs and cut the university's carbon footprint in half by 2030. In January 2020, Clarkson University in Upstate New York reached an agreement to purchase over half of its electricity needs from Brookfield Renewable.[98] Clarkson's Potsdam campus is now supplied by 100% low-carbon energy, consisting of locally sourced hydropower and solar power. Universities all across the country can take similar approaches to scan their local environment, identify nearby dam facilities and secure PPAs to meet their energy needs with hydropower.

Lastly, cities and municipalities can leverage utility-scale NPD electrification to power their communities with clean hydropower. For example, as discussed in the case studies, Allegheny County in Pennsylvania and the City of Hamilton, Ohio are purchasing locally generated hydropower from NPD projects (e.g. Emsworth and Meldahl facilities respectively). Offsite PPAs allow local governments to purchase energy from utility-scale projects that are cost-effective compared to other procurement options.[99] These PPAs can be attractive to cities located in deregulated electricity markets that allow for retail electricity choices.

Since 2015, over 150 U.S. local governments have closed renewable energy deals and even more have committed to ambitious renewable energy goals.[100] Hydropower can be a suitable clean energy source for these communities if they are in close proximity to water systems with strong hydropower potential. Cities such as Aspen, CO, Burlington, VT, Palo Alto, CA, and Seattle, WA receive a significant portion of their total energy supply from locally sourced hydropower at 45%, 50%, 50% and 86% respectively.[101,102,103] Other cities can also accelerate their large-scale renewable energy procurement by sourcing energy from existing NPD sites to green their portfolios and avoid construction costs of building their own generation. Developers can strategically position NPD development near cities with strong decarbonization commitments that can secure long-term PPAs to meet their clean energy needs.

[97] https://facilities.nd.edu/projects/current-major-projects/hydroelectric-plant/
[98] https://www.clarkson.edu/news/clarkson-university-campus-now-powered-100-percent-renewable-electricity-through-partnership
[99] https://www.rila.org/blog/2019/01/are-offsite-ppas-right-for-your-company
[100] https://www.pathto100.org/five-trends-u-s-cities-and-counties-are-going-renewable/
[101] https://energysolutions.seattle.gov/wp-content/uploads/2018/03/Green_Up_product_content_label.pdf
[102] https://content.sierraclub.org/creative-archive/sites/content.sierraclub.org.creative-archive/files/pdfs/1352%20RF100%20report%2005_web-08-2016.pdf
[103] https://slate.com/business/2014/09/palo-alto-power-supply-how-the-home-of-stanford-became-carbon-neutral.html

3. Market Hydropower's Favorable Economics and Investment Returns

Alternative hydropower projects such as NPDs can be highly cost-effective in their operating stages. These projects are able to recoup their financing costs before the end of their actual service life.[8] The facilities have effectively no fuel costs, utilize robust and innovative equipment, and face very low operating costs once the debt service is paid. For a small hydropower project, the cost of power drops to less than $1/MWh while the costs for larger scale projects drop to less than $0.5/MWh, benefitting from economies of scale. As hydropower is a relatively mature form of renewable energy, the electrical facilities themselves do not require significant cost or performance improvements throughout their asset lives.

Hydropower is currently the cheapest type of energy to run – the average total price to run a dam is $0.0085 per kWh, compared to $0.0210 for fossil fuels, $0.0180 for nuclear, and $0.0370 for natural gas.[104] To off balance the cost of hydropower, dams must generate revenue, which is typically a function of current energy prices. These prices depend on location, which vary state by state, and are subject to inflation and market volatility. Even such, dams generate on average a profit of over 1,500% when factoring in the cost of operations and maintenance. However, dams must overcome their initial capital cost, which often results in a very low internal rate of return ("IRR"). A high power output will typically give investors an 8% IRR, while a low power output will only yield about a 2% IRR. Fortunately, the IRRs can double or more in situations where the infrastructure is already in place, as in the case with NPDs.

In July 2013, USACE conducted a hydropower resource assessment on existing NPD sites.[105] The study determined the optimal IRRs for the Allegheny Lock and Dam No. 2, Emsworth Locks and Dam, and Overton Lock and Dam to be 9%, 11% and 12% respectively during their pre-construction stages. This paper's case study on the Mahoning Creek Dam indicated a project IRR of 8%, as shown in the original FERC licensing application. This project IRR range of 8-12% for NPDs is above the 8% baseline IRR for traditional new dam construction with high power outputs. Developers can highlight these above-average IRRs in their marketing efforts to attract project financing from investors.

Still, the 8-12% range may not suffice for some investors targeting much higher investment returns.[93] To resolve this, developers can seek opportunities to replace obsolete equipment and introduce technological advancements to improve operability, efficiency and environmental performance. The majority of NPD retrofit projects takes place in sites that are several decades old, making them excellent candidates for refurbishments and upgrades. Private equity sponsors actively seek opportunities to acquire renewable energy assets at low market prices, realize cost savings and maximize power generation efficiencies through system and

[104] https://medium.com/@vpoluru3/alternative-hydro-energy-generation-ecd1025c2b3c
[105] https://www.hydro.org/wp-content/uploads/2014/01/Army-Corps-NPD-Assessment.pdf

technology improvements.[106] Through less expensive construction techniques, use of advanced materials and reduction in cost of electrical components, these sponsors can lower development costs and realize higher project-level returns.[8] These opportunities can then be marketed to investors who would have otherwise reconsidered investing in NPD projects.

4. Capitalize on Recent Hydropower Investments to Raise Awareness

CAI's $800 million capital investment in Rye's NPD portfolio represents one of the largest private financing rounds for NPD hydropower development.[107] Rye and several other NPD developers anticipate that CAI's investment will serve as an impetus or catalyst for future privately sourced financings in the NPD development sector.

Rye has also been actively attracting private capital across other alternative forms of hydropower: in November 2020, Copenhagen Infrastructure Partners ("CIP") acquired ownership of Rye's Swan Lake and Goldendale closed-loop pump hydro storage projects.[108] CIP is one of the world's leading energy infrastructure funds with more than EUR 12 billion in commitments under management. CIP's current investments in energy infrastructure assets include onshore/offshore wind, biomass and solar PV investments.

Originally developed under a joint venture between Rye and National Grid, the Swan Lake and Goldendale projects were acquired to fulfill CIP's strategy in accelerating renewable energy investments in North America. CIP specifically targets investments with highly stable cash flows, which Swan Lake and Goldendale are projected to generate during their asset lives. The projects also received strong state support as Washington and Oregon (where both projects are located) share a commitment to move towards 100% clean electricity. Given the long-term investment horizon of its funds, CIP can actively participate in the contracting, de-risking, financing, construction, and operations of the two projects.

The CIP acquisition can potentially open doors to more European-based infrastructure funds to invest in U.S. hydropower projects including NPDs. European funds have financed low-carbon energy assets such as hydropower for decades and can use their vast access to capital and project development expertise to both finance and manage NPD projects.[109] With experienced developers such as CIP at the helm to mitigate development and financial risks, potential power off-takers will likely feel assured to sign PPAs to secure long-term hydroelectric output.

Given that growth in small-scale hydropower and its project financing has been relatively modest in recent years, recent large-scale investments such as CAI and CIP can provide much-needed awareness to this high-potential renewable energy. Investors usually evaluate project

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[106] http://d1c25a6gwz7q5e.cloudfront.net/papers/download/PrivateEquity04262006.pdf
[107] https://www.ft.com/content/cf60d1cf-96d5-44cc-bd5c-daf5174bf4a2
[108] https://www.ryedevelopment.com/newsentry/cip-acquires-swan-lake-and-goldendale-393-mw-and-1200-mw-pumped-storage-hydro-projects-located-in-oregon-and-washington-usa/
[109] https://www.irena.org/publications/2018/Feb/Renewable-energy-prospects-for-the-EU

financing based on comparable historical transactions to determine discount rates and overall project valuation.[13] The CAI and CIP investments can provide valuable financial data to which other infrastructure and renewable energy investors can leverage into their valuation and assessments of similar hydropower projects and make informed investment decisions to drive future project financing.

5. Streamline Licensing & Permitting Approvals

Investors often turn away from financing NPD electrification due to the lengthy licensing and permitting approvals needed to start the development process. To obtain a FERC operating license, a developer must research or produce environmental data for each individual dam site to be electrified (even if neighboring dams share physical similarities and/or are co-developed under a cluster strategy).[110] The environmental studies and licensing costs are very expensive and can render the project economically unviable. These issues can be resolved through the following initiatives:

- Streamlining the licensing process for non-federal NPDs with less than 10MW of capacity to reduce the timeframe from intent submission to license issuance;[111]
- Introducing a two-phased synchronized process to obtain the FERC license and USACE Section 408 and 404 permits, which can shorten the regulatory process.[97] Typically, these processes are implemented sequentially, with median time elapsed from FERC licensing to construction lasting ~4 years. FERC and USACE can coordinate their environmental reviews and authorizations closely from the start to ensure that there are no duplicative studies. This cooperation can eliminate redundancies, maximize the extent of which reviews and approvals occur concurrently, and provide developers and investors with added certainty;
- Establishing and enforcing an overall schedule for all required authorizations under federal law for hydropower development.[112] A defined schedule is currently not in place, which contributes to the numerous uncertainties facing NPD projects. Empowering FERC to manage the entire authorization process and implement schedule discipline can realize time savings for NPD hydropower development.

FERC has already set the default term for original and new FERC licenses at non-federal dams to 40 years.[97] Previously, the license term decision was project specific with terms ranging from 30 to 50 years. This new FERC policy aims to reduce uncertainty for project developers and owners and the time for recovering the investment of obtaining a license.

[110] https://www.nrel.gov/docs/fy12osti/52409-2.pdf
[111] https://www.energy.gov/sites/prod/files/2018/04/f51/Hydropower%20Market%20Report.pdf
[112] https://www.hydro.org/wp-content/uploads/2016/04/4.20-Senate-Energy-Bill.pdf

6. Expand Federal Funding on Hydropower Projects

Federal funding for research, development and deployment is critical to support the growth of NPD electrification and overall hydropower throughout the nation. These initiatives to expand federal funding on hydropower include[22,113]:

- Providing expansions and extensions of federal subsidies such as the PTC, the ITC and guaranteed loan financing through programs such as the Rural Utilities Service Electric Program to improve NPD retrofit economic feasibility;
- Provide similar expansions and extensions to the Clean Renewable Energy Bonds ("CREBS") Program to finance future NPD and other hydropower development projects. The program offers tax-advantaged financial instruments when hydropower projects access public debt markets to raise capital;
- Fund operations and maintenance upgrades at existing USACE-owned dams;
- Restore full Build America Bonds and New Clean Renewable Energy Bonds subsidy payments used to finance NPD projects such as AMP's Ohio River projects. Due to budget sequestration, the federal government reduced subsidy payments, causing developers such as AMP to cover the interest difference and costing them millions. Protecting these subsidies will allow for developers to seek tax-advantaged instruments without the worry or burden that they will be subject to future sequestration;
- Pass the Water Power Research and Development Act that authorizes approximately $650 million in funding for hydropower, pumped storage and marine energy sectors over the next 5 years;
- Expand, reauthorize and fund Section 242 (which is oversubscribed at current authorization level) of the Energy Policy Act of 2005 for hydropower programs. The Section 242 incentive is designed to lower costs that can determine the viability of small hydropower projects such as NPDs;
- Increase funding for the DOE's Water Power Technologies Office (WPTO), which invests in technology RD&D for innovative standardized and modular approaches to hydropower development. These innovations can lower overall project costs and improve deployment time versus traditional projects at both greenfield sites and NPDs.

[113] https://www.energy.senate.gov/services/files/4DD12125-F110-499E-9845-2C1D403A9525

7. Increase State Recognition and Support of Hydropower

Another issue that inhibits hydropower development is its limited recognition as a renewable clean energy resource across state programs and local environmental markets. State renewable portfolio standards ("RPS") contain restrictions on the amount of hydropower that is eligible. These restrictions include project capacity limitations (30 MW or less), resource and technology limitations (e.g. existing infrastructure vs. no new dams), explicit operational or impact criteria (run-of-river, low-impact certified dams) as well as other requirements.[5]

Treatment of hydropower as a renewable resource is also not consistent from state to state, which complicates hydropower marketing especially those with multi-state dam portfolios.[13] Developers face similar inconsistencies and difficulties when needing to fulfill varying state permitting requirements before initiating construction. State uniformity across these varying RPS and permit requirements can help resolve these issues.

States can also add hydropower as an eligible project type to existing state loan, grant and tax-credit programs for water infrastructure. For example, the State of Colorado modified its existing water infrastructure-financing program to create a hydropower loan that can finance the construction of hydropower projects with loan terms of 30 years at an attractively low interest rate of 2%.[114] The state also has a small hydropower loan program that can lend up to $2 million at a similarly low interest rate of 2% for project construction with a maximum term length of 20 years. These programs ushered a flurry of new hydropower development, including 30MW of new construction in Colorado – a significant number considering the minimal amount of new hydro capacity currently being installed nationwide. The state of Oregon similarly offered the now-expired Business Energy Tax Credit in which hydropower projects qualified for a 50% nonrefundable credit of its certified project costs, of up to $10 million. The credit helped financed a number of irrigation canal hydropower installations in the state.

In addition to tax credits and lowering financing costs, programs at the state level can address regulatory barriers and financial risks that deter hydropower development. For example, in 2020, the State of Colorado and FERC signed a memorandum to streamline the permitting process for all small hydropower projects under 5MW.[115] As previously discussed in the Blue Heron case studies, the State of Vermont introduced the SPEED FIT program as a policy mechanism to encourage the deployment of small-scale renewable electricity technologies. SPEED guaranteed competitive long-term market prices for small hydropower projects such as Blue Heron, helping them to secure PPAs and attract private investment. States with significant NPD hydropower potential can enact similar FIT policies as only 12 states have these mechanisms currently in place. Furthermore, states should correspondingly conduct outreach and

[114] https://www.hydrofoundation.org/uploads/3/7/6/1/37618667/150422_final_blue_gold_report.pdf
[115] https://www.nrel.gov/docs/fy18osti/70098.pdf

educate stakeholders and investors on these available funding and regulatory programs to help increase awareness and further encourage project financing for hydropower.

8. Create State Green Banks to Add Depth to Project Financing

Green banks are a relatively new source for funding renewable energy projects, providing low-cost capital to both traditional and otherwise challenging market segments. Green banks are not literal banks, as they do not take in deposits.[102] Rather, these are specialty investment funds that provide capital to projects that could not have otherwise been completed. The purpose of green banks is to expand the renewable energy market by using attractive interest rates and financing products to leverage capital from the private sector and bridge the gap for smaller scale projects that are often excluded from commercial financing.[116]

Green banks seek to complement, not replace, existing financing institutions, serving renewable energy projects. By using credit enhancements and long-term debt, green banks help mobilize private investment in renewable energy and expand the pie of project financing markets across the nation. The funds receive the full-faith backing of their state governments, increasing the creditworthiness of these investments. There are currently ten states with green banks and the associated funding mechanisms in place.[117]

In Connecticut and New York, their state green banks are partially funded by proceeds from the sale of emission credits through regional carbon tax programs.[102] States can establish their own green banks using proceeds from carbon taxes, sales from emission credits or other levied fees such as surcharges on utility bills. Green banks can then leverage public funds to attract private sector investment towards clean energy and efficiency projects. Once the private funds are obtained, the goal for the banks is to provide and structure financing with low interest rates and long payback times that are suited for renewable energy projects such as hydropower.[118] These structures can help projects achieve savings in financing costs, provide pricing certainty and enable investors to achieve attractive investment returns.[119]

These green banks were initially established after states realized that many breakthrough technologies in the sustainability sector fall into a commercialization gap often called “the valley of death”. These technologies were either too capital intensive for venture capital or too risky for private equity, public or corporate debt financing.[102] More established renewable energy technologies such as wind and solar often suffered through high costs of capital caused by credit constraints in debt and tax equity markets.

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[116] https://acore.org/wp-content/uploads/2017/12/ACORE_USEPA_111d_Comments_12-1-2014.pdf
[117] https://static1.squarespace.com/static/59bc05f0c534a543a9f96b0d/t/5edf9fbd8285f063f6c13bbe/1591713732941/2020+Annual+Industry+Report+Final.pdf
[118] https://www.renewableenergyworld.com/baseload/green-banks-can-multiply-the-impact-of-clean-energy-financing/#gref
[119] https://www.nrel.gov/state-local-tribal/basics-green-banks.html

State green banks can focus on hydropower and address their short-term credit challenges when accessing debt and tax equity markets, accelerate project deployment, and ensure sufficient depth to project financing markets. Additionally, lower credit risks would allow state green banks to maximize private sector financing on an aggregate level. State green banks can also utilize a variety of financial instruments at their disposal including equity instruments, green bonds, green and sustainable loans, and sustainability-linked debt.[104] The variety and diversity of financial instruments can create innovative funding mechanisms that are specifically tailored to a project's financial, development and risk profile, especially those as nuanced as NPD electrification projects.

J. Conclusion

Retrofitting existing NPD sites to generate hydropower can provide clean renewable energy to corporations, academic institutions, cities, and municipalities across the country to help diversify their power portfolios and fulfill mandates for decarbonization. Despite cost advantages and favorable economics, investors are still hesitant to pursue project financing for NPD electrification due largely to a lack of awareness of these benefits, insufficient financial literature on project valuation and economics, a lengthy and complex regulatory process leading to project uncertainty, and minimal state and federal support. Investors fail to realize that these projects can potentially offer low operation & maintenance costs and stable cash flows due to long-term secured power purchase contracts – all of which are attractive investment profiles for most project financiers.

This paper focused on analyzing the case studies of fifteen NPD projects to illustrate the diverse characteristics of each project and their effect on securing project financing. The size, location, development strategy, project developer(s) and power purchase agreement were instrumental to whether the projects could secure financing through private equity, public or private debt, commercial lending, grants or a combination of all options. The projects all faced similar challenges in terms of regulatory complexities and indeterminate development timelines yet powered through these obstacles to realize the financial, economic and environmental benefits of hydropower to their communities. As more NPD hydropower development projects are developed, a greater understanding of their financing processes will evolve and provide much-needed awareness and financial literature for investors to assess future projects. Given that NPD development has already encouraged funding from the likes of institutional and retail investors in the public bond markets and infrastructure investment firms such as Brookfield Renewable and Climate Adaptive Infrastructure, there is a strong likelihood that NPD project financing can continue its expansion and potentially reach the 12GW threshold of new hydropower capacity.

Appendix 1: Project Financing Organizational Structure

The organizational structure for financing hydropower projects can be complex, involving multiple actors taking on multiple roles.[13] No single structure or set of actors applies to all hydropower projects. Most projects have some government involvement, such as an off-taker owned by the government, or strict regulations requiring project developers to employ local workers and suppliers.

The **project owner** is typically the most important actor in the hydropower project development process. Most of the top-level relationships and contracts are between the project owner and other key parties. The owners of hydropower projects include all equity investors, which can include renewable energy project developers, electric utility companies (including government-owned agencies) and private and public sector investors.

A **Special Purpose Company** ("SPC"), or Special Purpose Vehicle ("SPV"), is often established to develop and own private hydropower facilities, especially if the shareholders include a mixture of public and private sector investors. The SPC may comprise a consortium of interests, sometimes including the local government.

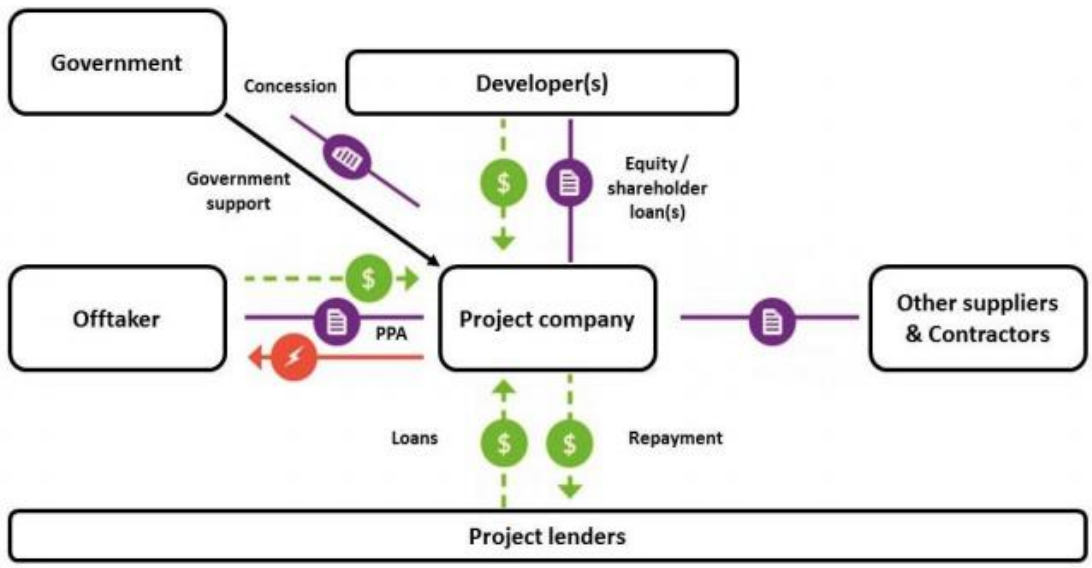
The project owner is frequently also referred to as the **"developer**" because of their role in planning and promoting the project, identifying off-takers, obtaining necessary permits and concessions, securing funding and PPAs, and running the project as the operator in the long term. Not all investors in the project consider themselves as developers as there may be equity investors who hold a minority stake.

Government agencies are responsible for issuing various licenses and permits required for the development of a hydropower project. These may include planning permission and building regulations approval, construction licenses, security clearance, water rights agreements, company registration, investment licenses, and the licensing of designers, contractors, manufacturers, plant operators and skilled labor. Obtaining all the necessary licenses can be both a laborious and a time consuming task for the project developer, especially if the licenses need to be acquired from various agencies, each with their own procedures and timelines.

The **off-taker** is the party that purchases the output of the hydroelectric project through signing a **power purchase agreement** ("PPA") with the project owner. A PPA is a legal contract between an electricity generator and a power purchaser/off-taker. PPAs play a key role in the financing of hydropower projects not owned by a utility as they secure the project's revenue stream. The seller under the PPA is responsible for maintaining the system while the purchaser only pays for the power produced. PPAs may also include clauses to detail acceptable price adjustments during the contract period.

The financing of a hydropower project typically involves a mix of actors and financial instruments, which can be combined in various ways. Financing packages can include debt or equity or both, but there is not a single financial structure or mix of actors universally applicable to all hydropower projects.

Typical Project Finance Structure[13]*:*



Project finance refers to financing where the project itself, rather than the assets of the wider company owner, serves as collateral. This is only possible when the lender can easily step into the borrower's shoes and continue the project in case the borrower defaults. To create such a set-up, a number of arrangements detailing the duties and obligations of each party in various 'what if' scenarios need to be in place for the construction period and operational phase. These arrangements must be included in the PPA and other ancillary contracts. All required licenses and permits, insurance policies, and other important contracts must be drawn up in such a way that the lender has suitable redress or, in an extreme case, can take over the project in the event of default.

Appendix 2: Available Funding Options for Project Financing

Financial instruments used for hydropower project finance typically come from equity finance (public or private), debt finance, commercial lending, and grants.[13]

Equity finance involves funding in exchange for a share of project ownership and thus a share of any future profits. Equity investors are prepared to assume some risk in return for higher rewards than lenders, making equity investments more expensive than debt. The risks and profits are shared among the shareholders according to their shareholding class. Typical return on equity (a measure of financial performance calculated by dividing the net income by the shareholders' initial equity investment) is 15-20% per year or more, depending on the perceived level of risk. Equity investment may be provided from public sources, private sources or a mixture of both. Private equity financing may come from investment funds, infrastructure funds, pension funds, private equity secondary funds, and insurance funds

There are broadly two types of **equity investors**. *Strategic investors* are organizations with significant experience, interest or prior involvement in hydropower projects (such as sector-focused investment funds, large utility companies that may also act as an off-taker for the project, independent power producers, or contractors). These investors often take an active role in the management and oversight of the projects in which they invest. On the other end are *financial investors* that consist of private equity funds, pension funds or insurance companies with varying degrees of familiarity with the hydropower industry. These financial investors tend to be risk-averse in their investment and take a passive role during project development.

Debt finance involves short- and long-term loans and bonds that are raised privately. Debt financiers and lenders provide funds at a defined interest rate for specified periods. Unlike shareholders, lenders are not owners of the project and therefore do not generally share in its risks or profits, although they accept the risk of project failure.

Commercial lending refers to bank loans and bonds raised on the capital markets. For large and risky hydropower projects, loans are often syndicated among a number of lenders to source sufficient funds and to distribute risks. The term Lead Arranger/Mandated Lead Arranger is used to refer to a bank that is mandated to syndicate various loans. The lead arranger is responsible for negotiating the terms and conditions (including the price), the tenor (repayment period) and the structure of the loan facility with the borrower. The lead arranger must share these terms with the other lenders to the project, rather than each lender negotiating individually.

Grants provide a type of financing that does not need to be repaid and does not require equity ownership in the project. As such, grant funding can relieve financial burdens from other investors or developer.

The relative proportions of debt and equity (otherwise known as the debt-to-equity ratio) is key to project financing. Low-geared hydropower projects (low debt-to-equity ratio) have a sizeable proportion of equity and thus require less debt, creating confidence among lenders as debt interest and repayments will always be paid before the equity holders in the case of default. The interest rate on a loan is generally lower than the rate of return on the total investment, meaning that the profitability of the investment increases with more debt. This leverage effect causes hydropower projects with a high debt-to equity ratio (highly-geared projects) to be more profitable than those with a low debt-to-equity ratio. Lenders tend to be highly risk-averse and focused primarily on protecting their loans. Legally, debt must be serviced before profits are used to pay equity returns. As a result, lenders are less exposed to risk than equity investors or shareholders and debt finance is usually less expensive than equity finance.

Appendix 3: Project Development Timeline[13]

BANK PERSPECTIVE	MAIN ACTIVITIES (DEVELOPER)
PHASE 1	**SITE IDENTIFICATION/ CONCEPT**
	• Identification of potential sites • Funding of project development • Development of rough technical concept
PHASE 2	**PRE-FEASIBILITY STUDY**
	• Assessment of different technical options • Approximate cost/benefits • Permitting needs • Market assessment
PHASE 3	**FEASIBILITY STUDY**
• **First contact with project developer**	• Technical and financial evaluation of preferred option • Assessment of financial options • Initiation of permitting process
PHASE 4	**FINANCING CONTRACTS**
• **Due diligence** • **Financing concept**	• Permitting • Contracting strategy • Supplier selection and contract negotiation • Financing of project
PHASE 5	**DETAILED DESIGN**
• **Loan agreement**	• Preparation of detailed design for all relevant lots • Preparation of project implementation schedule • Finalisation of permitting process
PHASE 6	**CONSTRUCTION**
• **Independent review of construction**	• Construction supervision
PHASE 7	**COMMISSIONING**
• **Independent review of commissioning**	• Performance testing • Preparation of 'as built' design (if required)

Source: Adapted from IFC (2015).