Evaluating New Business Opportunities for Interregional Transmission

by

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Abstract

The merchant transmission investment model is conducive to addressing interregional and long-range transmission needs as it provides a pathway to circumvent localized regional and state transmission planning processes and focus directly on interregional development. Furthermore, merchant transmission investments in accordance with comprehensive (multi-value) benefits planning provide a favorable benefit-to-cost ratio for transmission customers and support positive returns for investors. However, evaluating the comprehensive benefits of proposed transmission projects is computationally expensive and unfeasible to execute for early-stage, exploratory analysis of multiple projects. Therefore, this thesis focuses on the development and use of a computationally-reduced transmission business evaluation tool that heuristically evaluates critical components of comprehensive benefits and assesses merchant-based cost recovery viability of five interregional and long-range transmission projects on a forward-looking basis.

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In collaboration with the Transmission Fundamentals Team, my MIT academic advisors, Professor Marija Ilic, and Roy Welsch were integral to the graduate research project and thesis' success. Over the past year, they have assisted me in structuring sound engineering analysis and business development for interregional transmission projects. I am extremely thankful to have the support of their expertise and wisdom in this effort.

Finally, I give my utmost gratitude to my immediate family and the LGO community. My Mother urged me to follow in the footsteps of my late Father and pursue a graduate education. She often reminded me that education transformed the lives of our family and enabled us to gain understanding and opportunities in the wonderful world our God has provided us. Upon enrolling in the LGO program, I realized the value of such an education alongside my classmates, and it has bonded us together. Now, they too are my family.

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Acronyms

ACEG Americans for a Clean Energy Grid. 29

CEII Critical Energy/Electric Infrastructure Information. 98

DOE Department of Energy. 17, 18

EIA Energy Information Administration. 17

ERCOT Electric Reliability Council of Texas. 26

ESIG Energy Systems Integration Group. 21, 24

FERC Federal Energy Regulatory Commission. 19

IPP independent power producer. 62

IRP Integrated Resource Plan. 67

ISO Independent System Operator. 21

ITC Investment Tax Credit. 62

JTIQ Joint Targeted Interconnection Queue. 29, 45

LCOE levelized cost of energy. 35

LMP Locational Marginal Price. 38

LRTP Long-Range Transmission Planning. 22

MISO Midcontinent Indepedent System Operator. 21

NEET NextEra Energy Transmission. 24

NREL National Renewable Energy Laboratory. 38

OATT Open Access Transmission Tariff. 30

OPF optimal power flow. 42

PCM Production Cost Model. 41

POD Point of Delivery. 30

POR Point of Receipt. 30

PPAs Power Purchase Agreements. 57

PTC Production Tax Credit. 62

RFPs request for proposals. 29

RMS root-mean-square. 50

ROFR right of first refusal. 28

RTO/ISO Regional Transmission Organizations/Independent System Operators. 24

SAM System Advisory Model. 38

SCED Security Constrained Economic Dispatch. 41

SIL surge impedance loading. 51

SLOPE State and Local Planning for Energy. 39

SSL steady-state stability limit. 51

U.S. United States. 17

VFT variable-frequency transformer. 43

VRE variable renewable energy. 59

VSC voltage source converter. 43

WACC weighted average cost of capital. 62

Chapter 1

Introduction

1.1 Transmission Need for Decarbonization

The federal administration has set an ambitious goal for the United States to achieve net-zero greenhouse gas emissions by 2050. This goal is part of a broader strategy to combat climate change and transition the country towards a sustainable, clean energy future. The administration aims to reach net-zero emissions economy-wide, meaning all sectors including energy, transportation, and agriculture will need to drastically reduce emissions through a combination of cutting carbon output and implementing carbon capture technologies. Even more ambitious is the federal administration's goal of reaching a net-zero emissions electricity grid by 2035 [6]. For reference, the United States (U.S.) Energy Information Administration (EIA)'s report of the electricity grid for 2023 informs that emissions producing, fossil-fuel generation made up 60% of the electricity generation, and the remaining 40% came from renewable energy and nuclear sources [4]. Regardless of the likelihood of meeting the 2035 net-zero goal, the federal administration's focus and commitment to this effort signals that electric grid decarbonization is a national priority and immediate action is needed.

In fact, the Department of Energy (DOE)'s On the Path to 100% Clean Electricity report provides several actions that need to be addressed to achieve this level of grid decarbonization. Several of the actions work towards the deployment of new electrical transmission lines and associated infrastructure at a large scale. Moreover, one action emphasized the importance of proactive transmission planning as critical for enabling the energy transition. Another action specifies the need for significant investments in transmission to increase capacity to a level needed to access and deliver clean energy resources; in some scenarios, the transmission increase could be up to 190%. These actions and estimations are the result of a collective analysis of experts in the electrical power sector, and they all share a similar belief: transmission is the single most important enabling technology for decarbonization. More specifically, expanding the grid's transmission capacity enables access to renewable energy resources and supports the electrification of energy demand by connecting areas with available land and suitable resources for renewable energy generation to load centers.

1.2 DOE National Transmission Needs Study

The DOE issues a National Transmission Needs Study report every three years. The latest report was released in October 2023 and includes an expanded scope of considerations of both historical and anticipated future transmission constraints and congestion. The expanded scope reflects an understanding of the challenges and opportunities facing the nation's transmission infrastructure in the context of shifting energy demands and policy goals such as the net-zero emissions electricity grid by 2035. Furthermore, the Transmission Needs Study aligns with the federal administration's net-zero goal by identifying the critical role of enhanced transmission infrastructure in achieving decarbonization targets. By analyzing the current and future needs for transmission to support the integration of renewable energy sources, the study provides a roadmap for investments and developments necessary to transition to a cleaner energy system.

The intention of the National Transmission Needs Study was also to produce findings that help inform the planning processes that ultimately lead to investments for transmission infrastructure upgrades. The study found that the key factors driving the push for expanding the transmission network include the necessity for a more reliable and resilient grid, transmission congestion relief, new electricity generation interconnections, and the management of increased electricity demand. Ideally, these findings should be accounted for when conducting proactive regional and interregional transmission planning. Interregional transmission, defined as transmission infrastructure that spans different transmission planning regions and interconnections, is highlighted as the critical infrastructure for reinforcing grid reliability, resilience, and decarbonization efforts. Interregional transmission supports these efforts by enabling access to diverse, clean electricity generation sources, load and weather patterns across the country [22].

1.3 Evaluating New Business Opportunities for Interregional Transmission Thesis statement

Present-day interregional transmission planning conducted in accordance to Federal Energy Regulatory Commission (FERC)'s, the federal authority of transmission, regulations and orders, is challenging due to vague guidelines on planning procedures. As a result, transmission planning authorities have historically avoided interregional transmission planning and investments in favor of regional and state-confined transmission solutions. The merchant transmission investment model offers an alternative approach. The merchant transmission investment model is conducive to addressing interregional and long-range transmission needs as it provides a pathway to circumvent localized regional and state transmission planning processes to focus directly on interregional development. Furthermore, merchant transmission investments in accordance with comprehensive (multi-value) benefits planning provide a favorable benefit-to-cost ratio for transmission customers and support positive returns for investors. However, evaluating the comprehensive benefits of proposed transmission projects is computationally expensive and unfeasible to execute for early-stage, exploratory analysis of multiple projects. Therefore, this thesis focuses on the development and use of a computationally reduced transmission business evaluation tool that heuristically evaluates critical components of the comprehensive benefits of proposed transmission projects and assesses merchant-based cost recovery viability.

Five interregional and long-range transmission projects currently under development were selected for this evaluation. The transmission business evaluation of these projects has two parallel objectives. The first objective is to utilize merchant-based cost recovery mechanisms of energy arbitrage and capacity contracts to heuristically measure critical components of the comprehensive benefits of the projects. Comprehensive transmission benefit planning supports the development of transmission projects that provide favorable economic value for customers. The second objective is to directly assess the business viability of the merchant-based cost recovery mechanisms for transmission. A business-viable merchant investment in transmission must demonstrate that it can provide positive returns to investors without the bolstering of a regulated rate of return. The combination of these objectives aligns the federal administration's interest in developing critically needed interregional transmission in an economically efficient manner and merchant investor interest in making a positive return on transmission investments.

Chapter 2

Transmission Planning and Merchant Investments

2.1 Multi-Value Transmission Planning Literature Review

The general agreement in the power sector and transmission planning field is that a consideration of the wide range of transmission benefits leads to a more comprehensive value accounting of transmission investments and results in favorable economic value for the public. Elaborating on this further, leading reports specify that planning for the significant increase in transmission investment necessary for decarbonization of the electric grid requires pro-active, multi-value transmission planning. This section reviews such transmission planning reports published by Midcontinent Indepedent System Operator (MISO) and Energy Systems Integration Group (ESIG).

2.1.1 MISO Multi-Value Transmission Planning

As an Independent System Operator (ISO) MISO is a transmission planning entity that operates as a not-for-profit organization and ensures reliable, least-cost delivery of electricity across much of North America, including parts of Canada and the United States. MISO manages, operates, and ensures the reliability of the high-voltage transmission system [47]. Pertinent to this discussion, MISO has incorporated and documented a pro-active, multi-value transmission planning approach in its first-of-its-kind Long-Range Transmission Planning (LRTP) process. The initial execution of this process aimed to mitigate the significant impact on the future generation mix and the reliability of the system through the development and installation of a collection of transmission projects. More specifically, the motivation for the planning approach was a forecasted increase in renewable and clean energy generation that drove the need for rapid increase in transmission development for generation interconnection within the MISO managed regions of the electricity grid. The project planning efforts began in 2011 during the first year of the LRTP process that proactively considered transmission needs for the 10-to-20-year time frame. The resulting transmission project plans were conceptually different from earlier transmission development efforts as these new projects were required to demonstrate the ability to provide customers with multiple types of economic benefits. The transmission projects were suitably named MVP [48].

All of the MVP projects were evaluated by their ability to meet three primary objectives: reliably and economically support regional public policy needs, provide various types of regional economic benefits, and deliver a mix of regional reliability and economic value. Furthermore, the evaluation of the economic benefits of the projects was emphasized to ensure that they were a viable business investment [48]. The result of this effort created 17 MVP projects with an estimated 1.8-3.1 benefits-to-cost ratio and was widely considered a success in pro-active, multi-value transmission planning across the power sector industry.

Then in 2020, continuously changing generation resources from fossil fuels to renewable energy and increasing frequency of extreme weather events induced MISO to again conduct the LRTP initiative to address future challenges with a multi-value approach. The future challenges were aligned with future scenarios of the evolving generation resource mix and load growth documented in MISO's Future Report and all scenarios pointed towards significant changes in electricity generation and consumption that MISO must prepare for. The objectives of the 2020 LRTP initiative were to prepare for these changes with an overarching goal of ensuring continued grid reliability and cost-effective transmission investments. Moreover, the LRTP initiative developed a framework to categorize the economic benefit types of proposed transmission projects and quantify the specific metrics and subsequent comparison of the quantified benefit relative to estimated cost [49]. Table 2.1 contains the MISO LRTP benefit categories pulled from Section 4 of *MISO's MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Executive Summary*. In July 2022, the LRTP initiative's efforts culminated in MISO's board approving $10.3 billion of 18 new transmission projects in Tranche 1. Three additional portfolios of projects are planned to follow Tranche 1 in the near-term future [46].

LRTP Benefit Category	**Description**
Congestion and fuel savings	Enabling more low-cost renewables to be integrated, which will replace higher-cost resources and lower the overall production cost to serve load.
Avoided local resource capital costs	Enabling renewable resource buildout to be optimized in areas where they can be more productive compared to a wholly local resource build out.
Avoided future transmission investment	Reduction of loading on other transmission lines, in some cases preventing lines from becoming overloaded in the future and thus avoiding the need to upgrade those lines.
Reduced resource adequacy requirement	LRTP projects will expand transfer capability, which will in certain situations increase the ability for a utility to use a new or existing resource from another part of the MISO region, rather than construct one locally, to meet its resource adequacy obligation.
Avoided risk of load shed	Increase of the resilience of the grid and lower the probability that a major service interruption occurs.
Decarbonization	Higher penetration of renewable resources that the LRTP portfolio will enable will result in less CO2 emissions.

Table 2.1: MISO LRTP Benefit Categories

2.1.2 ESIG Multi-Value Transmission Planning

ESIG is a nonprofit focused on guiding the evolution of the grid and energy system integration. It acts as a key resource for the engineering community by offering education, information, and opportunities for networking, aimed at enhancing the integration and operation of comprehensive energy systems [32]. In June of 2022, ESIG's Transmission Benefits Valuation Task Force published a report on a framework for evaluating multi-value benefits for transmission planning, aptly named *Multi-Value Transmission Planning for a Clean Energy Future*. The task force anchors its benefits framework to six multi-value benefits categories that align with the objective of enabling the development of transmission that is economical to customers, reliability improving for the bulk electricity system, and advantageous for accessing and interconnecting renewable energy resources.

Similar to MISO's multi-value transmission planning approach, a cited driving force for the promotion of ESIG multi-value framework is a methodology to economically plan the transmission needed for grid decarbonization. Furthermore, there is an acknowledgment of the multi-value project approach precedent established by MISO's LRTP and a multi-value benefit guideline proposed by Pfeifenberger et al. from the energy consulting and advocacy firm The Brattle Group. The ESIG multi-value framework's alignment with these earlier approaches and guidelines is significant. This is expected since the ESIG report was a collective effort of a task force representative of transmission planning stakeholders from Regional Transmission Organizations/Independent System Operators (RTO/ISO) (an RTO essentially serves the same electricity grid and market operation function as an ISO) planning authorities (including MISO), independent transmission developers (including NextEra Energy Transmission (NEET)), and energy and power system consulting firms. In addition, the MISO LRTP and ESIG benefit categories align with the aforementioned Needs Study Report's main determinants of the need for transmission: a more reliable and resilient grid, easing congestion, connecting new power generation sources, and managing increased electricity demand. A more reliable and resilient grid correlates to resilience benefits, easing congestion correlates to production cost benefits, connecting new power generation sources correlates to generator capital cost benefits, and managing increased electricity demand correlates to resource adequacy benefits. Importantly, this broad alignment is a positive sign that there is consensus on the need for pro-active, multi-value transmission planning, and general agreement on the methodology to evaluate the benefits. For this reason, the ESIG multi-value framework will be referenced and utilized as the standard for multi-value transmission planning for this paper. The benefit categories identified by the ESIG task force are included in Table 2.2 [33].

ESIG Benefit Category	**Description**
Production cost benefits	Quantification of fuel cost savings, reduced curtailment, variable operations and maintenance costs, reduced cycling of thermal power plants.
Emissions reduction benefit	The reduction in emissions of environmental pollutants, including CO2, NOx, SOx.
Generator capital cost benefits	Reduced capital costs of new generating capacity and lower costs of achieving a renewable energy target from being able to access lower-cost renewable regions that are associated with better resource quality, lower land cost, and easier development.
Risk mitigation benefits	Production cost savings across a range of uncertain future conditions associated with varying gas prices, load growth, renewable build-out and thermal plant retirements.
Resource adequacy benefits	The reduction in loss-of-load expectation attributed to the transmission line, compared to the net cost of a new combustion turbine(s) necessary to achieve the same level of reliability.
Resilience benefits	The reduction in unserved energy attributed to the transmission line during the loss-of-load events remaining after resource adequacy improvements, valued at the ERCOT loss-of-load assumption of $20,000/MWh.

Table 2.2: ESIG Benefit Categories

Notably, an important emphasis of the ESIG multi-value transmission planning report is on applying the framework to planning interregional transmission projects. MISO demonstrated successful multi-value transmission planning with LRTP Tranche 1, and a few other RTO/ISOs have taken on similar multi-value planning efforts. However, these efforts have been limited to intra-regional RTO/ISO transmission projects. According to the ESIG report, there is no precedent for applying the framework to interregional transmission projects that span multiple RTO/ISO and planning regions. The report critically demonstrates that the framework proposed can be applied to both long-range interregional and interregional projects. Moreover, a methodology is presented to quantify the key benefit classes for example interregional transmission project that connects Electric Reliability Council of Texas (ERCOT) to the Southern Company's transmission planning region in the southeastern part of the U.S. (includes large parts of Mississippi, Alabama, and Georgia). The subsequent analysis shows that this transmission project is economically viable with a benefit-to-cost ratio of 1.66 [34].

2.2 Transmission Investments

Large-scale transmission investments come in two main types: regulated rate-of-return and merchant investments. Regulated rate-of-return projects are typically overseen by regional and local transmission planning organizations, with costs and a guaranteed return on investment determined through regulatory processes, ensuring stability and risk mitigation for investors. Merchant investments, on the other hand, are financed and constructed without regulatory-led planning processes or regulated rate-of-return, relying instead on market forces and contracts to recover costs and generate profit. This model allows for greater flexibility and responsiveness to market demands but carries higher financial risk.

2.2.1 Regulated Rate-of-Return Investments

Transmission investment follows after transmission planning is conducted by transmission owners and regional planning organizations such as RTO/ISOs. The vast majority of transmission owners that directly invest in and develop transmission are regulated transmission companies. Regulated transmission companies are generally electric utility companies that receive a regulated rate-of-return of their capital investments in transmission infrastructure, which is subject to approval on the federal level by the Federal Energy Regulatory Commission (FERC) and state level by some form of a public utility commission.

Regulated transmission companies are compensated by a standard rate-of-return that is a percentage of the capital investment in addition to recurring operating and maintenance, costs, fees, and taxes. The total project compensation that a regulated transmission collects is referred to as the revenue requirement. Interestingly, a project's revenue requirement does not necessarily reflect its economic value. In other words, the regulated transmission companies are not directly compensated for the value created by a transmission project, but rather the cost. This initially seems unconventional, but practically this makes sense when considering FERC's objective to provide transmission customers with economically efficient energy services. A regulated rate-of-return in conjunction with a multi-value approach for transmission planning provides the regulated transmission company an ensured positive return and favorable benefit-to-cost transmission services to customers at a controlled price.

FERC institutes regulatory processes and orders that govern the transmission planning process and subsequent investments. However, in most cases, FERC's transmission planning regulation only promotes local and regional planning. Generally, interregional transmission planning is not required under these rules. As a result, interregional transmission investments often do not occur despite the near consensus of the need for increased interregional transmission capacity emanating from power sector professionals and emphasized in the Transmission Needs Study report.

2.2.2 Independent Transmission Developers and Merchant Investments

However, there exists a transmission planning and investment model that occurs outside of the process conducted by regulated transmission companies and RTO/ISOs. This planning and investment model is conducted by independent transmission developers. Naturally, upon the restructuring of the U.S. electric power sector from vertically integrated utilities with ownership over generation, distribution, transmission, and retail supply segments to decentralization of these segments, market competition ensued. Market competition accelerated quickly in the generation and retail supply segments, although to various extents across market regions, supported by the competitive wholesale electricity markets operated by the newly established RTO/ISOs. The transmission segment soon followed suit with stimulation by FERC Order 890 in 2007. As leading energy economist Paul Joskow mentions in his report, *Competition for Electric Transmission Projects in the U.S.: FERC Order 1000*, the enactment of FERC order 890 enabled non-regulated transmission companies to participate in the regional and local transmission planning process that has been historically dominated by regulated transmission companies, i.e. incumbent electrical utilities [38]. Slowly in various pockets of the country, non-incumbent, independent transmission developers began to take part in the local and regional transmission planning process. However, the regional transmission planning process was still dominated by incumbent electrical utilities who held the first priority in project selection and investment. In the transmission development field, this is referred to as the right of first refusal (ROFR) to invest, develop, own, and operate the transmission line. Subsequently, FERC Order 1000 instated in 2011 federally struck down the ROFR for transmission development identified in regional transmission plans in favor of independent transmission developers; however, states still held the right to instate ROFR laws at their discretion. Furthermore, FERC Order 1000 has permitted the consideration of public policy needs of transmission and stimulated the use of a competitive bidding process conducted by RTO/ISOs and/or state power authorities to award transmission projects to project developers. Both incumbent electrical utilities and non-incumbent transmission developers are permitted to submit transmission project proposals to request for proposals (RFPs). The selected project proposal's developer is awarded the right to develop the project and receive a regulated rate of return.

In regards to interregional transmission planning, FERC Order 1000 also mandated adjacent planning regions to coordinate on interregional transmission planning to evaluate if more cost-effective transmission solutions could be developed to meet a mutual need [11]. Although this was seemingly a step in the right regulatory direction, the interregional transmission planning mandate is somewhat vague and lacks mechanisms to enforce it. The widely-known interregional transmission planning initiatives executed by adjacent planning regions (RTO/ISOs) is PJM and MISO's planning process to reduce congestion, and SPP and MISO's Joint Targeted Interconnection Queue (JTIQ) for reducing delays in interconnecting new generation [52]. Still, empirical evidence of the limited amount of interregional transmission planning initiatives and actual transmission development taken on by RTO/ISOs support the notion that more must be done. Americans for a Clean Energy Grid (ACEG), a non-profit coalition advocating for the expansion, integration, and modernization of the North American high-voltage grid, provides commentary on this topic in their annual Ready-to-go Transmission Projects report for 2023. Zimmerman et al. of ACEG state that due to poorly developed planning frameworks, "...many of the major interregional projects are being planned and developed by independent transmission developers" [56]. Independent transmission developers have taken an unconventional planning and investment approach to addressing the need for large-scale and interregional projects. Rather than following the RTO/ISO and state public policy-driven planning processes, these project plans are generally formulated by transmission developers' internal analysis of opportunities to relieve congestion across regions, provide low-cost and diversified energy to load centers, and provide reliability and resilience benefits. The investment model is broadly referred to as the merchant model, and it encompasses a variety of different cost recovery mechanisms that rely on market-based pricing of capacity and services provided to wholesale energy markets and load-serving entities.

The most explored and historically significant cost recovery mechanisms for merchant transmission are classic merchant (manifested by exercising congestion revenue rights (CRRs) or executing energy arbitrage) and capacity contracts. In the most fundamental sense, the classic merchant model entails the operation of transmission lines in return for payments reflecting differences in locational prices, and it is mediated through the sale of financial transmission rights, CRRs, or the execution of energy arbitrage of simultaneously buying and selling electricity at different transmission interconnected locations. The CRRs manifestation provides the owner the right to receive congestion revenues defined as the difference between the nodal prices between the two nodes [36]. This financial instrument was originally created to provide wholesale electricity market load-serving entities a hedge against congestion-induced differences in locational prices across a transmission path, and it has since been explored as a means to provide transmission owners the ability to monetize the differences in locational prices. Similar in concept but different in execution, the energy arbitrage manifestation of the classic merchant model monetizes the differences in locational marginal prices by buying electrical energy in a location where prices are low and selling in a different location where prices are high for a profit. A physical, point-to-point transmission link between the low-priced location, Point of Receipt (POR), and the higher-priced Point of Delivery (POD) enables the power flow from POR to POD [12]. Both of these manifestations of classic merchant transmission operation are within the bounds of permitted transmission service authorized by FERC's Open Access Transmission Tariff (OATT). It is important to note that the monetization of classic merchant transmission operation depends ex-post of the transmission capacity expansion across the locational price difference, and that the transmission capacity expansion may result in the reduction of the network congestion that created the original price difference [53]. The effect of this is additional risk and uncertainty of cost recovery.

The classic merchant cost-recovery mechanisms rely on differences in time-varying locational prices, whereas the capacity contract cost-recover mechanism involves transmission owners entering contracts with customers to reserve a specified amount of capacity, which is typically specified as firm uninterruptable and point-to-point (identified as firm point-to-point transmission service in FERC OATT [12]), for power delivery to the customer's load. Similar to physical power purchase agreements (PPAs), transmission capacity contracts charge load customers a price per unit of energy ($/MWh) for delivered power across a transmission line over a long-term contracted period, such as 25 years. Furthermore, the transmission capacity contract is typically paired with a generation PPA and provided to the load customer as an energy generation and delivery via transmission contract. The contractually set prices and long-term agreement aspect of capacity contracts eliminate the exposure to wholesale market prices that exists in the classic merchant model, and it is widely viewed by transmission developers and investors as significantly less risky. It is important to note that the capacity contract cost-recovery mechanism is widely considered by many in the power sector as a form of the merchant investment model because it is a private-sector investment in the development and operation of transmission facilities without relying on regulatory rate recovery mechanisms. Therefore, both the energy arbitrage and capacity contract cost recovery models will be referenced as manifestations of merchant transmission investments in this paper.

The appeal of the merchant investment model for independent transmission developers is the free market access to invest and ultimately provide transmission services. Furthermore, the merchant investment model enables the ability to circumvent the localized regional and state transmission planning process to focus on interregional and long-range transmission needs. As the need for transmission planning reform and interregional transmission has grown over the past few years, more merchant transmission projects have been planned, developed, and even received U.S. federal government support. For instance, in October 2023, the DOE announced that it was entering capacity contract negotiations through the Transmission Facilitation Program for three merchant investment, long-range transmission projects. Ultimately, the DOE will commit up to $1.3 billion across the merchant projects and will act as an anchor customer to support further investments in these specific projects [19].

2.3 Interregional and Long-range Project Selection for Merchant Investment Analysis

Five interregional and long-range projects currently being developed by independent transmission developers were selected from the ACEG's *Ready-to-go Transmission Projects* reports of 2021 and 2023 to evaluate for this paper. The five projects are identified as: (1) Plains and Eastern (modified to reflect the original route and to protect NEET's proprietary transmission plans), (2) Grain Belt Express, (3) SOO Green, (4) Southern Spirit, and (5) SunZia [30][56]. Each of the projects met the selection criteria of being merchant investments and being developed to provide value that is reflective of multi-value benefits of interregional and long-range transmission: congestion relief across regions, access to low-cost and diversified renewable energy, and improvements of reliability and resilience. Thus, the projects were deemed suitable for the objective of this paper, which is to use TBET to heuristically evaluate critical components of the comprehensive benefits of proposed transmission projects and assess merchant-based cost recovery viability. These five transmission projects will be referred to as the "projects under study" throughout this paper. The projects under study were highlighted and labeled in figure 2-1, which was adapted from the ACEG's *Transmission Projects Ready-to-go* report's Map of Proposed Projects.

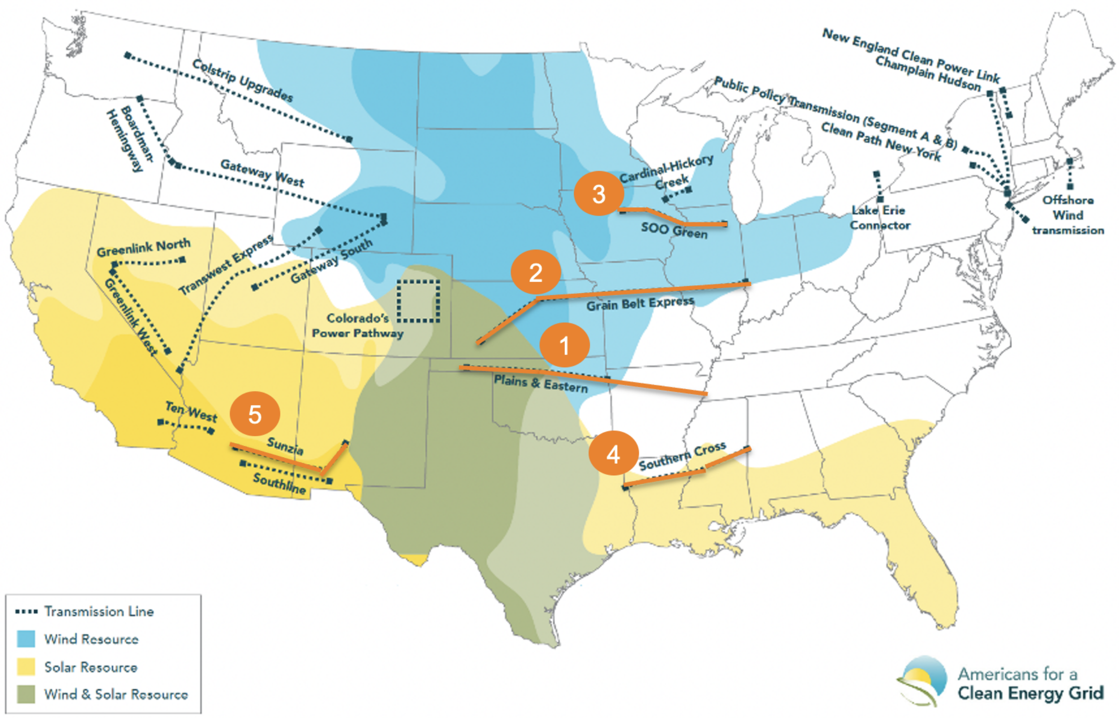

Figure 2-1: ACEG Ready-to-go Projects Map

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Chapter 3

Interregional Transmission Business Evaluation Methodology

3.1 Overview of Transmission Business Evaluation Methodology

Transmission multi-value benefits evaluation is integral for planning economic transmission projects that lower the cost of delivered energy for customers. Therefore, research focus was aimed towards aligning transmission merchant investments with a multi-value planning approach to support a favorable benefit-to-cost ratio for transmission customers. In addition, research focus was aimed towards methodologies to yield viable cost-recovery of merchant transmission investments without the bolstering of a regulated rate-of-return provided by regional and state transmission planning authorities.

As alluded to, transmission multi-value benefits evaluation and cost-recovery analysis are largely quantitative. TBET conducts the analysis based on datasets of transmission project specifications, transmission costs, wholesale electricity prices, renewable energy generation specifications, and renewable energy generation regional levelized cost of energy (LCOE). TBET is a data-processing software program that is informed by cost-recovery logic programmed in Python, and yields project valuation results that represent transmission benefits and the NPV of the projects under study. However, the research that informed the cost recovery mechanisms' formation and utilization of datasets entailed a significant number of qualitative analysis methods. Specifically, the energy arbitrage model's representation of wholesale electricity markets and transmission operation and the capacity contract model's energy offtake agreement logic were informed by concepts and frameworks collected while conducting graduate research at NEET. These concepts and frameworks will be expanded upon in the following sections.

3.2 Transmission Business Evaluation Data Collection

The data classes utilized by TBET and associated analysis tools are the transmission project specifications, transmission costs, wholesale electricity prices, renewable energy generation specifications, and renewable energy generation regional LCOE.

3.2.1 Transmission Project Specification Data

The five transmission projects under study were aggregated from ACEG Ready-to-go Transmission Project reports. Each of the projects selected has qualitative transmission project qualities that align with the objectives of this analysis. These qualities are: merchant investment, interregional and/or long-range, and an intention to deliver diverse, renewable energy to the grid or a load-serving entity. Therefore, they stand to demonstrate multi-value benefits for transmission customers as well as positive business value for an independent developer. The specifications of each of the projects under study provide the geographic location of connection nodes, line length, voltage rating, and current flow technology. These specifications are adjusted in accordance with various modeling constraints that will be expanded upon further in subsequent sections.

3.2.2 Transmission Cost Data

Exploratory cost estimates for the construction and installation of transmission infrastructure are provided by MISO's *Transmission Cost Estimation Guide for MTEP 2023*. This guide provides state and technology-specific cost estimates for proposed projects with low levels of scope definition to provide the ability to quickly assess the cost of various proposed project ideas [51]. These estimates are in cost per mile and are suitable for straightforward, linear approximations for estimating the cost of the proposed transmission projects. This methodology is extrapolated and applied to states outside of MISO's jurisdiction and aided by the methodology introduced by the Eastern Interconnect Planning Collaborative's *Interregional Transmission Development Analysis* report [9]. The transmission projects under study are developed and designed to the extent that there are nearly certain routes or corridors that the projects will be sited across. As a result, there is enough information publicly available to utilize the cost estimation guide's cost per mile to estimate the transmission cost of each project. This information is tabulated in a manner that enables the TBET to import the estimated cost per mile by state, process the data, and compute the estimated transmission project cost.

3.2.3 Wholesale Electricity Price Data

The historically observed wholesale electricity prices utilized by TBET are publicly available prices that are generated by competitive market methodologies coordinated by the RTO/ISO electricity market operator. Notably, there are traditional wholesale market regions that exist outside of RTO/ISO regions; this includes the Southeast and Western regions (apart from California) of the U.S. Traditional wholesale market structures and operations are typically coordinated by vertically integrated utilities that conduct electricity transactions through bilateral trade agreements between electricity generation and load serving entities. Furthermore, traditional wholesale electricity markets are distinctly different from the RTO/ISO competitive market operations as the electricity prices are not necessarily representative of a publicly available price for electricity, but rather a long or short-term agreed upon price between generation and load-serving entities [10]. In comparison, RTO/ISO wholesale electricity prices are locationally specific prices that follow a standard composition structure manifested in the form of Locational Marginal Price (LMP). The specific components of an LMP are: energy component, the cost of an additional increment of electricity generation (MWh) based on supply and demand; congestion component, the cost of dispatching energy in consideration of transmission capacity induced congestion; and loss component, the cost of physical energy losses during energy dispatch [23]. Due to the standardized and publicly available nature of RTO/ISO LMPs, they are the only historically observed wholesale electricity prices that will be utilized by TBET for energy arbitrage analysis. The historical electricity prices are aggregated, organized, and structured for ease of data analysis by the subscription-based services of the power marketing and analysis provider, YESEnergy.

The future forecast of electricity prices is provided by National Renewable Energy Laboratory (NREL)'s Cambium dataset [26]. Cambium's forecast of electricity prices is modeled after the RTO/ISO wholesale electricity price composition structure. Similar to the YESEnergy structured LMP dataset, the Cambium forecasted electricity prices are aggregated as a structured dataset aligned by standardized time-series fields [27]. The structured electricity prices are imported and processed by TBET.

3.2.4 Renewable Energy Generation Specifications

Renewable energy generation facility specifications are used to model the renewable energy that the projects under study will connect to load-serving entities, offtakers. The renewable energy generation is characterized by hourly energy output and levelized cost of energy (LCOE). The specifications of the generation facility include: renewable energy resources, location of the facility, infrastructure technology, nameplate capacity, and other default values configured by NREL's System Advisory Model (SAM) toolset. The input specifications of the generation facility determine the LCOE of the renewable energy resources.

3.2.5 Renewable Energy Generation Regional LCOE Data

U.S. county-specific LCOEs for renewable energy resources data sources provide insight into the differences in the cost of generating energy based on location and generation resource. The LCOEs can be calculated for each county of interest by manually inputting the pertinent data SAM. However, NREL's State and Local Planning for Energy (SLOPE) dataset has already done this calculation and provides the values for all counties across the U.S. [41]. Therefore, the county LCOE values for the projects under study are utilized to determine the renewable energy resources to include in the capacity contract analysis.

3.3 Transmission Business Evaluation Modeling and Analysis Methodology

TBET is segmented into three modules that align with the transmission cost-recovery mechanisms explored and the objectives of the overarching merchant investment analysis. The modules are aptly named: Energy Arbitrage, Capacity Contract, and Net Present Value. The modeling and data analysis for the Energy Arbitrage and Capacity Contract modules are mostly self-contained, and the Net Present Value module supports these other two modules for project valuation calculations. A visual representation of the TBET modules and their respective data inputs is provided in Figure 3-1.

3.3.1 Energy Arbitrage Modeling

The main objective of the energy arbitrage module is to devise and simulate the operation of the market activity of energy arbitrage via transmission in the historical representation and future forecast of wholesale electricity markets. In the most fundamental sense, energy arbitrage in a wholesale electricity market involves buying electrical energy in a location where prices are low and selling it at a location where prices are high for a profit. A physical, point-to-point transmission link between the

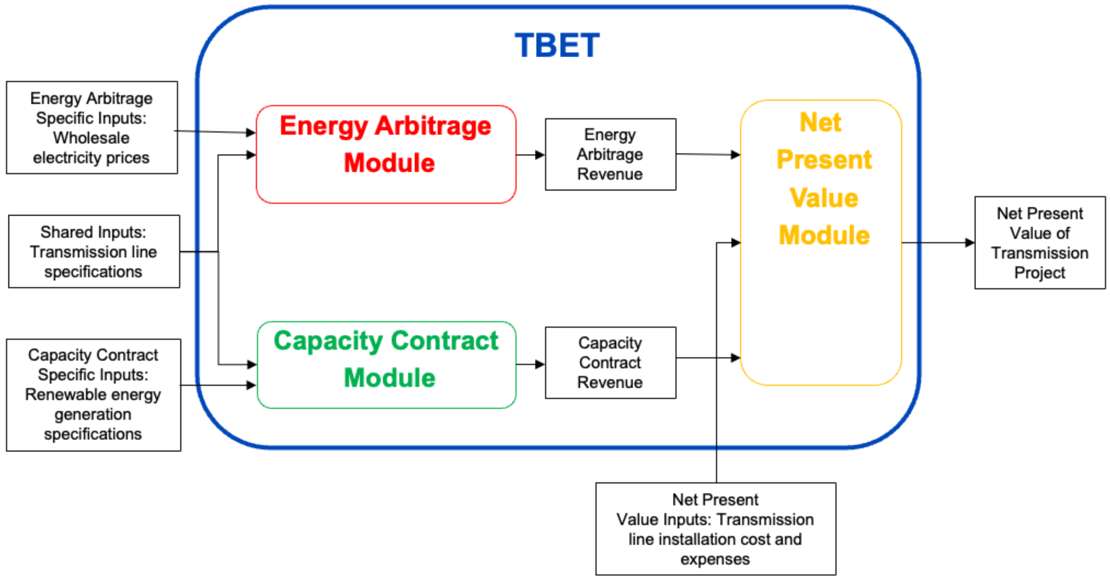

Figure 3-1: TBET Modules and Inputs Diagram

low-priced location, point of receipt (POR), and the high-priced point of delivery (POD) enables the power flow from POR to POD. The differences in nodal LMPs across a transmission connection in theory quantify the differences in the incremental cost of energy and the congestion caused by constraints. With this in mind, it can be deduced that evaluating proposed transmission projects with the energy arbitrage cost-recovery model enables the heuristic evaluation of production cost savings by energy generation cost and congestion reduction while also quantifying the transmission owners' revenue stream captured by conducting the arbitrage.

The analysis of energy arbitrage of historical LMPs quantifies the hypothetical revenue gained if the transmission line was in commission during the historical range of years the LMPs account for. The purpose of this analysis is to provide insight into the value yielded from historical real-world market volatility, mainly inclement weather conditions. The simulation of future LMPs enables forward-looking analysis that provides insight into how a transforming grid will impact financial returns over the lifespan of the projects under study. In this sense, future energy arbitrage analysis follows an ex-ante approach to evaluating the project's financial outcomes. Conducting historical and future energy arbitrage analysis in parallel yields complementary findings that account for both present-day, real-world conditions and probable scenario-based outcomes for the future.

Energy Arbitrage Price-taker Modeling Approach

The computation-reduction requirements of the energy arbitrage analysis were a major factor in the module's development. Importance was placed on the ability to quickly conduct exploratory analysis of multiple transmission projects and specifications. Therefore, it was decided to utilize the price-taker modeling approach with market simplifications that enable computational resource reduction rather than the Production Cost Model (PCM) approach that aims to accurately capture power flow and market operation details. More specifically, the price-taker modeling approach assumes that the power flow operations of the transmission line under study will negligibly affect the electricity LMPs and power flow operations of the larger interconnected grid. This approach is referred to as a price-taker because the modeled transmission operation accepts the prevailing market prices as given and makes decisions such as arbitrage amount, investment, or trading strategies based on those prices. The computation requirement saving is realized because price-taker model assumptions eliminate the need to run the time and resource-expensive computational processing needed to compute system impacts.

As mentioned, the PCM approach to energy system analysis entails accurately representing the underlying electrical physics that governs power flow across the transmission lines and the supply and demand economics optimization that yields LMPs. Within any real-world electrical transmission grid, the grid operator entity such as an RTO/ISO entity will collect supply bids for energy generation and demand bids for consumption and then run a cost minimization optimization model with consideration of grid constraints to obtain total energy generation, consumption, and LMPs at each node in the system. This process is referred to as Security Constrained Economic Dispatch (SCED) [13]. Subsequently, the grid operator will run a power flow analysis with the given SCED results of generation and load at each node to determine the flow of power across the transmission lines and the auxiliary grid infrastructure of substations and converter stations. Importantly, the power flow analysis results will determine power generation constraints and transfer limits to set in the next iteration of SCED. This SCED and power flow analysis process is repeated iteratively until the system converges to a power flow and SCED output that abides by all of the constraints. The entire process is referred to as optimal power flow (OPF) analysis, and PCMs conduct OPF analysis by giving users the ability to simulate this process. By simulating the OPF process for a modeled system resource, the user can evaluate the market performance of system resources. Furthermore, PCMs provide users the ability to account for the energy system impact caused by the behavior of modeled system resources. The impact that resource deployment has on LMPs and electrical power flow is of particular interest to resource owners seeking to optimize their profits. Although PCMs model actual market operations, they are computationally expensive and time-consuming. This tradeoff between modeling speed and accuracy is common in the energy system modeling and analysis field, and the work conducted by Janna Martinek et al. explores suitable conditions to make such a tradeoff without sacrificing too much error in the analysis results [43].

Representation of Wholesale Electricity Market Operations

The energy arbitrage module models the standard two-stage RTO/ISO energy dispatch process. The first stage is the day-ahead energy market that enables the bidding of generation and load resources to produce and consume energy one day ahead of actual operation. The RTO/ISO then runs SCED, to match generation supply to load demand and settle the day-ahead market for each hour of the operating day in each localized load node in the RTO/ISO's region. Due to future uncertainty of actual electricity supply and demand, the second stage referred to as the real-time energy market, is needed to account for the differences in the day-ahead market's committed supply and demand and the actual real-time requirements. The real-time market is settled sequentially in 5-minute intervals, and the electricity prices are far more volatile due to market responses to actual grid conditions that affect energy generation and consumption such as weather and electricity system contingencies.

Real-time market responses and price volatility provide compelling opportunities to conduct energy arbitrage when prices are forecasted to be favorable for revenue generation. However, the revenue reward is matched in proportion to the risk of unfavorable price swings that would lead to economic losses. Furthermore, typically only 5% of energy demand is settled in the real-time market [10]; thus, these prices are more susceptible to energy arbitrage induced price movements that would violate the price-taker modeling assumptions. In contrast, the day-ahead market is often viewed as a viable way for market participants to hedge against real-time price volatility. Therefore, conducting energy arbitrage in the day-ahead market can be more suitable for the price-taker model of energy arbitrage.

The day-ahead and real-time markets have characteristics that make them interesting for energy arbitrage analysis. For this reason, both markets are used in the energy arbitrage module, however, the modeled markets' operations are modified for practical considerations. For instance, it is infeasible to consistently align an electricity purchase in the POR and a subsequent sell in the POD on shorter than a 1-hour interval. Therefore, the market activity modeled in the TBET is configured to exercise arbitrage activity on an hourly basis for both markets. In addition, LMP nodes, the smallest location aggregation for LMPs, provide location-specific prices with high spatial resolution but are too precise for the type of exploratory analysis that the energy arbitrage module conducts. To avoid false precision in analysis results, it was deemed more suitable to use LMP hubs that are composed of LMP value averaged aggregation of multiple nodes.

Energy Arbitrage Actions and Market Forecasting

For the modeled point-to-point transmission projects under study, it is advantageous to have the capability for bi-directional power flow to enable the arbitrage of energy in either direction. This capability of flexible power direction control is standard for high-voltage direct current (HVDC) transmission technology equipped with a voltage source converter (VSC) station. Similarly, high-voltage alternating-current (HVAC) can be equipped with variable-frequency transformer (VFT) technology to enable bi-directional power flow. Therefore, bi-directional power flow capabilities are modeled for all transmission projects under study. Figure 3-2 provides a visual representation of the bi-directional, power flow options for energy arbitrage. In addition, to flowing power in either direction, the model also provides a third option to not conduct any market activity and not flow power across the transmission connection. In this case, no revenue is generated or loss.

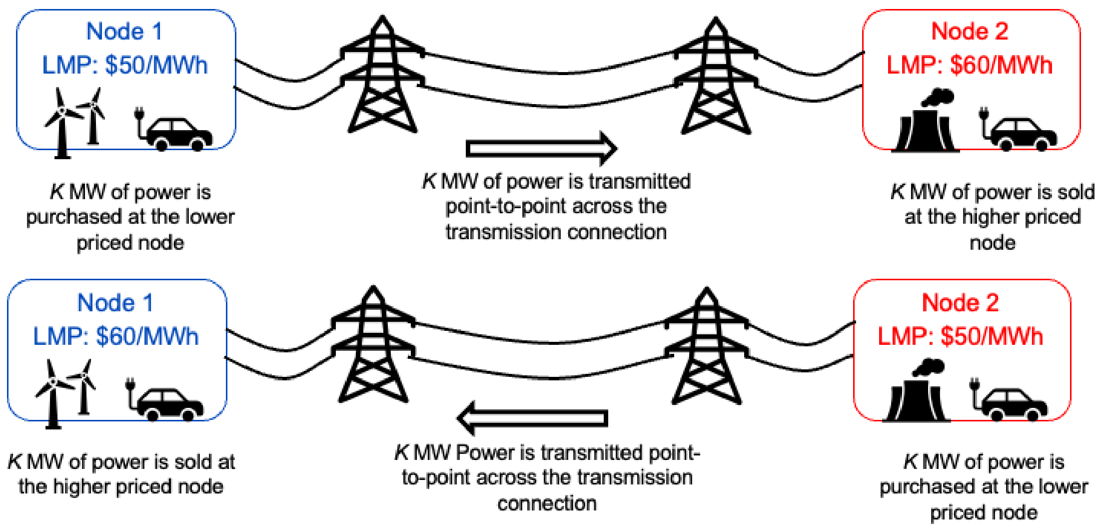

Figure 3-2: Bi-directional Power Flow Options for Energy Arbitrage

The energy arbitrage module models a market participant's day-ahead and real-time predictions of LMPs on an hourly basis and then determines the best option for power flow across the transmission connections based on this prediction. The predictions scheme is designed to provide a range of performance results to be informative of the optimal and worse-case scenarios of resulting financial returns, and revenue streams, rather than being accurate to actual forecasting schemes used by market participants. This range encapsulation scheme is computationally fast, and it does not attempt to add unnecessary practical considerations for an analysis that is intended to produce indicative results. The obvious data inputs for market participant action are the LMPs for the hubs of the transmission project under study. Along with hub LMPs, the per energy unit (MWh) cost imposed on market participants by the RTO/ISOs for exporting energy to another RTO/ISO, referred to as the hurdle rate, and a metric to account for inherent risk and uncertainty in market value, referred to as friction, are accounted for in the modeled power flow option selection.

Transmission Line Specification and Cost Estimation Model

The actual transmission specifications and cost estimate for the projects under study are provided by the ACEG's *Transmission Projects Ready-to-go* 2021 and 2023 updated reports, which summarizes the critical specifications of transmission mileage, voltage rating, and power rating in Table 1 of the respective reports [30][56]. Although this information provides helpful information for guiding the transmission line modeling, the actual projects' specifications are not compatible with the price-taker energy arbitrage model assumptions. More specifically, the actual transmission line specifications for the projects under study are all configured to carry large amounts of power that would likely make a significant impact on the tangential transmission nodes. An estimate of the causal relationship of transmission power flow capacity and the resulting impact on tangential transmission nodes was made by referencing current developments of networked interregional transmission lines such as the Joint Targeted Interconnection Queue (JTIQ) (also included in the *Transmission Projects Ready-to-go* report). The JTIQ project includes multiple transmission lines, and each transmission line is designed to be connected to the larger electricity grid and increase interregional transfer capacity [52]. Therefore, it is assumed that each individual JTIQ transmission line is designed to have a power flow capacity sufficiently large enough to affect tangential transmission nodes' power flow and LMPs. Deductively, the power flow capacity of an individual JTIQ transmission line, which is 1792 MW, exceeds the absolute upper limit of acceptable power flow capacity that will abide by price-taker modeling assumptions. As a result, it was determined that the price-taker energy arbitrage line capacity should be well below an individual JTIQ transmission line power flow capacity.

The cost estimations of the transmission lines were adjusted according to the modified transmission line specifications. The cost estimation serves as an exploratory evaluation of the potential costs associated with the development, construction, and operation of the transmission project under study. This type of analysis is crucial in the early stages of project planning and decision-making. The transmission cost analysis is largely based on the 2022 MISO Cost Estimation Guide exploratory cost estimates. Although the projects under study are beyond the early stages of project development and have more defined scopes in actuality, they are being significantly redefined in scope and redesigned along multiple transmission specifications. Therefore, the exploratory cost guide is suitable for the model's representation of the projects under study.

A few additional notable modifications to the transmission specifications of the projects under study are important to acknowledge. First, all projects were modeled as standard overhead lines to align with available data in standard transmission cost estimations guides. Undersea and underground transmission lines have historically been more expensive to develop, and although SOO Green is currently planned as an underground line, the driving factor for this design plan was for faster land permitting rather than significantly different transmission operation [31]. Therefore, modeling the transmission project as an overhead line will mainly just reduce the installation capital cost, and it is noted accordingly. Secondly, the energy arbitrage module can evaluate both High-voltage Direct Current (HVDC) and the traditional High-voltage Alternating Current (HVAC) current flow technology for transmission, and both options will be explored.

Modeling Assumptions and Reasoning

Along with the price-taker modeling approach, additional model assumptions and resulting simplifications were employed for the energy arbitrage module for noteworthy reasons. The first reason is to supplement the model's ability to be computationally fast and flexible. The supporting assumptions for the first reason include: the power flow across the transmission line required to physically deliver the energy arbitraged is feasible regardless of the state of the bulk electricity system, the supply of energy at the POR and the demand of energy at the POD is constant for the hourly time-period modeled in the real-time, wholesale electricity market. The second reason is that there are complicated grid operator decisions and economic strategies at play in energy systems and markets that are inherently difficult to model. Hence, they require assumptions to estimate probable behavior and mechanism outcomes. The supporting assumptions for the second reason include: a simplified market price forecast strategy, arbitrage market participants can perfectly align market bidding schedules to purchase energy in one RTO/ISO and sell in another RTO/ISO in the standard real-time and day-ahead electricity markets, and the transmission resource operation will not be subject to constrained utilization due to exogenous factors such as inclement weather or concerns of grid reliability and resilience at the discretion of RTO/ISO grid operation.

Additional quantitative, metric-based model assumptions and the resulting limitations are included in Table 3.1. As with any model, there is an inexhaustible list of real-world details that are not represented entirely. The belief is that the main functionality of market-based energy arbitrage is represented to the extent that the results of the analysis are useful for the module's intended purpose.

3.3.2 Energy Arbitrage Analysis

The energy arbitrage analysis for the projects under study is conducted in the following steps: (1) transmission line specification, (2) historical and future energy arbitrage, and (3) NPV calculation of energy arbitrage value.

Transmission Line Specification Analysis

Similar to the approach of modifying the design proposal of the SOO Green project from underground to overhead transmission pathway and considering AC current-flow technology options for cost-efficiency considerations and modeling cohesion, the same principle is applied to the voltage rating and power transfer capacity for each project. The line length specification will remain unchanged from the design proposals to preserve the transmission route and hub regions that are arbitraged across, and the current-flow technology selection will consider both HVDC and AC technology types.

HVDC technology provides power flow efficiency improvements when compared to

Arbitrage Metric	Model Assumption	Reasoning
Hurdle rate	Standard hurdle rate of \$5/MWh	The charge for transferring energy point-to-point is negotiated by neighboring RTO/ISOs and can change based on the transmission route, time of transfer, and other factors [45].
Market price uncertainty friction	Standard friction of \$5/MWh	Market price uncertainty metric serves as a buffer to safeguard against making decisions based on small LMP swings. Although it could be adjusted in proportion to the volatility of the market, it is more suitable to set a standard rate for analysis parity across markets.
Transmission line power rating and transfer efficiency	Constant values that are calculated based on only physical transmission line specifications	Line ratings can be adjusted dynamically based on environmental conditions but require pertinent data and processing that is beyond the scope of this model.

Table 3.1: Energy Arbitrage Modeling Assumptions

the AC alternative. This is driven by lower electrical resistance per line length and the absence of reactive line components that give rise to cyclical energy flow to and from reactive components in AC transmission. However, power transmitted on HVDC transmission lines needs to be converted to alternating current to interconnect with the bulk electricity system. This requirement is also true for interconnection to the POR and POD for the energy arbitrage modeled transmission line; thus, this requires a separate converter station for the generation and load region. MISO estimates the cost of voltage source converter stations (VSCs) as over \$400 million per 400 kV converter station, which can be a sizeable fraction of the entire transmission line cost. As a result of the necessary cost components and power flow efficiency, cost considerations favor HVDC for long-distance transmission lines and AC for shorter distances. More comprehensively, the cost-effectiveness of one current-flow technology over another comes down to the cost of delivering a specified amount of power over a specified distance. The cost break-even distance for HVDC and HVAC will vary depending on the other transmission line specifications such as power rating, but it is generally cited as at a distance of 300-400 miles [14].

Another technical factor that influences the decision to select HVDC or AC current flow technology is the physical transmission connection made by the project under study. The Southern Spirit projects connect the asynchronous Texas and Eastern Interconnection grids. DC current flow technology is the most widely use method to connect asynchronous grids, and it is the only choice explored for this project in the energy arbitrage module.

The voltage class and power transfer capacity line specifications are configured in accordance with the constraint set to limit the power flow capacity of the projects under study to the power rating of the JTIQ transmission project (1792 MVA). The highest capacity transmission voltage classes for HVDC and AC that adhere to this constraint were chosen. These voltage classes are HVDC 400 kV and AC 345 kV (double-circuit configuration). Generally, higher capacity transmission lines are considered more cost-effective primarily due to economies of scale and improved efficiency in transmitting electricity over long distances.

From the transmission line's electrical conductor properties, voltage class, length, and power loading, the power transfer efficiency of the line can be estimated. For HVDC current flow technology, the transmission line's conductor resistance and DC current are the drivers of resistive power dissipation that make up most of the total system losses. The resistive power dissipation along the length of the HVDC line grows linearly with resistance, R_{dc} and quadratically with DC current, I_{dc} as described by 3.2. The HVDC transmission line's I_{dc} is controlled by the power electronics in the converter station to maintain system stability and desired power flow conditions, whereas $\mathrm{R_{dc}}$ cannot be adjusted during operation and is determined by conductor parameters, temperature, and length. Glover et al., provide a useful formula and associated resistivity constants for analyzing the conductor resistance at a specified temperature in 3.1 [28]. The cross-sectional area of the conductor, A, has a standard value for the common conductor type of aluminum copper steer reinforced (ACSR), and the resistivity ρ_{T} can be calculated for a typical operating temperature such as 100°C [1]. In contrast, the conductor line length l can vary significantly based on a designed transmission route, the number of conductors and circuits used, etc. For this reason, often the efficiency estimates of HVDC lines are given in percentage per distance. Estimating actual values for R_{dc} and I_{dc} is usually done by integrated functions within power system simulation software and is beyond the scope of this analysis. Therefore, average values sourced from the U.S. Energy Information Administration's *Assessing HVDC Transmission for Impacts of Non-Dispatchable Generation* report of the transmission line's power transfer efficiency at 1200 MW load of 3.5% per 1000 km, and 0.75% losses at converter stations are used[5].

$$R_dc = \frac{\rho_T l}{A} \tag{3.1}$$

$$P_R = I_dc^2 R_dc \tag{3.2}$$

For HVAC current-flow technology, the resistive power losses are larger per unit length of transmission due to the frequency of sinusoidal current oscillations causing a phenomenon referred to as the skin effect, which effectively reduces the cross-sectional area of the conductor. Glover et al. provide formulas and information for calculating the real power loss of a transmission conductor based on the AC resistance, R_{ac} and root-mean-square (RMS) conductor current I. This formula is provided in 3.3. Again, estimating actual values for these parameters is usually done by power system simulation software and is beyond the scope of this analysis. Therefore, an average value of the transmission line's power transfer efficiency at 1,200 MW load of 6.7% per 1,000 km from the Energy Information Administration's *Assessing HVDC Transmission for Impacts of Non-Dispatchable Generation* report is used [5].

$$P_Loss = |I| R_ac \tag{3.3}$$

The most significant factor that determines HVAC transmission real power flow capacity is the steady-state stability limit (SSL) that ensures that the POR and POD connections of the transmission line will remain synchronized to the AC bulk electricity system, thus, it is critical to account for this. The SSL is a function of transmission line loading relative to intrinsic conductor impedance parameters, referred to as surge impedance loading (SIL), and line length. In Glover et al.'s *Transmission Lines: Steady State Operation* chapter, it is demonstrated that the typical SIL of a transmission line can be modeled as a function of the voltage rating and characteristic impedance of the transmission line. Furthermore, this book's chapter provides a useful table (denoted as *Table 5.2* in the chapter's text) for finding the SIL of a typical 60 Hz, overhead transmission line and a *Transmission-line loadiblity curve* for finding the theoretical SSL in per-unit of SIL based on transmission line length (denoted as *Figure 5.12* in the chapter's text) [29]. The *Transmission-line loadiblity curve* is displayed in Figure 3-3. After identifying the SIL of 325 MW of the 345 kV rated projects under study and referencing the theoretical SSL in the *Transmission-line loadiblity curve* displayed, the final theoretical SSL of the projects under study was calculated.

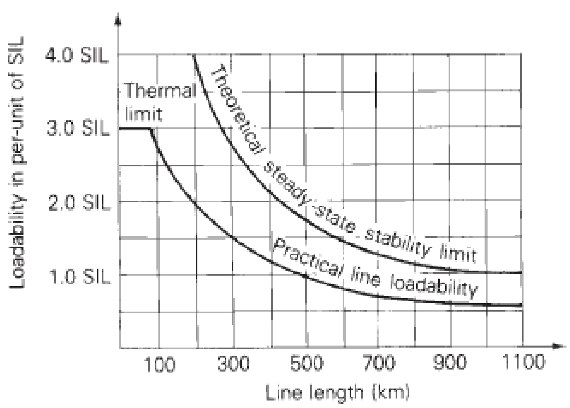

Figure 3-3: *Transmission-line loadiblity curve* from Glover et. al *Transmission Lines: Steady State Operation* chapter

Finally, the DC resistive losses for the HVDC current-flow technology transmission specification and the SSL and AC resistive losses for the HVAC current-flow technology transmission specifications were calculated and configured in a data input table for TBET to import and utilize for energy arbitrage analysis for the projects under study. Table 3.2 summarizes this data input table.

Transmission Line Cost Estimation Analysis

Leveraging the *Transmission Cost Estimation Guide for MTEP 2023* as a calculation guide, the major cost components for the projects under study are estimated according to MISO's state models. Then, the costs for projects outside of MISO's area of coverage are scaled by the appropriate region's multipliers in accordance to the EIPC'S calculated *NEEM Region Multipliers for New Lines values* [9]. Lastly, the cost components are then input into the cost summation function in TBET to reach a total cost.

More specifically, *Transmission Cost Estimation Guide for MTEP 2023* provides the general relationships between implementation cost components and transmission specification parameters in a linear fashion. The implementation costs are inclusive of all costs to implement the transmission project; hence, it includes engineering design and studies, transmission facilities hardware, land acquisition and right-of-way, installation, etc. This all-inclusive implementation cost is extended across a variety of dimensions that account for the costs of standard configurations of voltage classes, circuit configurations, HVDC converter station technology, HVAC substation arrangement, and U.S. states that the project is installed. The linear cost relationship pertinent to the specifications of the projects under study includes the following: transmission line implementation cost per mile and converter station implementation per unit. This allows a total cost estimation to be calculated by quantifying each project's transmission line route length in each state it connects and converter stations for HVDC (2 VSC stations for each project) and substations for HVAC (2 substations for each project). For any available permutation voltage class, circuit configuration, and HVDC/HVAC converter station technology, the linear relations enable quick and flexible calculations that take the form of 3.4 for HVDC and 3.5 for HVAC. In this equation, n represents the number of states connected by the transmission route. This exploratory cost estimation was conducted on the projects under study, and Table 3.3 displays the resulting implementation cost values.

$$HVDCTransmissionCost_{tot}(\$) = \Sigma_{s=1}^{n}(state_s)(length_s)(NEEMmult_s)+2converter \quad (3.4)$$

$$HVACTransmissionCost_{tot}(\$) = \Sigma_{s=1}^{n}(state_s)(length_s)(NEEMmult_s)+2substation \quad (3.5)$$

In addition to the cost incurred for the project while undergoing development and construction accounted for in the implementation cost, *Transmission Cost Estimation Guide for MTEP 2023* also provides an estimate of the re-occurring annual expense of property taxes and operations and maintenance (O&M) based on the U.S. state within MISO's region. For the states outside of MISO's region, this value is scaled by the same factor as the implementation cost. The expense factor is applied and accounted for in the subsequent NPV analysis.

Historical and Future Energy Arbitrage Analysis

Historical energy arbitrage analysis begins with importing and processing the real-time and day-ahead market data for hubs of the projects under study. Additional market information that represents the module's assumptions of hurdle rates of exporting energy from one RTO to another and uncertainty friction of arbitrage viability are also processed and accounted for. After the time-series data of LMPs are aligned for each hour, the energy arbitrage is executed according to the market forecasting methodology. The revenue that is accumulated from the point-to-point energy arbitrage for each project under study over the historic date range is summed and tabulated for each transmission line specification. The revenue accumulated over notable extreme weather event dates where LMPs are significantly higher than average, referenced as tail-events, are tabulated separately from the total revenue stream for separate analysis which will be elaborated on in the results section. Historical energy arbitrage analysis requires access to publicly available RTO/ISO market data. Since the SunZia transmission project spans the non-RTO/ISO West Connection region, it does not have readily available wholesale market data to enable historic energy arbitrage analysis. For this reason, SunZia is omitted from this analysis.

Future energy arbitrage analysis begins with importing the future forecasted marginal electricity prices that are conceptually similar to Day-ahead market LMPs, and are thus treated as such in the analysis. The subsequent steps then align the time-series data of LMPs for each hour and execute energy arbitrage according to the market forecasting methodology. The results of this process yield annual energy arbitrage revenue for each year in the range of future forecasts, each scenario (9 in total), and each project under study. The results are tabulated accordingly.

The historical and future energy arbitrage analysis follows the same general steps and programming logic for energy arbitrage operations. The flowchart in Figure A-1 in Appendix A depicts these steps and programming logic.

NPV of Energy Arbitrage Value Analysis

The revenue streams from the transmission projects' future energy arbitrage analysis across the selected scenarios of the electricity sector are regarded as energy arbitrage value. These values constitute the cash inflows for project valuation NPV analysis. The installation cost, re-occurring annual expenses, and tax expenses are the cash outflows. The cash inflows for each scenario are subtracted by the cash outflows and then discounted by the NPV module specified weighted average cost of capital (WACC) to produce an NPV for each project across each scenario.

Project	**Line Length (miles)**	**Current-flow**	**Conductor Voltage**	**Real Power Transfer Stability Limit (MW)**	**Real Power Flow Efficiency**	**Total Real Power Flow (MW)**
Plains and Eastern	675	HVDC	400 kV	1,000	95%	952
Plains and Eastern	675	HVAC	345 kV (double-circuit)	850	93%	790
Grain Belt Express	790	HVDC	400 kV	1,000	95%	947
Grain Belt Express	790	HVAC	345 kV (double-circuit)	850	92%	780
SOO Green	340	HVDC	400 kV	1,000	97%	969
SOO Green	340	HVAC	345 kV (double-circuit)	1,530	96%	1,476
Southern Spirit	395	HVDC	400 kV	1,000	97%	966
SunZia	550	HVDC	400 kV	1,000	96%	958
SunZia	550	HVAC	345 kV (double-circuit)	1,063	94%	1,002

Table 3.2: Summary of Transmission Projects Under Study Specifications

Project	**Line Length (miles)**	**Current-flow**	**Conductor Voltage**	**Total Implementation Cost ($ Millions)**
Plains and Eastern	675	HVDC	400 kV	$1,959
Plains and Eastern	675	HVAC	345 kV (double-circuit)	$2,447
Grain Belt Express	790	HVDC	400 kV	$1,972
Grain Belt Express	790	HVAC	345 kV (double-circuit)	$2,434
SOO Green	340	HVDC	400 kV	$1,527
SOO Green	340	HVAC	345 kV (double-circuit)	$1,375
Southern Spirit	395	HVDC	400 kV	$1,197
SunZia	550	HVDC	400 kV	$1,549
SunZia	550	HVAC	345 kV (double-circuit)	$1,298

Table 3.3: Implementation Cost of Transmission Projects Under Study

3.3.3 Capacity Contract Modeling

The objective of the TBET capacity-contract module is to utilize the POR's renewable energy generation model and the associated PPA price calculated by the SAM tool in conjunction with the cost estimates of the transmission project under study to produce a total PPA price of the renewable energy and transmission system. The total PPA price is then compared to the PPA price of local alternatives for renewable energy generation modeled at the POD for the transmission projects under study. Logically, a business-viable transmission project will yield a more cost-competitive total PPA than the local alternative renewable energy PPA price, and be attractive to transmission customers for contract offtake. An additional consideration of the comparison between the generation and transmission system to the local alternative for renewable energy generation is the performance of the renewable generation model in adherence to a hypothetical 30% renewable portfolio standard (RPS), which would require at least 30% of electricity generation be sourced from renewable energy. The price differential of the two PPA prices serves as a heuristic estimate of the production cost savings benefit of the project, and the RPS performance of the renewable generation model serves as a heuristic estimate of generation capital cost benefits. Through this comparison process, the capacity contract module also analyzes the cost-recovery viability of the capacity contract.

Capacity Contract Uni-directional (Gen-tie) Modeling Approach

The point-to-point firm transmission designation specified in FERC's OATT enables transmission owners to enter contracts with customers to reserve a specified amount of uninterrupted transmission capacity for energy delivery to the customer's load. This is commonly referred to as a transmission capacity contract. It is also referred to as a Power Purchase Agreements (PPAs) contract due to the pairing and conceptual similarity to power generation and load consumption PPAs that have become standard practice for renewable energy contracted transactions. For renewable energy PPAs, the energy generated is sold to a customer, such as a commercial, industrial, or electrical utility that has contractually agreed to purchase, offtake, the energy at a set price measured in dollars per MWh ($/MWh). The contractual agreement of the physical deliverance of the energy generated to the customer is either omitted and substituted with financial hedge agreements as in the case of virtual PPAs or explicitly defined and supported by existing transmission along with necessary network upgrades informed by interconnection studies. Generally, the contract is structured in a manner in that the generator will pay for the upfront capital cost of paying for needed transmission interconnection and network upgrades for power delivery and then priced-in to the total energy cost to incrementally pass the cost on to the consumer over the length of the contract. The entity that develops the physical transmission interconnection, commonly referred to as a gen-tie, is an incumbent utility or more increasingly independent transmission developer pursuant to FERC order 845 [8]. This has given rise to the idea of independent transmission developers offering capacity contracts to off-takers seeking access to dedicated gen-tie connections to renewable energy generation. The capacity contract states the transmission charge to deliver energy across the line ($/MWh).

The transmission capacity contract framework is most often coupled with renewable generation PPAs provided to the offtaker in a lump-sum amount for generation plus transmission delivery. Notably, this gen-tie configuration is conducive for point-to-point transmission. Similar to the energy arbitrage configured lines, there is no physical restriction that prevents bi-directional power flow on capacity contracted lines. In fact, bi-directional power flow transmission operation has been notably planned by several of the DOE's Transmission Facilitation Program capacity contracts award recipients [19]. However, for the capacity contract analysis conducted by the TBET, only uni-directional flow gen-tie assessments will be conducted for modeling simplification and representation of the primary power flow direction. Figure 3-4 provides a visual representation of the uni-directional, power flow for the capacity contract modeled system.

The single directional flow capacity contract modeled in TBET is a generation plus transmission system that includes: SAM-produced renewable energy generation profiles, proposed transmission line specifications, cost and financing estimations for the total system, and total system PPA price.

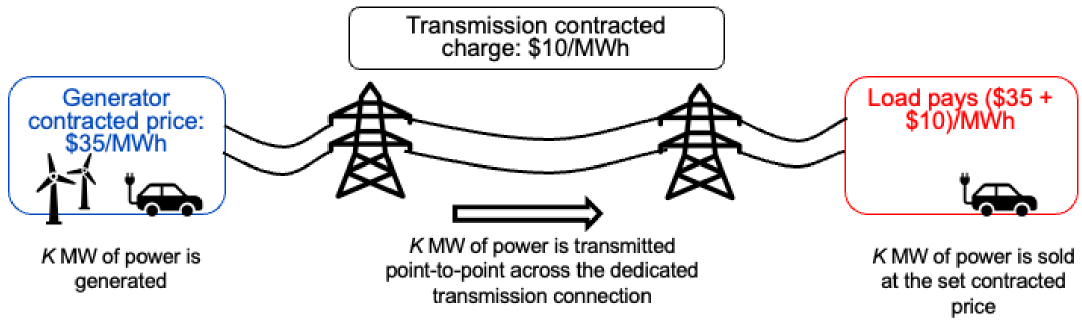

Figure 3-4: Uni-directional Power Flow for Capacity Contract

Representation of Renewable Energy Generation

The generation component of the capacity contract system model accounts for the potential energy generated by high-quality renewables in the generation region and energy storage, which can supply firm capacity to the system. The vast majority of the renewable energy facilities awaiting interconnection to the grid are intermittent or variable renewable energy resources: solar, wind, energy storage, and a combination of the preceding resources commonly referred to as hybrid resources. Once interconnected, all of these resources provide intermittent or variable power to the grid. Quite simply, when the sun is not shining, solar photovoltaic energy facilities do not generate a significant amount of power. The same is true for wind generation facilities when the wind is not blowing. For this reason, these generation resources or referred to as intermittent or variable renewable energy (VRE), and often require co-utilization with different energy generation resources or storage facilities. This co-utilization approach is taken for the projects under study and will be expanded upon further in the subsequent generation profile analysis section.

The optimal renewable energy resource to develop in any particular region primarily depends upon the region-specific capacity factor of the resource. Alongside the "ready-to-go" transmission projects displayed in Figure 2-1, the map also displays the highest capacity factors for wind and solar across the country shaded in blue and yellow respectively. Keeping in mind that the capacity factor metric is the measure of how much energy would be produced by a renewable energy facility in these geographic areas over a period as compared to its maximum rated output, Figure 2-1 demonstrates that the highest potential renewable energy resources are generally in the middle of the country and relatively far from the major load centers that are large cities. Importantly, this figure also demonstrates the opportunity for transmission to deliver the highest capacity factor renewable energy, and thus cheapest, to the load centers. As noted in Section 2.3, this idea is a major factor for the origination of the transmission projects under study. Furthermore, the projects under study are intentionally designed to deliver a diversified renewable energy resource to the load region. In tandem, the combination of low-cost and diversified clean energy directly relates to several transmission multi-value benefits such as production cost savings and generation capital cost reduction. For instance, the Grain Belt Express project is designed to access the rich solar and wind potential in southwest Kansas and deliver to the Indiana region which lacks significant solar potential or existing capacity. According to the Indiana region's major utility, Duke Energy, their plans for future energy generation to meet their internal renewable portfolio standard (RPS) is to develop additional solar plus storage facilities to compliment the existing wind in the near future [35]. However, the capacity factor of a solar facility in Indiana is cost-inferior to the generation that Grain Belt can deliver, and storage may still be prohibitively expensive. To demonstrate this, the SAM toolset is utilized to model the generation in both regions. The renewable energy generation in southwest Kansas plus transmission is compared to the local Indiana alternative for renewable energy generation. This process is generalized and applied to all of the projects under study.

Capacity Contract Transmission Line Specification and Cost Estimation Model

Following the approach of the energy arbitrage module's transmission line specification modeling, the base starting point for the modeling was the ACEG's *Transmission*

Projects Ready-to-go 2021 and 2023 updated reports, and then several transmission specifications are rescaled to fit the capacity contract module's uni-directional modeling approach. Again, all projects will be modeled as standard overhead lines to align with available data in the utilized transmission cost estimations guides. In contrast to the energy arbitrage module, only HVDC current-flow technology will be considered for notable reasons associated with renewable energy generation. HVDC current-flow technology permits the use of VSCs that enable flexible power control and the ability for VRE resources such as solar and wind generation to restart the interconnected grid without the support of traditional synchronous generation. This is referred to as black-start capability and is a desirable functionality for transmission lines that directly connect to VREs [24]. The evidence of this is in the fact that all of the projects under study have actual plans to use HVDC current-flow technology and VSCs [40][31][21][20]. Therefore, HVDC current-flow technology and VSCs will be used in the capacity contract transmission model to preserve the value that this technology provides for renewable energy grid integration. The voltage class and power rating transmission line specifications were modified to be a function of the modeled generation capacity. More specifically, The power rating of the lines was assigned to be equivalent to the modeled generation capacity of the projects under study. Assuming a standard balance of system load and losses for the generation resources, the generation output will never exceed the transmission power transfer capacity and will have the desired effect of nearly maximizing the line utilization when the generation facility is producing at full capacity. The cost estimations for the capacity contract module are adjusted according to modified transmission line specifications and follow the same evaluation methodology as the energy arbitrage module.

Capacity Contract Energy System Financing Model

Financial estimates of the capacity contract system are significantly affected by the discount rate that is used for the analysis. This parameter is a critical input into the generation PPA price calculated by the SAM tool. From the perspective of financing and developing the energy system from an independent power producer (IPP) and transmission developer such as NextEra Energy, the appropriate discount rate to use for this analysis is the independent developer's weighted average cost of capital (WACC). For confidentiality, the WACC of independent developers of renewable energy facilities and transmission is not publicly available. In place of a company-specific WACC, NREL's *Current and Future Costs of Renewable Energy Project Finance Across Technologies* report estimates for the WACC of IPPs for different generation resources are used for the analysis of the proposed projects under study. The pertinent renewable energy generation WACC estimates are provided in *Table ES-1* of this report [25]. Another impactful financial consideration accounted for is the effect of federal clean energy tax credits. The passing of the IRA in 2022 extended and expanded tax credits for the development of renewable energy projects. This includes the Investment Tax Credit (ITC) for installing renewable energy equipment and the Production Tax Credit (PTC) for electricity generated from renewable sources. Renewable energy project developers are eligible to select either the ITC or PTC. The SAM tool is configured to automatically select the cost-optimal option.

Capacity Contract Modeling Assumptions and Reasoning

The capacity contract module makes significant use of the SAM tool's renewable energy generation modeling capability which has notable embedded assumptions. These assumptions are implicit in the data inputs that are sourced for the generation modeling. For instance, SAM accounts for a specified year's worth of hourly resolution of region-specific weather data to calculate annual energy generation. Accounting for just one year of weather data could be viewed as limited for evaluating energy infrastructure that will be in operation for 25 years. However, SAM provides the option to select a "typical year" of weather data that is a better representation of multi-year weather fluctuations. The "typical year" methodology is defined as "The typical year methodology involves analyzing a multi-year data set and choosing a set of 12 months from the multi-year period that best represents typical conditions over the long term period."[42]. Therefore, focus is paid towards providing robustness to the weather data input, so it may not be a major cause for concern. Nevertheless, generation and transmission infrastructure are prone to the effects of other exogenous factors outside of typical weather conditions that could reduce output and capacity over the 25-year life span. Accounting for these stochastic exogenous factors is inherently difficult in ex-ante analysis and possibly infeasible for the intended computational resource-reduced approach.

Apart from the SAM tool's embedded assumptions, it is also important to acknowledge that the assumption of the in-existence of RTO/ISO grid operator instated constrained capacity due to grid reliability and resilience concerns is an over-simplification for capacity contracts; just as it was an over-simplification for the energy arbitrage module. Although the single directional flow gen-tie systems make imposed reliability and resilience constraints less likely due to the gen-tie dedicated transmission connection, the probability of a contingency occurrence is non-zero. Again, due to the difficulty in modeling the non-deterministic probability of the occurrence and severity of such events, the TBET capacity contract module does not account for this.

Another broad assumption modeled across the capacity-contract module is that the large cost components of the modeled renewable energy generation and storage technology prices will remain constant from the present day to the proposed installation date. The installation and operating cost components were set to the default values provided by the SAM tool, which reflect present-day estimates. Based on historical precedent, this is likely not going to be a valid assumption for projects that will begin technology installation even five years from now. In particular, the installation cost of the standard utility-scale, single-axis tracker solar modules has decreased by 16% from 2017 to 2023 and the installation cost of utility-scale, 4-hour lithium-ion battery storage has decreased by over 60% [54]. Although most forecasts project a slower rate of technology cost decrease over the next 5 years, there will still be a significant decrease. The inherent uncertainty of future technology installation cost and project installation dates combine to make the task of coming up with a data-driven projection for future technology installation cost difficult and error-prone. Therefore, the default 2023 technology installation cost is consistently used across the capacity contract model.

3.3.4 Capacity Contract Analysis

The capacity contract analysis for the projects under study is conducted in the following steps: (1) generation profile, (2) transmission Line specification, (3) cost and finance estimation, (4) total PPA price and resulting revenue calculation.

Capacity Contract Generation Profile Analysis

The POR of the projects under study are denoted as the generation regions. Each project's generation region is located in a high capacity factor wind and/or solar geographic areas by the original design of the project, as displayed in Figure 2-1. It seems obvious to simply model the high capacity factor wind and/or solar resources in the generation regions for transmission delivery and capacity contract analysis. However, it is important to consider the cost-effectiveness of the generation resources relative to the generation profile of the POD, denoted as the load region. Based on the established value theory of the single-directional, capacity contract model, a renewable energy generation resource should be developed and delivered via transmission to the load region if it can be generated at a competitive price. For example, it would not be economically feasible to deliver solar energy from a generation to a load region that has a high capacity factor solar potential because it likely would not be of much utility to the load region. There are of course exceptions to this simplified viewpoint of capacity contract energy generation and delivery opportunities such as land constraints in a hypothetical high capacity factor load region that prevents cost-effective renewable energy development, but land constraints are ignored in this analysis due to inaccessible geospatial data. Therefore, the general logic that is followed for this analysis is to model the generation region's high capacity factor wind and/or solar when its LCOE determines it is reasonably cost-effective relative to the load regions's wind and/or solar LCOE. To build a baseline understanding of the cost competitiveness of renewable energy resources, an LCOE comparison was made between the generation region and the load region for the projects under study. The LCOEs were provided by NREL's (SLOPE) platform [41] and are displayed in Table 3.4. From this comparison, it is straightforward to identify the significant LCOE differences across the regions that present opportunities for delivering cost-effective renewable energy with transmission. For each transmission project under study, the wind and solar LCOEs that generate larger or equal to a \$5/MWh difference from generation to load region are selected for further analysis in SAM for the project.

Project	**Generation Region**	**Generation Region - RE Resources LCOE (\$/MWh)**	**Load Region**	**Load Region - RE Resources LCOE (\$/MWh)**
Plains and Eastern	Guymon, OK	Wind - \$30, Solar - \$37	Memphis, TN	Wind - \$44, Solar - \$44
Grain Belt Express	Dodge City, KS	Wind - \$30, Solar - \$38	Terre Haute, IN	Wind - \$39, Solar - \$47
SOO Green	Mason City, IA	Wind - \$32, Solar - \$43	Naperville, IL	Wind - \$39, Solar - \$48
Southern Spirit	Tyler, TX	Wind - \$29, Solar - \$42	Starksville, MS	Wind - \$55, Solar - \$43
SunZia	Torrance, NM	Wind - \$30, Solar - \$34	Florence, AZ	Wind - \$66, Solar - \$37

Table 3.4: Generation and Load Region LCOEs Sourced from SLOPE

As observed in Table 3.4, in some generation region instances there exist cost-competitive solar and wind resources, and the modeling of co-located wind and solar generation is viable. In these cases, both wind and solar resources were modeled, but wind generation capacity is prioritized for several reasons. First and foremost, the standard metric for comparing the economic competitiveness of different energy resources is by calculating their total lifecycle costs divided by energy output, levelized cost of energy (LCOE), which indicates that wind has a lower levelized cost, and is thus the cost-optimal option in accordance to the standard equation of LCOE 3.6. In this equation: I_t is the capital expenditure in year t, M_t is the operations and maintenance expenditures in year t, E_t is the electricity generation in year t, r is the discount (WACC), and n is the lifespan of the energy system. Second, high-quality wind generation regions are less ubiquitous than high-quality solar generation regions in the contiguous US. Furthermore, the capital cost of wind is significantly larger than solar power capacity. For this reason, power producers would only invest in wind generation capacity if it could produce a worthwhile amount of electricity generation to yield a low enough LCOE. The result of all of this is that new utility-scale wind generation installations are prioritized over solar in high wind capacity factor areas. The map of the EIA's Planned 2023 U.S. utility-scale generation resource provides empirical evidence for this [2]. In reality, the optimal wind-to-solar capacity ratio for hybrid wind and solar generation plants does not have a one-size-fits-all answer; it highly depends on several factors specific to the location and objectives of the project. Determining the ideal capacity ratio involves detailed analysis using modeling and simulation tools that consider all these variables. However, for the reasons listed above a 4:1 wind-to-solar ratio will be utilized and assumed to be optimal for the regions of the projects under study. Furthermore, a total generation capacity of 1,000 MW was modeled for each generation and load region. A 1,000 MW generation capacity was chosen to abide by a variety of constraints that includes SAM's maximum wind generation modeling capabilities.

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + M_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}} \tag{3.6}$$

In regards to the renewable energy resources modeled in the load region, the local alternative for renewable energy generation was taken into consideration. The objective was to identify the renewable energy generation resources that are planned to be developed in the near future, model them to obtain a PPA for energy generation, and then conduct the cost comparison analysis between the load region's generation PPA and the generation region's generation plus transmission delivery PPA. Fortunately, utility companies in many states across the county regularly conduct generation supply forecasting years in the future in a comprehensive energy demand and supply planning document referred to as an Integrated Resource Plan (IRP). The IRP of the predominant utility in each load region of the transmission project under study was utilized to identify the high-level details of the renewable energy generation plans [44][35][16][44][15]. As expected, the IRPs promote expanded development of local high-capacity factor renewables. Beyond that, there are also plans for the integration of diversified renewables and storage. Diversification typically occurs by means of the development of wind and solar, which are commonly recognized for exhibiting temporal complementarity. The temporal complementarity can be described as how these resources can complement each other over time, enhancing the stability of renewable energy supply [39]. In the regions where wind is not locally available, the general strategy appears to be utilizing storage to time-shift solar energy generation and pursuing the closest high-capacity factor wind generation via transmission. The foremost renewable energy and/or storage IRP plan for each transmission project was modeled in SAM.

After taking into account the aforementioned generation region's generation capacity and resource selection criteria, the generation's region generation facility for each project under study was modeled and analyzed. In addition, the load region's generation facility for each project under study was modeled and analyzed. Attention was focused on matching the combined wind and solar generation capacity across the generation and load region for each project to enable a direct PPA price comparison. The generation facilities for the generation and load regions are summarized in Table 3.5. Once the generation and storage resource modeling and analysis are completed in SAM, the output generation modeled profiles are analyzed along two criteria. The first is a price comparison between the total PPA price of the energy generation and transmission delivery from the generation region to the PPA price of the local alternative renewable energy generation in the load region. The second criterion is the renewable energy generation's performance in meeting a hypothetical 30% RPS target level.

Project	Generation Region - Generation Facility Capacity	Load Region - Generation Facility Capacity
Plains and Eastern	Wind - 800 MW, Solar - 200 MW	Solar 1,000 MW, Storage - 1,000 MWh
Grain Belt Express	Wind - 800 MW, Solar - 200 MW	Wind - 800 MW, Solar - 200 MW
SOO Green	Wind - 800 MW, Solar - 200 MW	Wind - 800 MW, Solar - 200 MW
Southern Spirit	Wind - 1,000 MW	Solar - 1,000 MW, Storage - 1,000 MWh
SunZia	Wind - 1,000 MW	Solar - 1,000 MW, Storage - 1,000 MWh

Table 3.5: Generation and Load Region SAM Modeled Generation Facilities

Capacity Contract Transmission Line Specification and Cost Estimation Analysis

The HVDC transmission line length specifications remain unchanged from the actual design of the projects under study to preserve the transmission route and generation and load region. However, the voltage class and power rating specifications are modified as a function of the modeled generation capacity. The transmission line power rating was assigned to be equal to the combined generation capacity of the projects under study, 1,000 MW. Assuming a standard balance of system load and losses for the generation resources, the generation output will never exceed the power, and this will have the desired effect of nearly maximizing the line's utilization when the generation output is at full capacity. The HVDC voltage class specification that aligns with this power rating is 400 kV. The HVDC resistive power dissipation, losses, are calculated by the identical analysis process as the energy arbitrage module.

After the transmission lines' specifications were set, the cost estimation was conducted using the *Transmission Cost Estimation Guide for MTEP 2023*. The analysis process was identical to the energy arbitrage module.

Capacity Contract Total PPA Price Calculation and Revenue Generation Analysis

The transmission PPA price component is calculated by solving for the transmission charge, priced in \$/MWh, that is needed to recover the cost of the project and earn a positive net return. Then the total system's PPA price is the summation of the generation region's PPA price and transmission PPA price. TBET conducts the transmission PPA price calculation after processing inputs of transmission cost estimation, the power flow across the transmission project under study, and the internal rate of return (IRR) value needed to yield a positive rate of return. To obtain the transmission PPA price, TBET's capacity contract module essentially simulates the flow of power across the project under study that is sourced on an hourly basis from the generation region and consumed by the load region. Each MW delivered per hour generates revenue at the \$/MWh PPA price over the project's lifespan, and each year incurs either the implementation or expense factor cost. The NPV module's functions are utilized to discount the future term's revenue and cost. Finally, the resulting output of the capacity contract module is the total PPA price of the system and the annual revenue generation of the transmission project under study. This analysis process is displayed in the flowchart in Figure A-2 in Appendix A.

3.3.5 NPV Modeling

The NPV module of the TBET serves as the flexible framework that evaluates the value of an investment in transmission development. It supports project valuation for both the energy arbitrage, merchant, and capacity contract cost recovery mechanisms; thus, the NPV module is utilized by both energy arbitrage and capacity contract modules. Fundamentally, the NPV module is generalized to adhere to the standard NPV methodology regardless of the selected cost recovery mechanism. It calculates the difference between the present value of cash inflows (revenues from energy sales and any other financial benefits) and the present value of cash outflows (initial capital investment, operating and maintenance costs, and any other expenses) over the lifetime of the project. By discounting future cash flows to their present value using a specified discount rate, NPV provides a measure of each project's profitability and financial viability. Importantly, the resulting NPV metric enables transmission project developers to objectively compare projects and rank them accordingly. This is the analog to transmission project multi-value cost-benefit analysis that guides economic transmission planning. The use of a consistent valuation and then prioritization methodology here is important for alignment with best practices.

The cash inflows for the NPV module come from the revenue stream of energy sales from the energy arbitrage or capacity contract modules. Fundamentally, the revenue streams from both modules are ex-ante forecasting which involves making predictions about future revenue generation before the event or action occurs. This makes the revenue values inherently uncertain and conditional on modeling accuracy relative to real energy markets and operations. As stated in the assumptions for each model, numerous simplifications are made for ease of modeling and estimating stochastic processes. However, this revenue stream uncertainty is mitigated by considering a multitude of future scenarios as in the case of the averaging of energy arbitrage value NPVs across Cambium future projections of the electricity landscape. Similarly, the capacity contract module leverages contractual agreements to reduce uncertainty and risk by fixing PPA prices.

Transmission implementation cost (initial capital investment), O&M, and other reoccurring expenses constitute the cash outflows for the NPV module. As noted, in the energy arbitrage and capacity contract modules, the cost modeling approach is based on MISO's standardized guide for exploratory transmission cost estimation. MISO and other transmission oversight and planning entities find value in such models for early-stage evaluations of cost, and their experience in this realm provides a level of legitimacy to this approach. Furthermore, contingency cost adders help to account for uncertainty by pricing additional costs that could be incurred.

Independent transmission developers use the discount rate in financial analysis to serve as a method to account for the average cost of financing a company's assets, reflecting both debt and equity. However, independent transmission development outside of the conventional regulated rate of return cost recovery model does not have a lot of historical examples to learn or get an understanding of investor sentiment. For this reason alone, the WACC will have to account for an additional risk premium relative to the regulated rate of return transmission investments due to the inherent uncertainty of cost recovery and net positive returns.

3.3.6 NPV Analysis

The cash inflows on an annual basis come directly from the output of the energy arbitrage and capacity contract module and do not require much additional processing for NPV calculations. The NPV specified WACC for transmission development is set to a nominal value of 8% to reflect a risk premium above the IPP's nominal WACC of 6% sourced from the NREL report on the WACC of renewable energy generation technology.

Transmission Cost Estimation Guide for MTEP 2023 provides a methodology to allocate a transmission project's implementation and recurring cost over a specified time span to produce annualized cash outflows. The implementation cost is split over a 5-year construction period according to the project spend schedule provided in Figure 3-5 [50]. Then, from year 6 to the end of the project's estimated 25-year lifespan, the re-occurring land lease and O&M cost quantified by the expense factor are incurred.

Estimated 5-year project spend						
Year	2*	3	4	5	6	Subtotal
Costs incurred per year	2%	3%	10%	45%	40%	100%
Present year project implementation cost	$2.6M	$3.9M	$12.9M	$58.0M	$51.6M	$129.0M

Figure 3-5: Estimated Implementation Cost Annual Allocation

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Chapter 4

Results and Discussion

4.1 Energy Arbitrage Results

Energy arbitrage analysis was conducted on the projects under study in accordance with the methodology described in the methods section. The intention of TBET's analysis was not absolute accuracy in modeling or analysis but instead to enable the capability to heuristically evaluate critical components of multi-value benefits of transmission. Although there are no publicly available quantitative measurements of the multi-value benefits of each project to compare results to, the developers of these projects state that these projects provide noteworthy benefits of access to low-cost energy to load centers and improvements of reliability and resilience. The results of this analysis will be compared to these claims.

Furthermore, the transmission projects under study are merchant investments and are intended to recover cost in a manner similar to TBET's energy arbitrage and capacity contract module analysis (publicly available information for each project has primarily mentioned the capacity contract cost-recovery mechanisms, but energy arbitrage also a possibility). The results reviewed in this section will evaluate the business viability of the merchant investment.

4.1.1 Historic Energy Arbitrage Results

Historical energy arbitrage analysis provides an idea of the value, quantified by the inflow revenue stream, gained if the transmission line was in commission during the previous few years (2019-2022). This value will be referred to as the historic energy value. Notably, the historic energy value results were the product of a relatively straightforward market forecasting strategy that predicts the prices of the forecasted hour will match the prices of the preceding hour in the real-time market simulation of the historical energy arbitrage analysis. This market forecasting strategy is simple enough to easily employ in practice and is therefore informative of reasonable energy value that can be gained from the projects under study.

The historic energy value yielded from historical real-world market volatility, mainly tail-event, inclement weather conditions, and notable macroeconomic trends are of particular interest. Within the historical years of 2019-2022, two notable winter storms caused significant generation and transmission outages concurrent with a dramatic increase in electricity demand. Winter Storm Uri occurred from February 13-17, 2021, and the imbalance between high demand and low supply led to soaring electricity prices. In Texas, prices hit the market cap of $9,000 per megawatt-hour. Winter Storm Elliott from December 21 to 26, 2022, while less impactful on the electricity sector than Uri, still caused significant disruptions to generation and price spikes in several RTO/ISO markets. The historic energy value gained during these storms is directly due to the transmission lines under study responding to the significantly high-cost energy areas from generation disruptions and flowing power to provide lower-cost energy to these areas. This is essentially the objective of transmission resilience, and therefore, the historic energy value attributed to these events is separated from the remaining historic energy value and assigned to the resilience benefit value of the projects under study. The remaining historic energy value can be assigned to the production cost-benefit value of the projects under study. However, this historical analysis is backward-looking and is less informative than the desired forward-looking results of the future energy arbitrage analysis. For this reason, the future energy arbitrage results are more suitable for assigning production cost benefits. As noted in the energy arbitrage modeling section, SunZia was not analyzed for historical energy arbitrage value due to the unavailability of wholesale electricity data in the West Connect transmission planning region where this project resides. Table 4.1 displays the results of the total historic energy value accrued during extreme events value (resilience benefit) and average annual historic energy value (production cost benefit) for the HVDC 400 kV line specification configuration of the projects under study.

Project	**2021-2022 Total Extreme Events Value ($Millions)**	**Average Annual Historical Energy Value ($Millions)**
Plains and Eastern - HVDC 400 KV	$105	$109
Grain Belt Express - HVDC 400 KV	$124	$149
SOO Green - HVDC 400 KV	$28	$41
Southern Spirit - HVDC 400 KV	$978	$98

Table 4.1: Total Extreme Events Value (Resilience Benefit) and Average Annual Energy Value (Production Cost Benefit) of Projects Under Study

Furthermore, the remaining historic energy value after filtering total extreme value is analyzed to identify correlations to macroeconomic trends, such as changes in generation fuel prices, electricity demand, and renewable energy penetration. Over the short time scale of four years that is analyzed for historical energy arbitrage analysis of the projects under study, changes in generation fuel prices are the macroeconomic trend that makes a noticeable impact from year to year. As a result of natural gas being the U.S.'s predominant electricity generation fuel source over recent years and production cost constituting a major component of wholesale electricity prices, historical LMPs in land-constrained and renewable resource-scarce areas correlate highly with natural gas prices, whereas areas with high integration of renewable generation will correlate less. The result of this is that the historic energy value for the projects under study, which arbitrage energy from a high renewable energy resource area to comparatively lower capacity-factor renewable energy resource areas, will correlate with the cost of natural gas prices. This correlation is shown in Figure 4-1 for the energy arbitrage revenue yielded from the perfect foresight market forecasting strategy, which captures the ceiling of possible energy arbitrage revenue generation, of the projects under study. The perfect market foresight results are useful for trend comparisons such as this because they best provide information on direct results that are not diluted by forecasting errors.

Along with production fuel commodity prices, the other noted macroeconomic factors of changes in electricity demand stimulated by electrification, and electrical energy prices due to renewable energy integration affect wholesale market prices and hence energy arbitrage revenue. These factors are accounted for in the subsequent scenario-based future energy arbitrage analysis.

4.1.2 Future Energy Arbitrage Results

A consequence of the use of forward-looking analysis and the use of Cambium's forecasted LMPs is that the inherent uncertainty of the behavior and trends of electricity price driving factors necessitate the need for multi-scenario based analysis. The Cambium scenarios account for macroeconomic factors related to generation production cost, changes in electricity demand, and renewable energy integration mentioned in the historical energy arbitrage analysis section. In addition to these, there are scenarios that model the impact of the U.S. reaching high levels of decarbonization by 2035 and 2050 along with previously mentioned macroeconomic trends in conjunction with tax credit phaseouts.

Future energy arbitrage analysis provides an idea of the value, quantified by the inflow revenue stream, gained by the transmission line during the aforementioned scenario-based, projected years of 2024-2050. These resulting values will be referred to as the future energy value and will be prefixed when appropriate by the scenario that is being referenced. The broad range of modeled scenarios is helpful to consider the impact of various factors on future energy value results. The likelihood of any individual modeled scenarios predicting future LMPs within a tight enough confidence interval to pursue energy arbitrage as a viable cost recovery mechanism is slim.

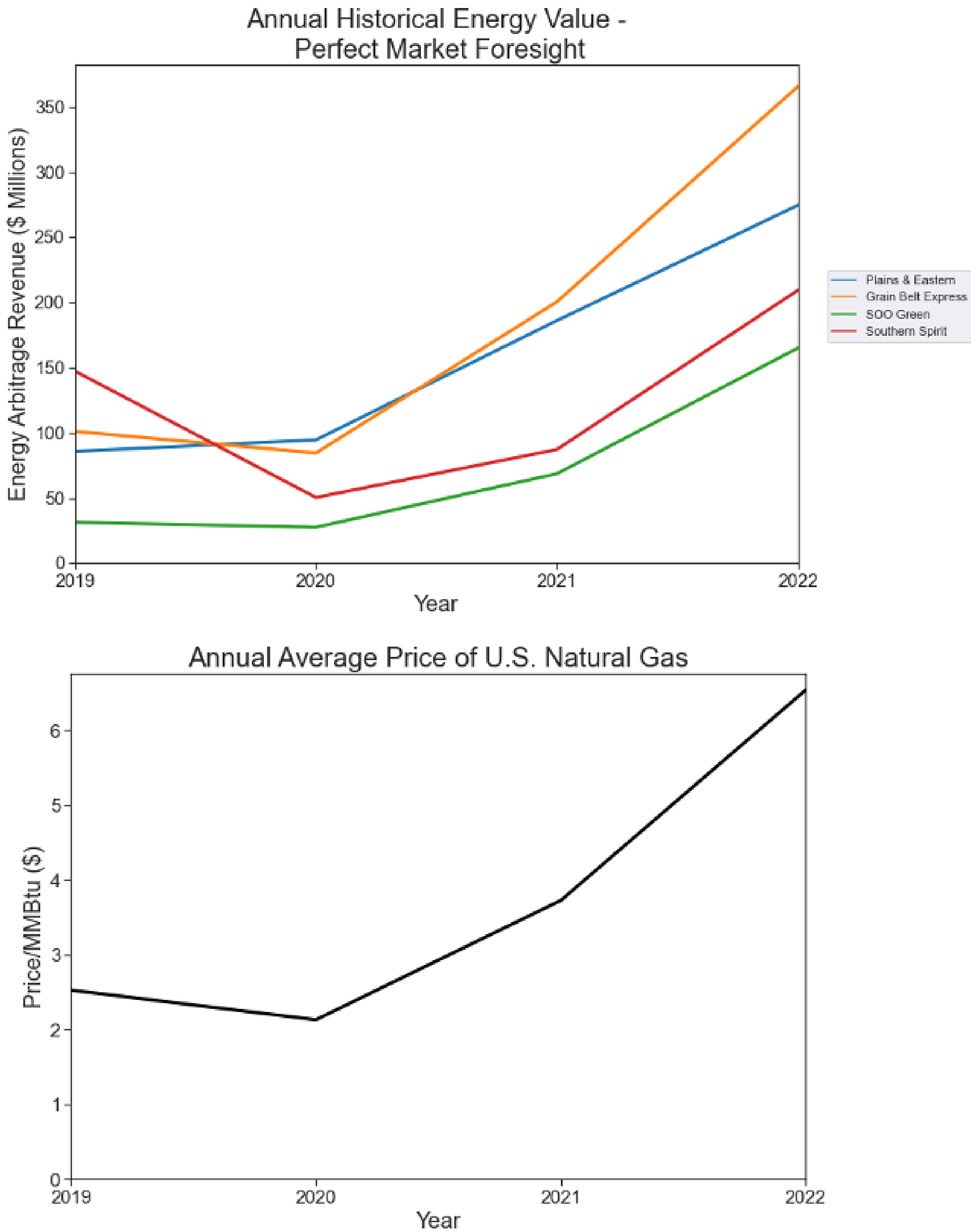


Figure 4-1: Historic Energy Value Comparison to Natural Gas Prices

However, the future energy value results are at the very least indicative of the future directionality of project revenue streams. Figure 4-2 displays the combined historical energy value with future energy value results of a high natural gas price future energy value. The starting date of the future energy arbitrage revenue 2024 is distinguished by the large revenue drop from the historical 2022 revenue. This shows that although Cambium's forecast is accounting for a high natural gas price future, it does not align very closely with the 2022 energy arbitrage revenue streams induced by historically high natural gas prices. Still, the projects are directionally aligned from historical to future analysis as the energy arbitrage revenue stream generally continues to increase from historical to future years. Furthermore, the three top-performing projects in historic years, Grain Belt Express, Plains & Eastern, and Southern Spirit consistently outperform SOO Green.

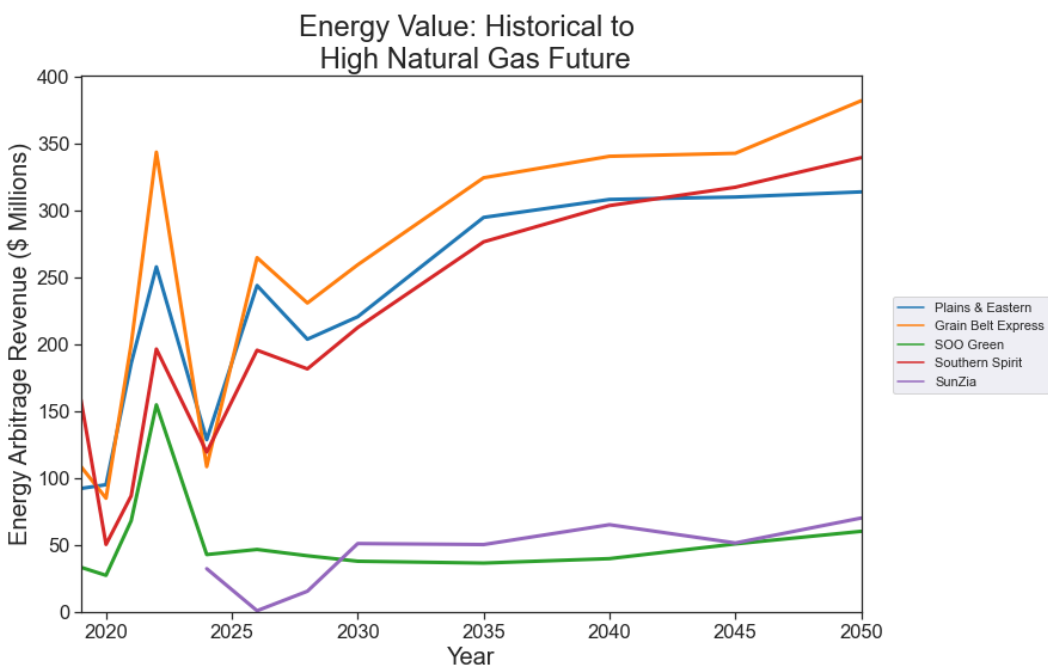
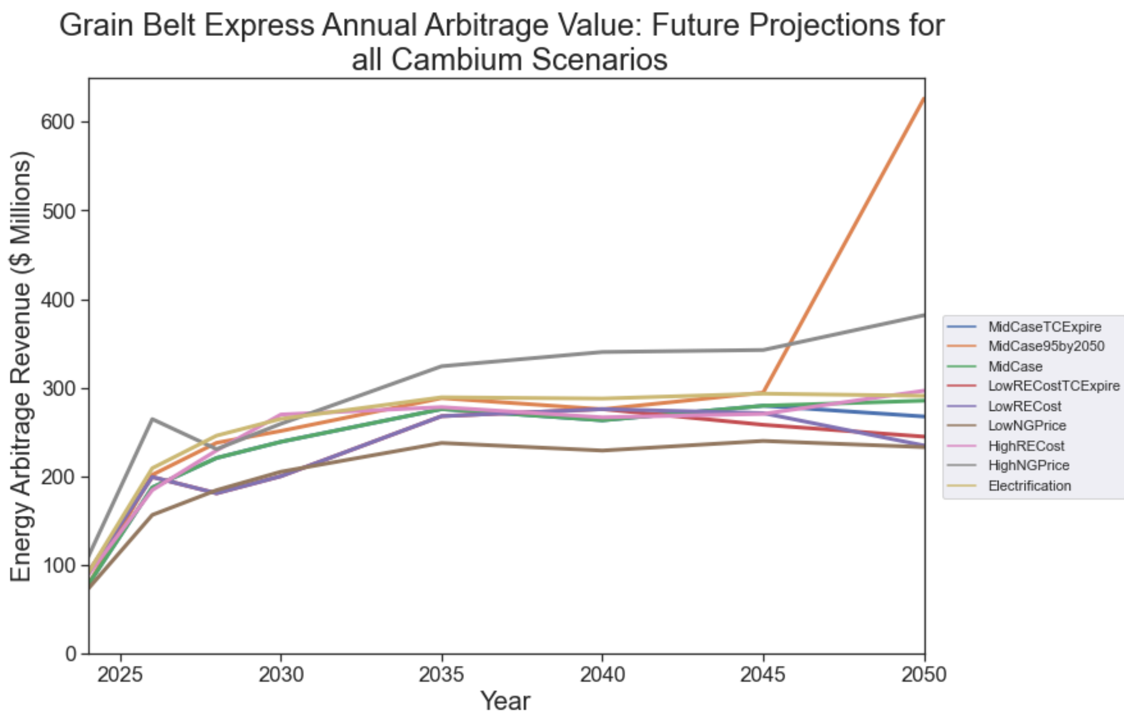


Figure 4-2: Historical to High Natural Gas Future Energy Value

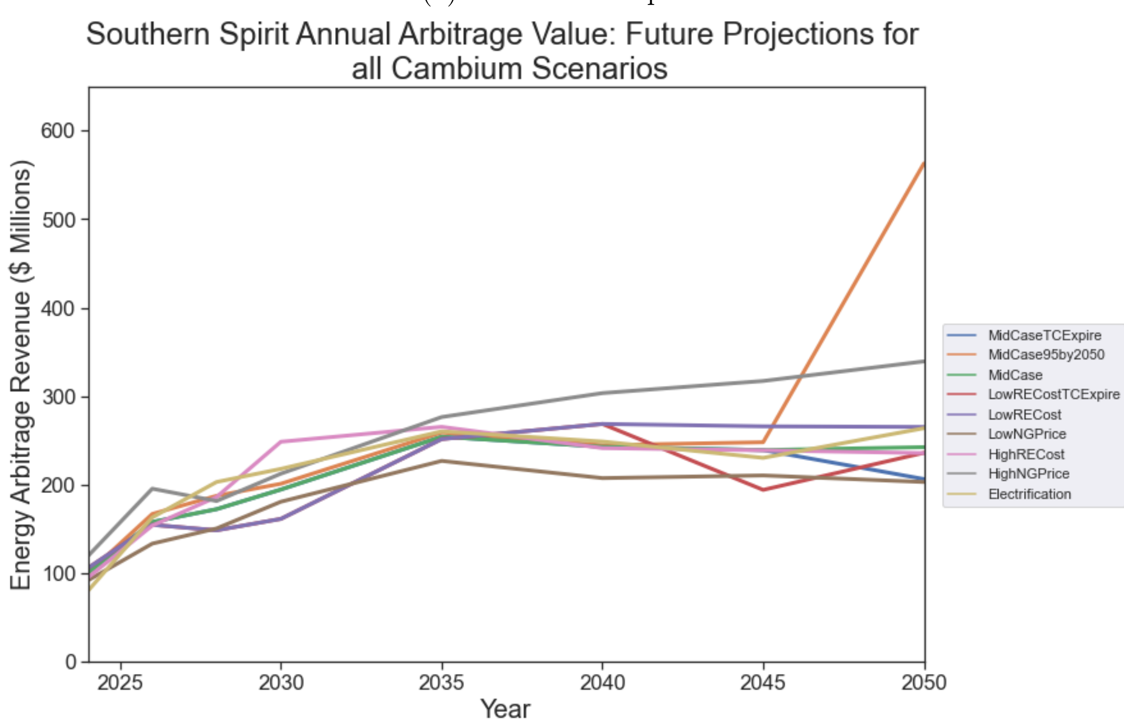
Due to inherent limitations of electricity sector forecasting that include the inability of a single model scenario to forecast future revenue accurately and the lack of representation of market volatility within any particular scenario, there is a clear importance to aggregate multiple scenarios together for more informed and realistic energy arbitrage revenue considerations. Expanding upon this further, the aggregating process helps project developers understand the range of potential outcomes and prepare for a variety of future conditions. For any given transmission project under study, the magnitude of future energy value exhibits a relatively wide range across the modeled scenarios, but the direction of each scenario's future energy value going forward into increasingly later years is generally consistent. In other words, generally, all scenario's future energy values together move in the same direction from 2024 to 2050. Figure 4-3(a) and Figure4-3(b) depict this consistent forward direction trend for the multi-scenario future energy value results for the Grain Belt Express and Southern Spirit projects respectively.

The aggregation of multiple scenarios in future energy arbitrage analysis should be done in an informed manner. Ideally, a methodology should be created to devise a scenario weighting methodology for aggregations based on the magnitude of each scenario and the probability of occurrence. Empirical evidence of the impacts and occurrences of electricity market factors may be able to inform such methodologies, and there is some evidence available within historical electricity market data. However, it would be difficult to soundly reason that historical evidence will accurately inform future impact and occurrence with a rapidly changing electricity sector. For instance, the development and grid interconnection of low-cost, renewable energy is presently happening at a rate faster than ever before seen according to the EIA's 2023 Solar and Wind growth report [3]. Therefore, this paper proposes that the best alternative is to use domain judgment to exclude significantly lower likelihood scenarios and then equally weight the other scenarios. For this reason, the "100% Decarbonization by 2035" Cambium scenario was excluded from the analysis altogether since most states' RPS standards are not set to meet this goal by the target year, and there is no federal policy to enforce this. The 9 remaining scenarios are considered and equally weighted for NPV calculations of energy arbitrage value.

Furthermore, the inclusion of multiple scenarios in the future energy value enables the evaluation of another multi-value benefit, the risk mitigation benefit. In accordance with the ESIG multi-value framework, the risk mitigation benefit value is evaluated



(a) Grain Belt Express



(b) Southern Spirit

Figure 4-3: Future Energy Value: All Modeled Scenarios by quantifying the production cost savings across a range of future scenarios of the electricity sector [33]. For the future energy value scenario-based results, this translates to comparing the worst case future energy value results to the best case energy value results with the mid case being the benchmark, all for the final year of energy value (2050). The mid case for the Cambium scenarios is suitably labeled, "Midcase". Following ESIG's risk mitigation evaluation methodology, the mid case energy value is subtracted from the best case energy value, and the worst case energy value is subtracted from the mid case energy value for each project under study. Then, the two resulting energy value differences are converted to a single risk mitigation benefit value by simply calculating the range of the differences [33]. This risk mitigation benefit evaluation process and resulting values for each project under study are provided in Table 4.2.

Project	**Best Case Scenario Future Energy Value ($Millions)**	**Mid Case Scenario Future Energy Value ($Millions)**	**Worst Case Scenario Future Energy Value ($Millions)**	**Risk Mitigation Benefit Value ($Millions)**
Plains and Eastern - HVDC 400 KV	$473	$236	$208	$209
Grain Belt Express - HVDC 400 KV	$632	$286	$241	$301
SOO Green - HVDC 400 KV	$142	$42	$38	$96
Southern Spirit - HVDC 400 KV	$569	$235	$203	$302
SunZia - HVDC 400 KV	$188	$33	$23	$145

Table 4.2: Risk Mitigation Benefit Value of Projects Under Study

4.1.3 Averaged Scenario NPV Energy Value

After the transmission projects under study undergo future energy arbitrage analysis across the selected scenarios of the electricity sector, the value (revenue stream) for each scenario is attributed as a cash inflow, subtracted by the transmission installation cost and reoccurring expenses that constitute the cash outflows, and then discounted by the WACC to produce an NPV for each project across each scenario. Table 4.3 displays the average scenario NPV energy value result for this process for both the HVDC 400 kV and HVAC 345 kV transmission line specifications.

Project	**Averaged Scenario NPV of Energy Value($Millions) - HVDC 400 kV**	**Averaged Scenario NPV of Energy Value($Millions) - HVAC 345 kV**
Plains and Eastern	-$272	-$1,041
Grain Belt Express	-$105	-$988
SOO Green	-$1,302	-$994
Southern Spirit	$432	
SunZia	-$1,328	-$1,085

Table 4.3: Averaged Scenario NPV Energy Value of Project Under Study

From the results, it is clear that only the modeled Southern Spirit project yields business-viable, positive NPV. As indicated in section 3.1, Southern Spirit is a relatively short transmission line (395 miles) as compared to the other projects under study such as Grain Belt Express (790 miles), so it inherently has lower cost expenses. More importantly, Southern Spirit builds a transmission connection between regions that do not currently have any existing direct interregional transfer capability between them [37]. By connecting Texas-based ERCOT ISO to MISO, this project provides the capability to deliver bi-directional power transfer capacity between these two regions. More generally, it appears that energy arbitrage cost recovery generally favors transmission lines that connect regions that have limited existing interregional transfer capacity. In such cases, transmission congestion induces large electricity price differences across regions. Therefore, a transmission line with a connection to a POR in a low-cost generation can make a significant impact by supplying this low-cost generation to the POD and effectively reducing congestion.

4.2 Energy Arbitrage Results Discussion

The NPV of energy value serves both as a heuristic for the production cost benefits relative to installation cost and a metric for evaluating the cost recovery viability of merchant transmission investment of the projects under study.

Although the NPV of energy value only directly accounts for the production cost savings component of the comprehensive transmission value, the production cost savings value is the critical component that can be most easily captured by the merchant investor to recover the cost of the transmission project. In addition, other components of the multi-value benefits are implicitly accounted for in the energy value as demonstrated by the resilience, and risk mitigation benefit value evaluation derived from the historical and future energy value results. Nevertheless, the rather disappointing NPV of energy value results across the projects under study indicates that the merchant investor must find a way to incorporate and capture the entire multi-value benefits of the projects to make the energy arbitrage cost-recovery mechanism business viable for all projects.

4.3 Capacity Contract Results

The projects under study are all relatively long-range transmission projects that are capital-intensive. The contemporary line of reasoning for merchant transmission investments is that these types of transmission projects can more readily demonstrate business viability with the capacity contract cost recovery mechanism. Capacity contracts, contractual agreements for energy generation and delivery via transmission to an offtaker enable more flexibility to incorporate and capture multi-value benefits and ultimately yield positive NPV for the projects. In contrast to energy arbitrage, the renewable energy resources in the generation region are modeled and precisely priced rather than vaguely represented by an LMP from the wholesale electricity market. A precise price signal yields more information on the production cost savings and can result in an improved analysis of the production cost benefits. In addition, the environmental benefits of these projects can be accounted for by analyzing the amount of renewable energy that can be generated and delivered to satisfy the load region's RPS target.

As a review of the capacity contract methodology covered in section 3.3, the objective is to demonstrate that the projects under study cost of renewable energy generation and transmission provide a lower total PPA than the local alternative in the load region and improve alignment towards RPS targets. Then, a logic-based argument can be made that the transmission project will be the optimal option for the offtaker. Furthermore, the cost of delivery via transmission is configured to a set price to ensure that the forecasted amount of power that flows across the line over the life of the projects will yield favorable IRR and net positive earnings. Therefore, as long as the total energy generation and transmission prices are contractually agreed upon by the load entity, off-taker, the transmission project will be theoretically business viable.

4.3.1 Capacity Contract Results for the Equalized Generation Capacity Constraint

The comparison process is first conducted with the constraint that the renewable energy generation capacity at the generation node and load node are equivalent (1,000 MW), which includes battery storage (1,000 MWh) added to load regions that do not have high capacity factor wind resources. A description of the modeled generation facilities for the generation region and load region of the projects under study are displayed again for the reader's convenience in Table 4.4, and the results of the comparison are displayed in Table 4.5.

Under the equalized generation capacity constraint, the projects with generation regions of solely wind generation, Southern Spirit and SunZia, are more cost competitive than the cost of the local alternative of solar and storage at the load region. These

Project	Generation Region - Generation Facility Capacity	Load Region - Generation Facility Capacity
Plains and Eastern	Wind - 800 MW, Solar - 200 MW	Solar 1,000 MW, Storage - 1,000 MWh
Grain Belt Express	Wind - 800 MW, Solar - 200 MW	Wind - 800 MW, Solar - 200 MW
SOO Green	Wind - 800 MW, Solar - 200 MW	Wind - 800 MW, Solar - 200 MW
Southern Spirit	Wind - 1,000 MW	Solar - 1,000 MW, Storage - 1,000 MWh
SunZia	Wind - 1,000 MW	Solar - 1,000 MW, Storage - 1,000 MWh

Table 4.4: Generation and Load Region Generation Facilities

two projects are business viable based on PPA price comparison alone and developing transmission to access wind generation is a cost-favorable option in comparison to locally developing solar and storage for the load region. This is mainly driven by the low LCOE of wind generation in the generation regions in comparison to solar generation in the load regions. In contrast, the projects with generation nodes of wind and solar generation are not more cost-competitive than their respective local alternatives. However, once taking into account the RPS of 30% electrical energy demand served by renewable energy generation, all projects demonstrate a larger renewable power generation (MW) for 30% of hours when compared to the local alternative generation at the load region. Generation duration curves, which visualize the amount of power generated by a generation facility over time, are particularly useful for analyzing the availability and variability of power generation. For this RPS target analysis, they are used to display the amount of power generated by the generation and load regions' generation facilities as a function of the percentage of hours in a year; thus, a duration curve displays the amount of power that can be generated by the generation facilities for the RPS target of 30% of hours. Figure 4-4 shows the generation duration curve for the Plains and Eastern project's generation and load region (Memphis, Tennessee) and a reference line for the RPS target of 30%

Project	PPA Price Generation ($/MWh)	PPA Price Transmission ($/MWh)	PPA Price Total ($/MWh)	PPA Price Local Alternative ($/MWh)
Plains and Eastern	$40.90	$53.10	$94.00	$77.50
Grain Belt Express	$42.30	$54.30	$96.60	$63.30
SOO Green	$43.00	$41.80	$84.80	$65.20
Southern Spirit	$32.40	$37.40	$69.80	$77.50
SunZia	$22.70	$37.50	$60.20	$61.50

Table 4.5: Equalized Generation Capacity Contract Results

of hours. The Plains and Eastern project exhibits the largest difference in renewable power generation for the 30% RPS target between the generation and load region, 480 MW. Although the cost of the Plains and Eastern solar and wind energy in the generation region plus transmission delivery is 20% higher than the local alternative of solar and storage in the load region, it generates over 200% more renewable energy for the 30% RPS target.

4.3.2 Capacity Contract Results for the Equalized Renewable Power Generation at 30% RPS Target

The observed difference in renewable power generation for the 30% RPS target across the projects under study raises an interesting inquiry, "How much annual average energy demand could be satisfied by local renewable energy generation in the load region if the generation capacity was increased?" To address this question, the constraint that sets the equivalent generation capacity between generation and load regions is removed, and the generation and storage capacity is increased in the load region. This effectively sets a requirement that the local renewable energy in the load region must match the generation region's annual average generation for the 30% RPS target, and it is a heuristic approach to account for the generation capital cost benefit of the project under study.

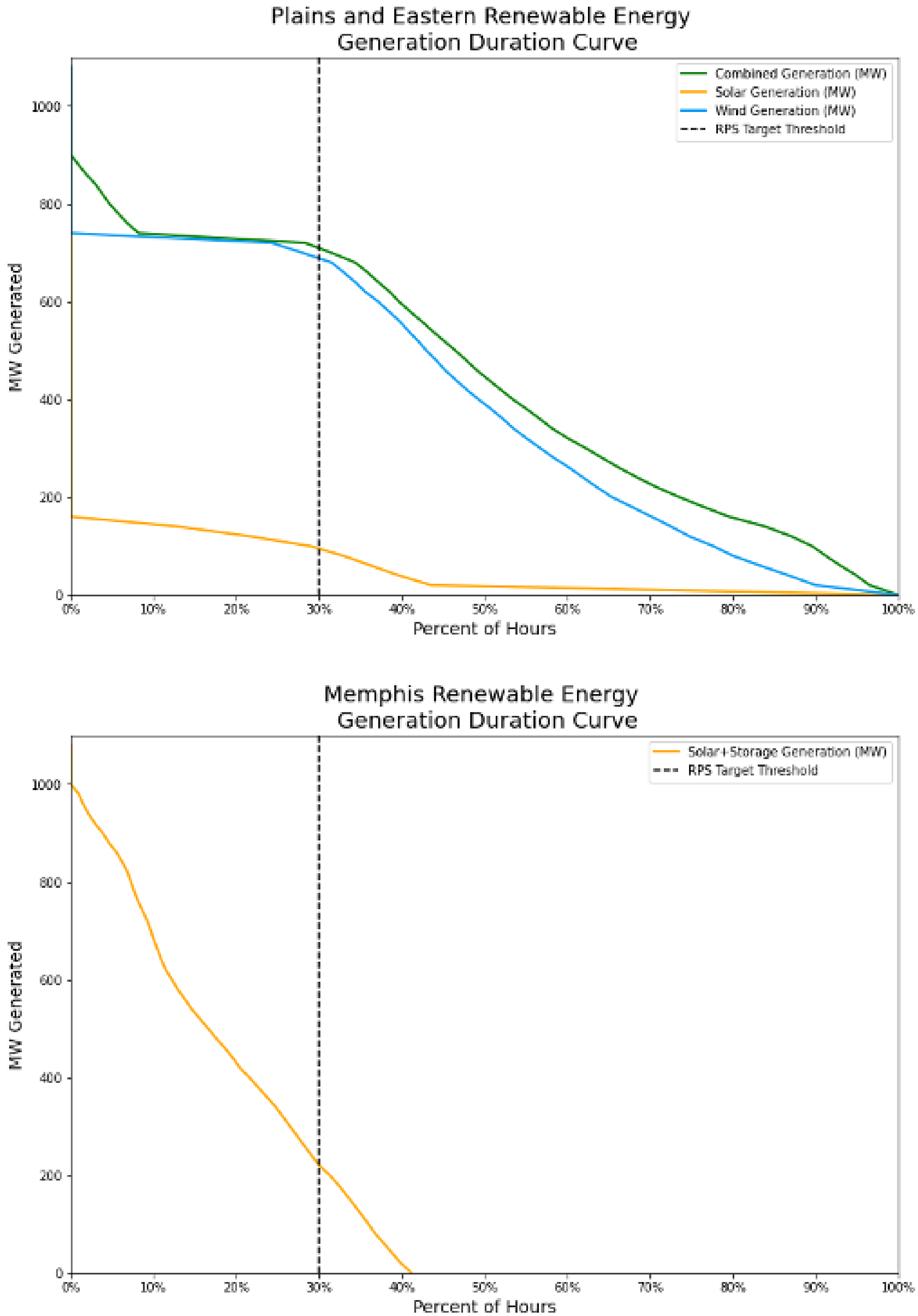


Figure 4-4: Plains and Eastern Equalized Capacity Generation Duration Curve Comparison

For the project load regions without storage, the generation capacity was increased to match the annual average energy generation at 30% of the generation region. For the projects with load regions that have storage, the storage was increased in proportion to the increased generation capacity. Since the Southern Spirit and Plains and Eastern projects are already more cost-competitive than the load region's local alternative, they are omitted from this subsequent analysis. A description of the RPS target, updated modeled generation facilities for the generation region and load region of the projects under study are displayed in Table 4.6, and the results of this analysis are displayed in Table 4.7.

Project	**Generation Region - Generation Facility Capacity**	**Load Region - Generation Facility Capacity**
Plains and Eastern	Wind - 800 MW, Solar - 200 MW	Solar 3,000 MW, Storage - 3,000 MWh
Grain Belt Express	Wind - 800 MW, Solar - 200 MW	Wind - 1,350 MW, Solar - 338 MW
SOO Green	Wind - 800 MW, Solar - 200 MW	Wind - 1,350 MW, Solar - 338 MW

Table 4.6: Generation and Load Region Generation Facilities Adjusted for Equalized Renewable Energy Generation for 30% RPS Target

Project	**PPA Price Generation ($/MWh)**	**PPA Price Transmission ($/MWh)**	**PPA Price Total ($/MWh)**	**PPA Price Local Alternative ($/MWh)**
Plains and Eastern	$40.90	$53.10	$94.00	$125.50
Grain Belt Express	$42.30	$54.30	$96.60	$63.30
SOO Green	$43.00	$41.80	$84.80	$65.20

Table 4.7: Equalized Renewable Power Generation for 30% RPS Target Capacity Contract Results

The results of the equalized renewable power generation for 30% RPS target analysis for the Plains and Eastern project are especially informative. In order to equalize the renewable power generation at 30% of hours for the generation and load region, the load region's solar capacity had to be increased to 3,000 MW and the storage capacity increased to 3,000 MWh. As a result, the PPA price of the load region's local alternative is significantly more expensive than the total PPA price of the Plains and Eastern project. The significant increase in PPA price in the load region is primarily a result of the present-day, relatively high cost of the predominant grid-scale storage technology, lithium-ion. Although grid-scale storage helps to shift solar output across time and essentially flatten out the duration curve produced by solar, the same generation duration flattening effect can be done more cost-competitively with wind generation in high capacity factor geographic areas. The Plains and Eastern project generation region in northwest Oklahoma is a great example of such a high capacity factor wind area (greater than 40% wind capacity factor). Therefore, the Plains and Eastern wind and solar facilities in the generation region produce a total PPA price that soundly beats out the PPA price of the solar and storage facilities in the load region. Figure B-1 in Appendix B displays the Plains and Eastern project's equalized renewable power generation duration curves for the load region.

4.4 Capacity Contract Results Discussion

The results of the subsequent analysis of the Grain Belt Express and SOO Green projects that matched the annual average energy generation at an RPS target of 30% across generation and load regions are more nuanced. Increasing the generation capacity of the wind and solar resources in these areas did not affect the PPA prices. This is because the ratio of wind-to-solar capacity was kept constant at 4:1, and the LCOE did not significantly change. Hence, the PPA price needed to provide a standard 8% IRR remained the same. The most meaningful change was that it required an additional 550 MW of wind capacity and 138 MW of solar capacity to obtain the same annual average energy generation at an RPS target of 30%. This translates to a significantly larger capital cost and land area allocation for the installation of the additional capacity. Of course, in practice, the PPA price is generally set to ensure that the developer of the renewable energy generation facility in the load region will make a standard IRR over the course of the project. However, the land allocation needed for the project can be a serious issue for land-constrained and densely populated areas. For instance, NREL SAM's modeling tool estimates that developing the 1,350 MW wind farm in SOO Green's load region could take over 170 square miles of land area. This land allocation would realistically be split across multiple farms that all interconnect to the bulk electricity system. ComEd, the leading utility in the Chicago area that SOO Green connects to, currently has 13 active wind projects underway that have a combined capacity of 3,120 MW, so this is very feasible [17]. The same can likely be said for the Grain Belt Express project's load region that lies on the border of Illinois and Indiana. It can still be reasoned that as RPS targets increase to 100% energy supplied by renewable and clean energy within the next few decades, states will need more access to low-cost and high-capacity factor renewable energy resources such as those provided by the projects under study.

The intention of the capacity contract analysis conducted by TBET was to improve the analysis of the production cost benefits and account for the generation capital cost benefits of the projects under study. Then, it could be demonstrated that the projects can be economically viable based on these value streams. Yet, the Grain Belt Express and SOO Green projects still are not business viable in this model. This means that there is additional value to these projects, and likely the other projects under study, besides providing lower cost of renewable energy to the areas they connect to. Upon further investigation into these projects, this inference is seemingly validated by the value specified by the transmission developers of these projects. For example, the developer of the Grain Belt Express project, Invenergy, specifies that the project will diversify the energy mix available to the offtakers in the load region and resultingly will deliver reliability benefits. SOO Green's project developers also cite system-level reliability and further benefits for their project.

Critical components of the multi-value benefits are accounted for in the capacity contract analysis as demonstrated by the production cost savings and generation capital cost reduction value evaluation in the equalized generation capacity and equalized renewable power generation analysis respectively. Still, the entire multi-value benefits of the projects should be incorporated to demonstrate that each project is a more economical option relative to its respective local alternative; thus, making the project's business viable.

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Chapter 5

Conclusion and Future Work

5.1 Energy Arbitrage Module Insights

The results of the energy arbitrage analysis revealed that the analysis is informative of several components of multi-value benefits. Yet, for most projects under study, the NPV of energy value yielded from these component values fell significantly short of the value needed to recover the cost of the projects. It was then established that the merchant investor must use the multi-value benefits framework to accurately evaluate the comprehensive value of a transmission project and then capture this value to make the energy arbitrage cost-recovery mechanism business viable for all projects. The TBET energy arbitrage module prioritizes computational resource reduction over complete accuracy as noted by the modeling assumptions and simplifications identified in section 3.3. It is insightful to review the qualitative effects of the modeling assumptions on the multi-value benefits evaluation and subsequent cost recovery analysis.

5.1.1 Evaluating Multi-value Benefits with Energy Arbitrage Analysis

Due to the use of a price-taker model approach and the adoption of the resulting modeling assumptions, the resulting production cost benefit values are directionally indicative at best. Cambium's future forecast of LMPs does account for the impact of scenario-based transmission expansion on LMPs, but the impact is generalized across a large balancing authority area and is not precise for any specific project under study. Nevertheless, the price-taker assumptions are deemed sufficient to use for the early-stage, analysis to heuristically measure the production cost savings benefit.

In regards to the resilience benefit values obtained from the historical energy arbitrage analysis, these values are derived from historical occurrences of extreme weather events over a relatively short duration of time, four years. To qualify this obtained value as characteristic of the actual resilience value of the projects under study, a collection of assumptions must be made. The assumptions are: the occurrence of extreme weather events will continue at the frequency it did over the historical four-year time period, the broader, interconnected transmission system will not significantly change in the future to mitigate the effects of such events, and RTO/ISO oversight over energy dispatch and market operations will not implement wholesale electricity price control policies. The first assumption is difficult to prove or disprove with empirical data, but the other two assumptions are easily disproved with observations and policies implemented since the extreme events occurred. There is a wealth of regulated and merchant investments in transmission projects (including the projects under study) that are seeking to make the grid more reliable and resilient to mitigate the effects of extreme weather events. Furthermore, the predominant ISO in Texas, ERCOT, lowered its price cap from \$9,000/MWh to \$5,000/MWh soon after Winter Storm Uri [18]. Therefore, the use of the historical energy arbitrage obtained resilience value is not practical for cost-recover considerations, however, it is at least informative.

The risk mitigation benefit value was estimated with the use of Cambium's scenario-based, future forecast of LMPs. Following ESIG's multi-value benefits framework, this value should include probability weighting for each scenario and intra-scenario price volatility. However, to obtain these stochastic-driven considerations, a significant amount of data processing and analysis would need to be conducted with more advanced energy system models such as PCMs. As a result, the TBET energy arbitrage module's evaluation of risk mitigation benefit value is less accurate.

Evaluation of the remaining multi-value benefit categories requires extensive modeling of existing electric grid infrastructure including generators, market operations, and transmission contingency occurrences that model the effect transmission system outages have on LMPs. This modeling requirement is computationally demanding and is therefore beyond the scope of this study. It is important to acknowledge that prominent independent transmission developers such as NEET will have the computational resources and capabilities to evaluate the comprehensive multi-value benefits of proposed transmission projects. However, such an analysis can be unfeasible to replicate across a large collection of early-stage, project plans. Therefore, the TBET's computationally-reduced, energy arbitrage analysis can identify the projects that demonstrate high energy value, which includes critical components of multi-value benefits, so that these projects can be prioritized for a comprehensive multi-value benefits evaluation.

5.1.2 Energy Arbitrage Cost Recovery Insights

The energy arbitrage analysis results of the projects under study demonstrate that interregional transmission lines between regions that have limited existing transfer capacity business can be business viable for merchant transmission investment. Still, the exposure to wholesale market prices for the energy arbitrage cost recovery mechanism is deemed unacceptably risky for most transmission investors. As a result, there are no existing transmission projects in the U.S. that recover costs entirely based on energy arbitrage [38].

There is also a concern that if such a transmission project was developed to recover cost with energy arbitrage it would create perverse incentives for transmission investors to exploit existing interregional congestion for their own profit. For instance, this can be done by developing a transmission line with a small enough capacity to where it does not significantly relieve the congestion but rather optimizes their economic returns. However, an evaluation of comprehensive multi-value benefits would inform the transmission planners that such a transmission design is not configured for optimal benefit-to-cost for transmission customers. This is where the importance of aligning comprehensive multi-value planning with the merchant transmission investment model becomes clear. Thus, the merchant-based cost-recovery viability of a transmission project must be considered in tandem with multi-value benefits.

5.2 Capacity Contract Module Insights

Similar to the energy arbitrage analysis, capacity contract analysis results are informative of critical components of multi-value benefits, and additional projects under study were demonstrated to be business viable. Still, the production cost savings and generation capital cost reduction consideration were not sufficient to show that each project is a more economical option relative to its respective local alternative. Again, the merchant investor must use the multi-value benefits framework to accurately evaluate the comprehensive value of a transmission project and then capture this value to make the capacity contract cost-recovery mechanism business viable for all projects. It is insightful to review the qualitative effects of the modeling assumptions on the multi-value benefits evaluation and subsequent cost recovery analysis.

5.2.1 Evaluating Multi-value Benefits with Capacity Contract Analysis

Compared to the energy arbitrage analysis, the capacity contract analysis used a more refined approach to capturing production cost savings. The analysis attempts to justify the renewable energy generation and transmission PPA price by comparing this price to the local alternative renewable energy generation PPA price. The difference in PPA price between the energy generation and transmission and local alternative is effectively the production cost savings value, but with the current modeling approach, this value is not positive for each project. It is important to note that this shortcoming can be due to the single-directional power flow model assumption. This assumption effectively limits the transmission line utilization and hence revenue generation. Expanding the model to consider bi-directional power flow for capacity contracts would have required time-series energy consumption data sources that are not readily accessible and modeling that is beyond the scope of this analysis.

The additional transmission benefit consideration added was the generator capital cost benefit in the form of a hypothetical RPS target constraint. In a straightforward subsequent analysis, the local alternative for renewable energy generation was tasked to match the annual energy demand satisfied by renewable energy generation delivered by the transmission project under study. Once accounting for this, additional projects yielded positive production cost savings and appeared as an economically viable option for the potential offtaker.

This additional transmission benefit consideration approach can be generally applied to the other multi-value benefit categories. Similar to the energy arbitrage analysis, the limiting factor is the required data sources and extensive modeling of existing electric grid infrastructure including generators, market operations, and transmission contingency occurrences. Nevertheless, the results of the energy arbitrage and capacity contract analysis strike a fitting balance of complexity and flexibility to enable computational reduction across a variety of projects. The results are indicative of the multi-value benefits of the transmission lines under study and provide insights that support guided focus for subsequent comprehensive multi-value analysis.

5.2.2 Capacity Contract Cost Recovery Insights

Despite the capacity contract analysis improvements over energy arbitrage for cost recovery viability, it is clear that additional value must still be considered for long-range and capital-intensive projects. The selling points for the projects under study are not just the access to low-cost and renewable energy. It is also the congestion relief across regions, access to diversified energy resources, and improvements in reliability and resilience. Once framed according to the transmission multi-value benefit categories that reflect this selling point, the projects under study look significantly more attractive to potential off-takers at their PPA price, and cost recovery can be essentially ensured once the contract is signed. Identical to the energy arbitrage cost recovery discussion, the results of the capacity contract analysis show that the multi-value benefits of the transmission projects are important, and the projects need to incorporate the evaluated comprehensive value for cost-recovery viability.

5.3 Future Energy Arbitrage and Capacity Contract Module Improvements with Synthetic Grid Modeling

Modeling the physics-based, electric power flow and behavior of the actual electric grid would enable TBET to expand its functionality and better evaluate the power flow performance of the transmission projects under study. As the term implies, synthetic electric grids are synthetic transmission and distribution networks that are built to match the statistical electric characteristics of the actual electric grid, and importantly, they are publicly accessible because they are free from confidential requirements such as FERC protected Critical Energy/Electric Infrastructure Information (CEII) [7]. They are typically developed by academic and technical institutes to aid power systems research and development. Birchfield et al., from Texas A&M University, have developed a repository of synthetic electric grids of various RTO/ISO regions and larger synchronous transmission interconnects. Furthermore, this team has developed a methodology to augment the synthetic network base case for economic dispatch simulations informed by actual grid generator cost models and LMPs [55]. Therefore, with the use of synthetic electrical grids and MATPOWER, an open-source tool for electric power system simulation and optimization, the energy arbitrage and capacity contract module analysis can be expanded to conduct bi-directional power flow analysis and measure the capabilities of the transmission projects under study in various scenarios. Moreover, the economic dispatch methodologies can allow the energy arbitrage module to expand beyond the price-taker model and base-case assumptions.

Synthetic electric grid power flow analysis can be conducted for the energy arbitrage and capacity contract modules by modeling existing or future generator mix, electricity demand, and transmission line specifications of the projects under study. For instance, an existing synthetic electric grid can be modified to include a transmission project under study and pertinent generator and load updates at the POR and POD electrical buses that connect to the transmission line. In the simplest case, this process entails finding the appropriate electrical bus in the synthetic grid model that represents the geographic POR and POD for the project under study, adding increased power generation at the POR bus and increased power consumption at the POD bus, then adding the project's transmission line with included specifications as a connection between the POR and POD buses. Specific to the energy arbitrage module, the POR and POD bus power generation, and consumption will reflect one snapshot in time that represents a typical case of peak and off-peak actual power generation and consumption market activity. Specific to the capacity contract module, the generator at the POR will be updated to reflect the added renewable energy generation profile that is bundled in the generation and transmission PPA. In addition, the single-directional power flow assumption will be removed and bi-directional power flow capabilities will be enabled. Finally, MATPOWER will be used to conduct the power flow analysis and explore results.

The synthetic grid economic dispatch methodology can be added to the energy arbitrage module's capabilities to analyze LMP sensitivity analysis. This added capability will expand beyond basic price-taker model assumptions by analyzing how the LMPs at the POR and POD buses change when the transmission line of the project under study is added across various scenarios. The process would effectively simulate a single PCM run that represents the updated generation requirement at the POR, consumption requirement at the POD, and the added transmission line. More specifically, MATPOWER would conduct DC OPF with the updated synthetic grid model along with the generator cost models and consumption models. The DC OPF will yield the updated LMPs at the POR and POD buses. This process can be replicated under a variety of different time-of-day and time-of-year scenarios to emulate diurnal and seasonal patterns that are exhibited in real-world LMPs. However, this process may become computationally demanding and time-consuming, so an alternative approach is to run just a peak and off-peak hour case and calculate the percentage change of the LMP values for each case. Finally, the LMP percent change can be used to uniformly modify the initial input LMPs, and then the updated price-taker model can be used for more informed energy arbitrage analysis. This single PCM run followed by an updated price-taker model analysis reflects the computation-reduced approach identified by Martinek et al., in their comparison of price-taker models and PCMs [43].

Appendix A

TBET Module Flowcharts

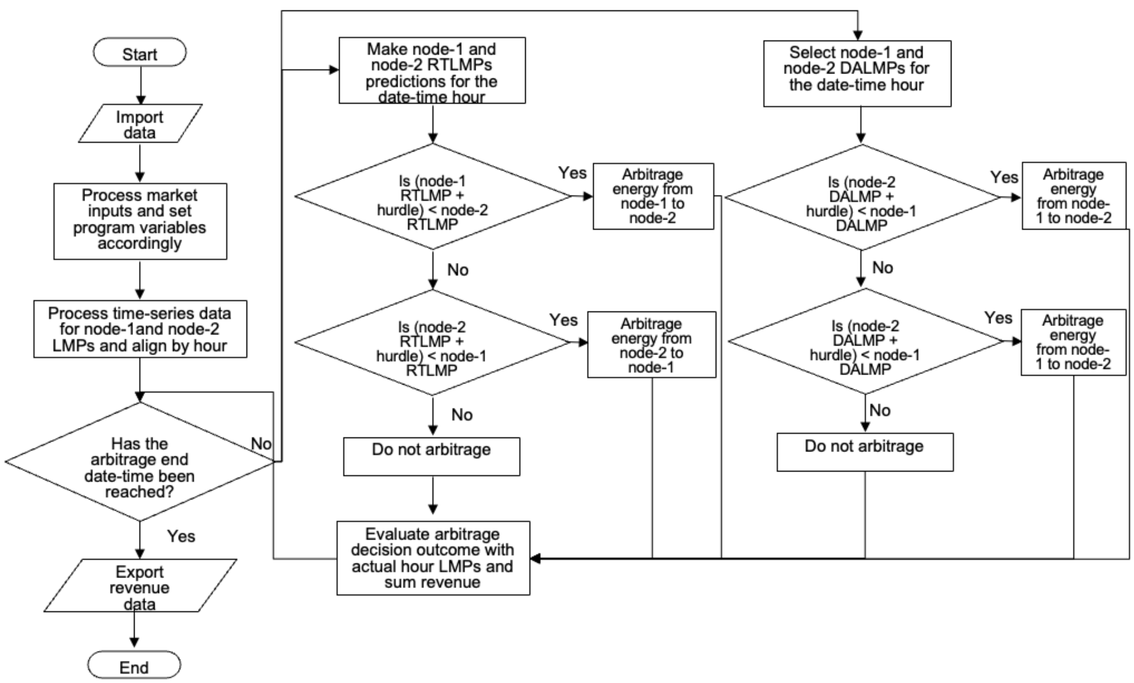

Figure A-1: TBET Energy Arbitrage Analysis Flowchart

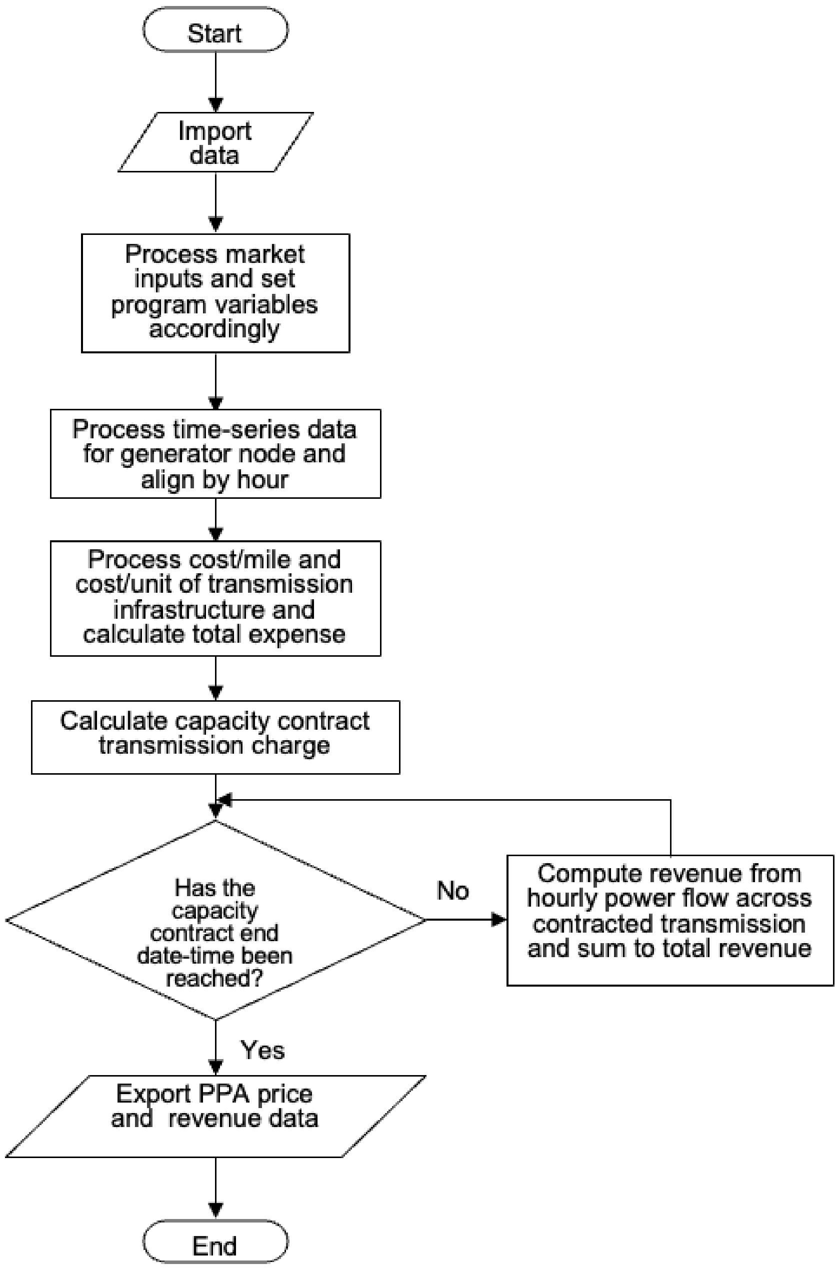

Figure A-2: TBET Capacity Contract TBET Analysis Flowchart

Appendix B

TBET Capacity Contract Results

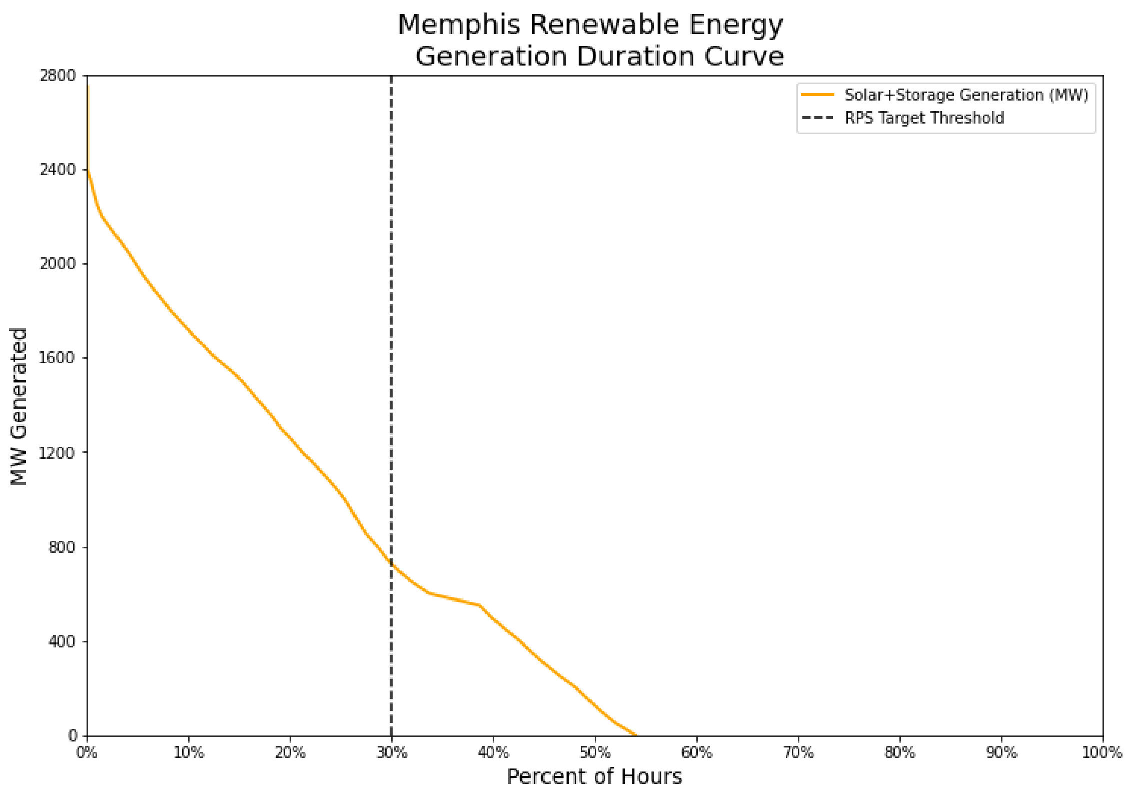

Figure B-1: Plains and Eastern Load Region Equalized Power Generation for RPS 30% Target Duration Curve

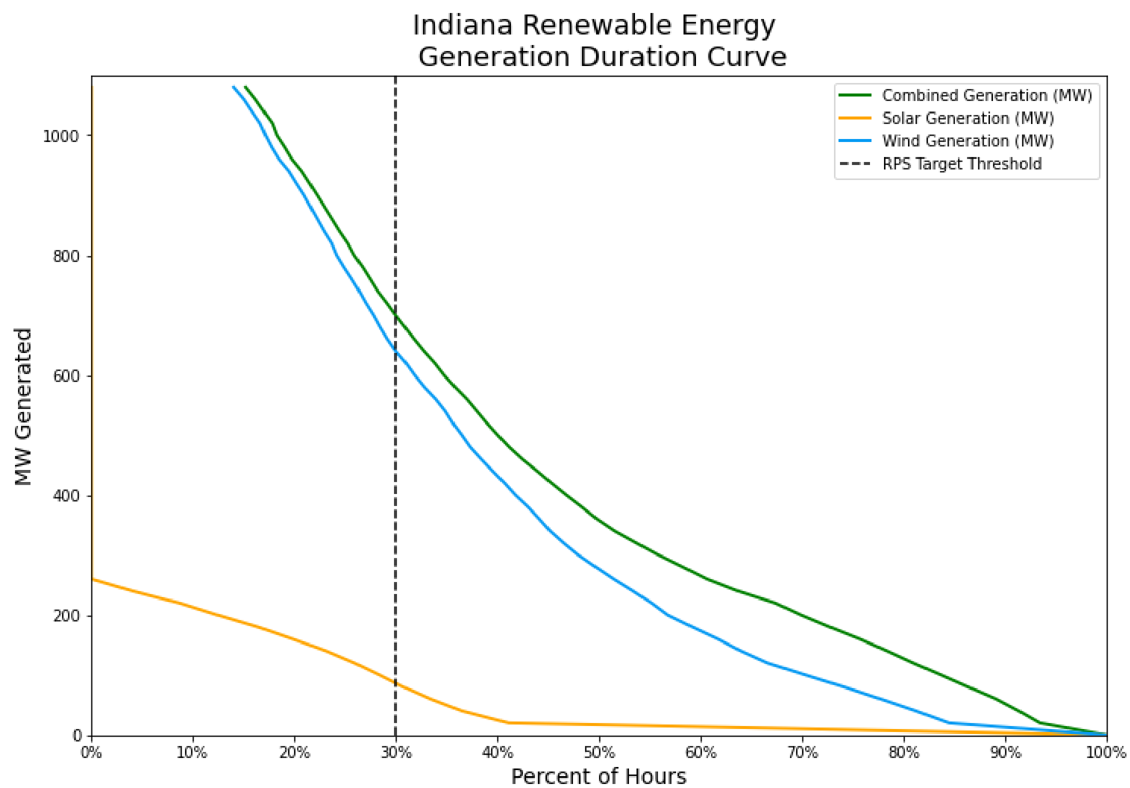

Figure B-2: Grain Belt Express Load Region Equalized Power Generation for RPS 30% Target Duration Curve

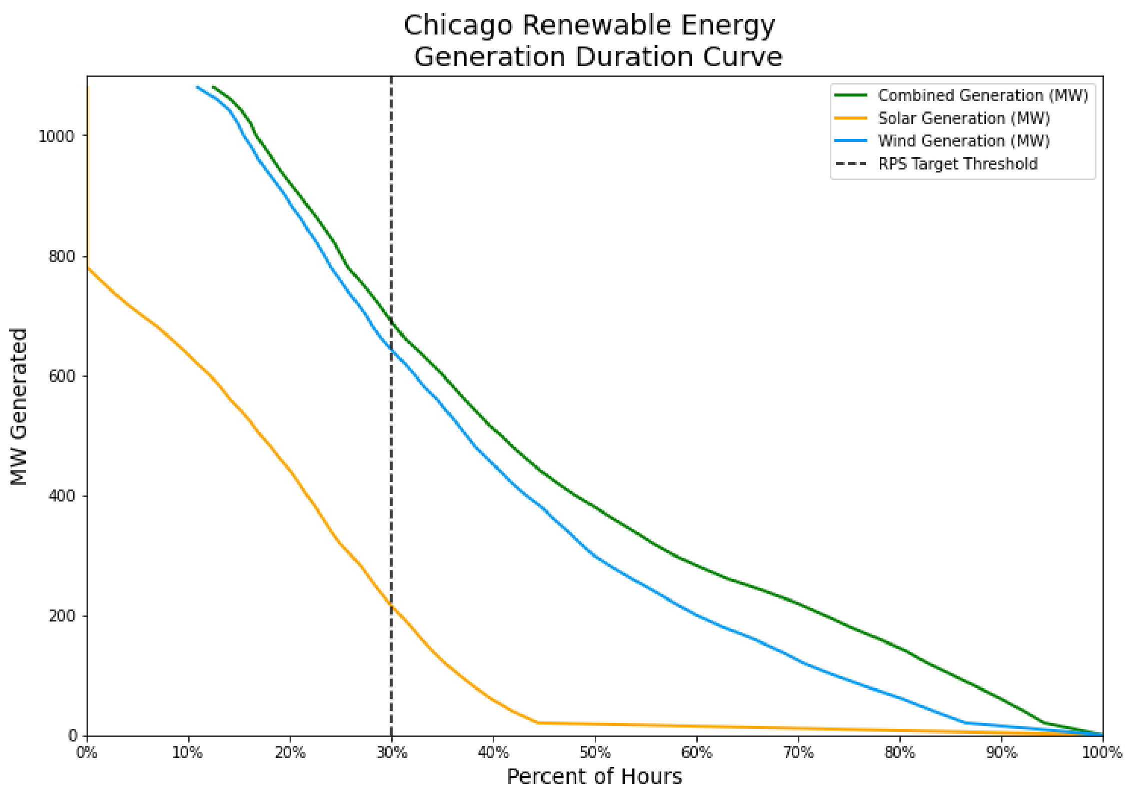

Figure B-3: SOO Green Load Region Equalized Power Generation for RPS 30% Target Duration Curve

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