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Table of Contents

List of Tables v
List of Figures vii
List of Abbreviations x
1.0 Executive Summary 1
2.0 Conceptual Study 2
2.1 Introduction 2
2.1.1 Process Description 2
2.2 Technology Readiness Level 5
2.2.1 Technology Status 5
2.2.2 Commercial Application 7
2.3 Conceptual Study Steps 9
2.3.1 Selected site for the conceptual study analysis 10
2.3.2 Scenarios to be analyzed 13
2.3.3 Economic Analysis Methodology 15
2.3.3.1 Scenario 1 – Flue Gas Charging of TES 25
2.3.3.2 Scenario 2 – Hybrid Charging of TES, Flue Gas with Electrical Topping 32
2.3.3.3 Scenario 3 – Electrical Charging of TES 38
2.3.3.4 Scenario 4 – Hybrid Charging of TES, Steam with Electrical Topping 44
2.3.4 Non-Financial Benefits 50
2.3.5 Scenarios Comparison Summary 51
2.4 Post-Project Plans 53
2.5 References 54
2.6 Appendix – Technology Readiness Levels Defined by DOE 55
2.7 Appendix – Value Sensitivity to Storage Duration 57
2.8 Appendix – Zeltmann Historical Generation 60
3.0 Techno-Economic Assessment 61
3.1 Introduction 61
3.1.1 Process Description 63
3.2 Design and Cost Basis 64
3.2.1 Design Basis 64
3.2.1.1 Site Characteristics 64
3.2.1.2 Storage Capacity 66

3.2.1.3 Sources of Charging Energy 66
3.2.1.4 Charge and Discharge Durations 67
3.2.1.5 Hybrid Charging Assumptions 67
3.2.2 Cost Estimate Basis 67
3.2.2.1 Cost Estimate Methodology 67
3.2.2.2 Energy Storage System 67
3.2.2.3 Balance of Plant Facilities 68
3.3 Performance summary 70
3.4 Cost estimates 71
3.4.1 Capital Costs 71
3.4.2 Operating and Maintenance Costs 74
3.5 Economic analysis 74
3.5.1 Benefits and Potential Income Streams 74
3.5.2 Overall Cash Flow Analysis 75
3.5.3 Economic Assessment 77
4.0 Technology Gap Assessment 78
4.1 Current State of the Brenmiller Thermal Storage Technology 78
4.2 Future Target for Brenmiller TES Deployment 78
4.2.1 Industrial Scale 79
4.2.2 Utility Scale 83
4.3 Technology Gaps 83
4.3.1 Industrial Scale 83
4.3.2 Utility Scale 85
4.3.3 Potential Risks from Operational Externalities 87
4.4 Plan to Address Identified Gaps 87
4.5 References 88
5.0 Commercialization Plan 89
5.1 Executive Summary 89
5.2 Commercialization Plan 89
5.2.1 Market Drivers 89
5.2.1.1 Renewables Penetration 89
5.2.1.2 Required flexibility for market competitivness 90
5.2.1.3 Increasing Carbon Tax and Prices 91
5.2.1.4 Increasing Market Support for Energy Storage 95
5.2.2 United States Market 97

5.2.3 Global Markets 97
5.2.4 Technology Advantages 100
5.2.5 Competition 103
5.2.5.1 Comparison 103
5.2.5.2 Techno-economics Calculation 105
6.0 Technology Maturation Plan 111
6.1 Introduction 111
6.1.1 Process Description 111
6.2 Technology Readiness Level 114
6.2.1 Technology Status 114
6.2.2 Commercial Application 117
6.3 Proposed Work 119
6.3.1 Objectives of Current Project 124
6.3.2 Project Specific Attributes 124
6.3.3 Key Metrics 126
6.4 Post-Project Plans 126
6.5 References 127
6.6 Appendix – Technology Readiness Levels Defined by DOE 128
7.0 Acknowledgement and Disclaimer 130

List of Tables

Table 2-1. Status of other projects undertaken by Brenmiller Energy 7
Table 2-2. Zeltmann Plant Generation – Power (KW) 13
Table 2-3. Selected Scenarios for Analysis.. 15
Table 2-4. Maximum Theoretical Energy Arbitrage Margin for a 1MW system based on actual historical prices at the Zeltmann node (no operational constraints) $/KW-month... 16
Table 2-5. Real-Time Market Results: Theoretical limit on Real Time Arbitrage with no limitations (hourly data) vs 24 hour and 4-hour storage duration under the stylized algorithm tested with efficiency limitations (no plant capacity factor limitations) 20
Table 2-6. Day-Ahead Market Results: Theoretical limit or Day Ahead Arbitrage with no limitations vs 24 hour and 4-hour storage duration under the stylized algorithm tested with efficiency limitations (no plant capacity factor limitations)...................... 21
Table 2-7. Carbon price simulation results 24
Table 2-8. Key Charging and Discharging Energy Flows 28
Table 2-9. Potential Energy Arbitrage and Capacity Value of bGenTM Storage 29
Table 2-10. Required Investment for Scenario #1 29
Table 2-11. Project IRR - Scenario #1 - Source of charging energy: CT Exhaust gas 1040F.......... 30
Table 2-12. Cash Flow Analysis – Scenario #1 31
Table 2-13. Key Charging and Discharging Energy Flows 34
Table 2-14. Potential Energy Arbitrage and Capacity Value of bGen™ Storage 35
Table 2-15. Required Investment for Scenario #2 36
Table 2-16. Project IRR – Scenario #2 - Source of charging energy: Hybrid Charging................. 36
Table 2-17. Cash Flow Analysis – Scenario #2 37
Table 2-18. Potential Energy Arbitrage and Capacity Value of bGen™ Storage 41
Table 2-19. Required Investment for Scenario #3 41
Table 2-20. Project IRR – Scenario #3 – Source of charging energy: Local or Grid Electricity...... 42
Table 2-21.Cash Flow Analysis – Scenario #3 43
Table 2-22. Potential Energy Arbitrage and Capacity Value of bGen™ Storage 48
Table 2-23. Required Investment for Scenario #3 48

Table 2-24. Project IRR – Scenario #4 – Source of charging energy: Steam and Electricity......... 49
Table 2-25.Cash Flow Analysis – Scenario #4 50
Table 2-26. Technology Readiness Level Definitions.. 55
Table 2-27. Energy Arbitrage Gross Margin and Implied Present Value (PV) over a 25 year period – Real Time prices on hourly terms (average 2015 – 2021).............................. 57
Table 2-28. Energy Arbitrage Gross Margin and implied present value (PV) over a 25 year period– Day Ahead Prices (Average 2015-2021)... 58
Table 2-29. Historical Generation at Zeltmann Power Plant.. 60
Table 3-1. Capital Cost Summary for Scenario #4 71
Table 3-2. bGen™ Storage System Cost Breakdown.. 71
Table 3-3. Scenario #4 - Balance of Plant Cost Estimate 72
Table 3-4. Scenario #4 - Balance of Plant Equipment List 73
Table 3-5. Potential Energy Arbitrage and Capacity Value of bGen™ Storage 75
Table 3-6. Project IRR – Scenario #4 – Source of charging energy: Steam and Electricity.......... 76
Table 3-7. Scenario #4 - Cash Flow Analysis 77
Table 4-1. Status of other projects undertaken by Brenmiller Energy... 79
Table 5-1. Carbon Emissions Statistics, Europe 2011 – 2019 (Millions of tons CO2).................. 93
Table 5-2. Carbon Price Simulation Results.. 94
Table 5-3. Industrial Segment Energy Storage Comparison 104
Table 5-4. Utility Power Segment Energy Storage Comparison 105
Table 5-5. Capital Cost Summary for Scenario 4 – Hybrid Charging... 107
Table 5-6. Potential Energy Arbitrage and Capacity Value of bGenTM Storage 108
Table 5-7. Project IRR – Scenario #4 – Source of charging energy: Hybrid Steam and Electricity.. 109
Table 5-8. Scenario 4 - Cash Flow Analysis for Scenario 4 110
Table 6-1. Status of other projects undertaken by Brenmiller Energy....................................... 116
Table 6-2. Prior Development Activities, Milestones and Results.. 120
Table 6-3. Representative example of performance parameters 124
Table 6-4. Technology Readiness Level Definitions.. 128

List of Figures

Figure 2-1. Flexible charging and discharging options........ 3
Figure 2-2. Artist's rendering of a Brenmiller Energy bGen™ thermal storage module........ 3
Figure 2-3. Photo of a Brenmiller Energy bGen™ thermal storage module internals (bCubes)........ 4
Figure 2-4. bGen™ module stacking of bCubes........ 4
Figure 2-5. Brenmiller Energy bGen™ pressures, temperatures, and flow rate during an 8-hour discharge cycle........ 5
Figure 2-6. Brenmiller Energy bGen™ as planned for integration with NYPA........ 6
Figure 2-7. Thermal Charging of TES........ 8
Figure 2-8. Electrical Charging of TES........ 8
Figure 2-9. Steam Discharging from TES........ 9
Figure 2-10. Zeltmann Plant – Queens, NY, Arial Photograph........ 10
Figure 2-11. Zeltmann Plant – New York City........ 11
Figure 2-12. Zeltmann Plant – Site Plan........ 12
Figure 2-13. Zeltmann Plant - Mechanical Arrangement - Prepared Tank Location........ 12
Figure 2-14. Zeltmann Node Energy Price Probability Distribution – 2017 example........ 17
Figure 2-15. Zeltmann 2020 & 2021 Average Prices........ 18
Figure 2-16. New York ISO Graphic on Recent Capacity Market Clearing Prices........ 22
Figure 2-17. Scenario #1 – Flue Gas Charging........ 25
Figure 2-18. Scenario #1 – Flue Gas - Charging Heat Balance........ 26
Figure 2-19. Scenario #1 - Discharge Mode – Heat Balance........ 27
Figure 2-20. Scenario #1 –PFD........ 28
Figure 2-21. Scenario #2 – Hybrid Charging........ 32
Figure 2-22. Scenario #2 – Hybrid Charging – Heat Balance........ 33
Figure 2-23. Scenario #2 – PFD........ 34
Figure 2-24. Scenario #3 – Electrical Charging........ 38
Figure 2-25. Scenario #3 – Electrical Charging – Heat Balance........ 39
Figure 2-26. Scenario #3 – Balance of Plant PFD........ 40
Figure 2-27. Scenario #4 – Hybrid Charging, Steam + Electricity........ 44

Figure 2-28. Scenario #4 – Steam Hybrid Charging – Heat Balance 46
Figure 2-29. Scenario #4 –PFD 47
Figure 2-30. bGenTM Installation at Zeltmann – Predicted Revenue Sources............................ 52
Figure 2-31. Present Value to Storage Size Charts. Real Time (Hourly Prices at Astoria CC 1 node) – Average Gross Margins 2015 - 2021.. 58
Figure 2-32. Day Ahead Prices (Average Gross Margins 2015 – 2021)....................................... 59
Figure 3-1. Scenario #4 -Hybrid Charging, Steam + Electricity 62
Figure 3-2. Heat Balance Diagram - Scenario #4 Hybrid Steam/Electric Charging....................... 64
Figure 3-3. Zeltmann Plant – Queens, NY, Arial Photograph.. 65
Figure 3-4. Zeltmann Plant – Site Plan.. 66
Figure 3-5. Process Flow Diagram - Scenario #4 Hybrid Steam/Electric Charging 70
Figure 3-6. bGen™ Installation at Zeltmann – Predicted Revenue Sources 75
Figure 4-1. bGen™ charging and discharging options 78
Figure 4-2. Industrial scale application 80
Figure 4-3. SUNY Purchase in New York, USA – 400kW/450kWh 80
Figure 4-4. bCube™ modular approach to scaling to 100s of MWh.. 81
Figure 4-5. Stacking Arrangement Design 82
Figure 4-6. Construction of Foundation for Stacking Arrangement 82
Figure 4-7. Stacking Approach for Utility Scale Installations.. 86
Figure 5-1. Annual Electricity Generating Capacity Additions and Retirements (AEO2021 Reference Case) 90
Figure 5-2. European System of Carbon Allowances trading, Liptzig, Germany 92
Figure 5-3. Global Cumulative Energy Storage Installations (2015-2030)................................... 95
Figure 5-4. Projected Cumulative US Grid-Related Deployment by Application (2015-2022)..... 96
Figure 5-5. Quarterly average wholesale prices for selected regions (2016-2021). Source: IEA, "Electricity Market Report January 2022", 2022... 98
Figure 5-6. Value Snapshot of International Case Studies (Lazard, 2021).................................. 99
Figure 5-7. IEA's Projection of Electricity Generation Types 99
Figure 5-8. Gas-fired power generation capacity additions by region, 2020-2022. Source: IEA, 2021 100
Figure 5-9. Flexible charging and discharging options for bGen™ 101

Figure 5-10. Hybrid Charging (Scenario 4) ... 102
Figure 6-1. Flexible charging and discharging options... 111
Figure 6-2. Artist's rendering of a Brenmiller Energy bGen™ thermal storage module... 112
Figure 6-3. Photo of a Brenmiller Energy bGen™ thermal storage module internals (bCubes) ... 113
Figure 6-4. Containerized bGen™ thermal storage module ... 113
Figure 6-5. Brenmiller Energy bGen™ pressures, temperatures, and flow rate during an 8-hour discharge cycle ... 115
Figure 6-6. Brenmiller Energy bGen™ as planned for integration with NYPA ... 116
Figure 6-7. Thermal Charging of TES... 117
Figure 6-8. Electrical Charging of TES ... 118
Figure 6-9. Steam Discharging from TES... 118
Figure 6-10. Potential Process Diagram for bGen™ Technology Integration with NGCC Power Plant... 125

List of Abbreviations

BOP	Balance of Plant
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat & Power
CSP	Concentrated Solar Power
CT	Combustion Turbine
DA	Day Ahead
DOE	Department of Energy
EPRI	Electric Power Research Institute
E&C	Engineering and Construction
FEED	Front End Engineering Design
FTM	Front of the Meter
H&MB	Heat and Material Balance
HRSG	Heat Recovery Steam Generator
HTF	High Temperature Fluid
IDF	Israel Defense Forces
IRR	Internal Rate of Return
MTBF	Mean Time Between Failure
MTTR	Mean Time to Repair
NETL	National Energy Technology Laboratory
NGCC	Natural Gas Combined Cycle
NYPA	New York Power Authority
P&ID	Piping and Instrumentation Diagrams
PFD	Process Flow Diagram
PMP	Project Management Plan
RFP	Request for Proposal
RTE	Round Trip Efficiency
SOPO	Statement of Project Objectives
ST	Steam Turbine
STG	Steam Turbine Generator
TES	Thermal Energy Storage
VRE	Variable Renewable Energy

1.0 EXECUTIVE SUMMARY

The goal of this project was to design a next-step pilot to advance near-term energy storage integrated with a fossil plant to provide a facility capable of being viable and effective in a market with growing penetration of variable renewable energy (VRE). Thermal energy storage (TES) represents an ideal technology for this purpose. The completed effort included a feasibility study to prepare for the Phase II pre-front end engineering design (pre-FEED) for implementing a crushed-rock TES system integrated with a natural gas combined cycle (NGCC) plant. The crushed rock storage technology, which is being developed by Brenmiller Energy, is a modular TES system termed bGen™, which can accommodate both thermal and electrical inputs and output steam, hot water, or hot air. For this application, the estimated efficiency is 80% thermal to thermal.

For the feasibility study, the Brenmiller technology was designed to operate on a slipstream from NYPA's Eugene W. Zeltmann Power Project (Zeltmann) NGCC plant in Astoria, New York. The projected size of the system will be up to 4 MWe with at least 4 hours of storage duration, or 16 MWh-e total. The study also included a techno-economic evaluation of a 200 MWh commercial-scale demonstration. Prior to this project, EPRI had reviewed Brenmiller's technology, which is being built to demonstrate bGen™ at 1.7 MWe on a solar plant (Rotem) and has been designed for an NGCC facility in Italy, assessing it at technology readiness level (TRL) 5. Brenmiller is also conducting a separate 1-MWth pilot with NYPA that pairs a bGen™ module with a microturbine for a combined-heat-and-power (CHP) application to improve efficiency and provide flexibility.

The next-step pilot being designed as part of this project would represent a 5-fold increase in scale, versus Rotem, and would show the technology's ability to provide effective and economical energy storage, bringing the technology to TRL 6. This pilot would represent the next-to-last demonstration scale before the technology could be commercial ready at GWh-e scales in the 2030 timeframe.

The main objective of the work completed by the Electric Power Research Institute, Inc. (EPRI), Brenmiller Energy (Brenmiller), New York Power Authority (NYPA), and United E&C (formerly AECOM) was to perform a Phase I feasibility study on the integration of a crushed-rock thermal energy storage (TES) with a fossil plant. Under this project, the EPRI-led team successfully completed a feasibility study to prepare for the potential future Phase II pre-front end engineering design (pre-FEED) to implement a crushed-rock TES system integrated with a natural gas combined cycle (NGCC) plant. Specific deliverables under this project included the Technology Maturation Plan, Conceptual Study, Techno-Economic Assessment, Technology Gap Assessment, Project Plan for Phase II (submitted as Phase II Renewal Application), Commercialization Plan, and the Final Report (this document).

This Final Report includes a compilation of the various summary reports that were prepared during the 12-month schedule of the Phase I project execution under award DE-FE0032017.

2.0 CONCEPTUAL STUDY

2.1 Introduction

Brenmiller Energy of Rosh HaAyin, Israel, has developed a modular, containerized thermal energy storage (TES) system, known as bGen^{TM}, capable of accommodating both thermal and electrical inputs and generating steam or hot water. The storage medium is crushed rock, which is selected for specific properties conducive to economical sensible heat storage. This TES system has been developed by Brenmiller Energy over the last 8 years and has been tested in 3 generations of demonstration units at various sites, globally. Brenmiller Energy expects a bGen^{TM} module will have a 30-year life without any replacement of the storage media. The bGen^{TM} modules are configured in a manner that allows interconnection both vertically (i.e., in a stack) and horizontally to build systems ranging in thermal capacity from 0.5 MW-thermal to 1.0 GW-thermal. The modules' operation is configurable, so the thermal or electrical input runs through all or some of the modules during charging or discharging. Targeted applications of this crushed rock TES system include renewables integration and grid support; decoupling of the time of electricity and thermal energy supply in combined heat and power (CHP) systems; power-to-heat applications where there are sharp swings in the cost of electricity from off-peak to peak; and the ability to independently operate the gas turbine and steam turbine for flexible power generation in natural gas combined cycle (NGCC) plants.

2.1.1 Process Description

The bGen^{TM} technology, is a modular crushed-rock TES system that can be charged from both thermal and electrical inputs, and can output steam, hot water, or hot air, as shown in Figure 2-1. Power is indicated as an output of the system as the bGen^{TM} can produce superheated steam which directly activates a steam turbine. Charging of a module is accomplished by electrical resistance heating, or by a fluid (e.g. heated oil, steam, hot water, or hot flue gases) flowing through tubing set among the crushed rock. There is no direct contact between a charging fluid and the crushed rock. Figure 2-2 shows a representative module, without the exterior container.

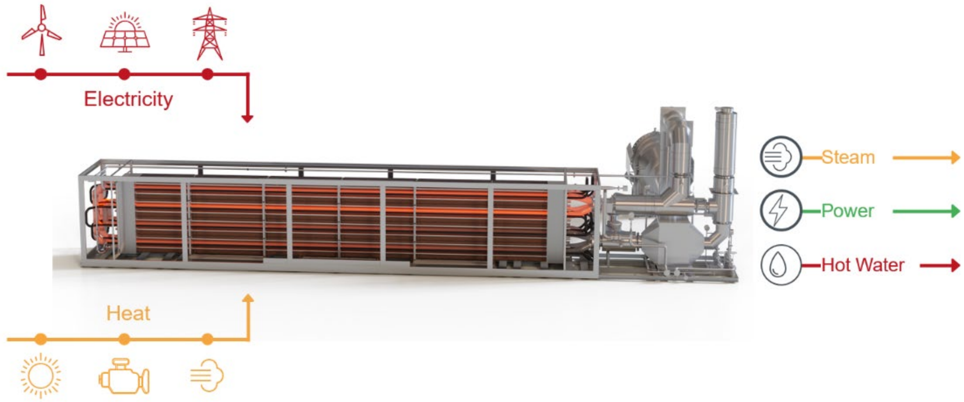


Figure 2-1. Flexible charging and discharging options

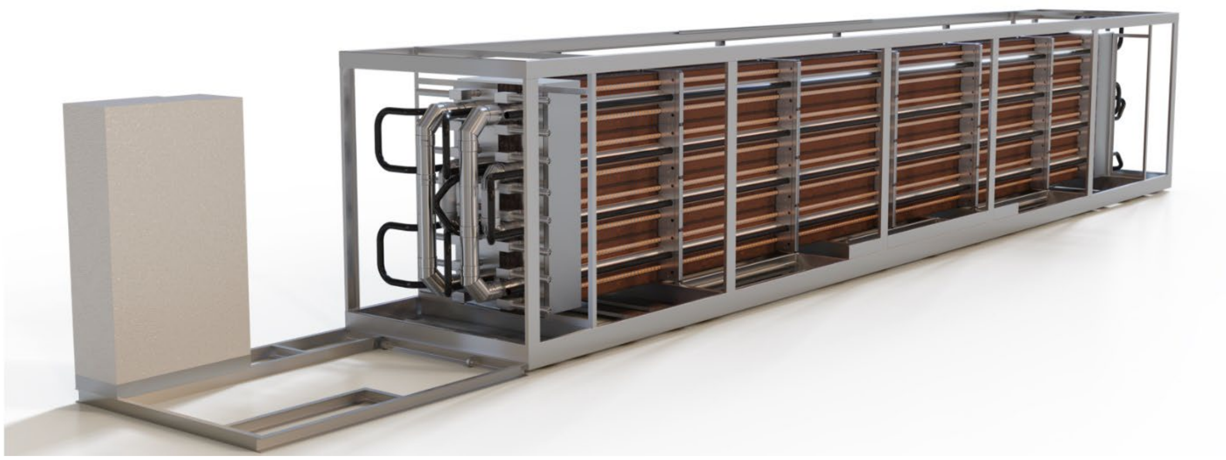


Figure 2-2. Artist's rendering of a Brenmiller Energy bGen^{TM} thermal storage module

The main patented technology includes a high temperature energy storage system based on crushed rocks, which combines three elements: a heat exchanger, thermal storage and a steam generator. The bGen^{TM} unit requires minimal maintenance and no media replacement for 30 years. The typical output capacity for a bGen^{TM} module in a power generation application will be about 2 MW-th. The storage medium is selected for properties conducive to economical sensible heat storage. The target installed cost of the TES system is projected to be less than \$50 /kW-th. The unit is built from multiple separate units called bCubes, each enabling the exchange of heat, converting electricity to heat and producing steam. Each bCube is about 20 in. (0.5 m) square by 40 ft (12 m) long. The bCubes are visible in Figure 2-3. Each bCube contains horizontal and vertical tubes for effective heat transfer and interconnecting piping that supports stacking and horizontal interconnection of multiple bGen^{TM} modules. These bCubes are assembled into bGen^{TM} module, which is a result of stacking bCubes horizontally and vertically, as shown in Figure 2-4. bCubes are designed to fit in a standard 40-ft (12 m) shipping container. The modules can accommodate charging fluid temperatures up to 1300°F (700°C), but for temperatures above 1050°F (565°C), special high-temperature alloy tubing is needed. If flue gas is the charging fluid, corrosion-resistant tubing is used if the exit gas temperature will be at or below the dew point.

Figure 2-3. Photo of a Brenmiller Energy bGen™ thermal storage module internals (bCubes)

Figure 2-4. bGen™ module stacking of bCubes

2.2 Technology Readiness Level

The Brenmiller Energy bGen™ crushed rock TES system has been evaluated to assess the Technology Readiness Levels (TRL), using the criteria defined by the U.S. Department of Energy, as shown in the Appendix (see Table 2-26). The evaluation of current TRL score includes a review of prior development work, as well as other simultaneous supporting activity. The assessment of TRL score at the end of the proposed work scope is based upon the assumption of a successful outcome of the proposed effort.

2.2.1 Technology Status

Brenmiller Energy has a working proof-of-concept for the storage system, which has been tested, verified, and validated at the Rotem demonstration site in the south of Israel. This test rig demonstrated the ability to operate the bGen™ system for a prolonged amount of time and to achieve performance goals. In this test, the salient performance parameters were stable production of superheated steam at high temperature and pressure, storage heat capacity, storage discharging rate, overall storage heat transfer coefficient, and low storage heat loss.

As of September 2018, the demonstration has shown a prolonged steady production of steam, for a duration of 8 hours, at temperatures up to 970°F (521°C) and at a pressure of about 1160 psig (80 barg), as shown in Figure 2-5. The brief pressure dip seen in the graph is related to startup of the discharge cycle when pressure builds up from 0 to 1160 psig (0 to 80 barg). The steam is delivered to users at the end of the startup stage when it reaches operating conditions.

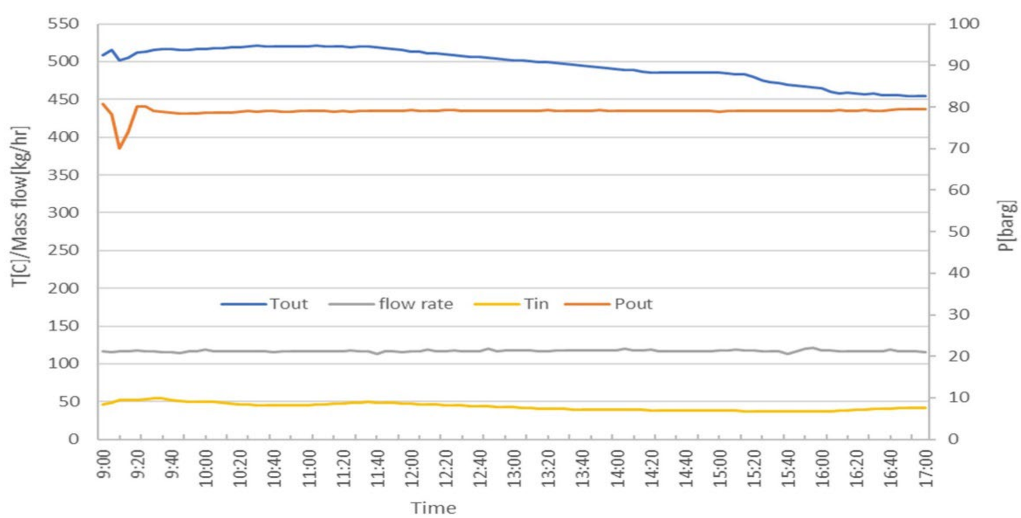


Figure 2-5. Brenmiller Energy bGen™ pressures, temperatures, and flow rate during an 8-hour discharge cycle

Brenmiller Energy is supplying its energy storage technology at 1.7-MWe scale as part of the Rotem 1 Concentrated Solar Power (CSP) in the Negev desert, which is scheduled to begin grid-connected operation in 2022. The addition of storage will allow the plant to generate electricity for up to 16 hours per day. Potential addition of natural gas could allow the unit to operate up to 24 hours per day. A successful demonstration will allow bGen^{TM} technology to achieve a technology readiness level (TRL) of 9 at this small scale, as Rotem 1 is a commercial project with a 20-year power purchase agreement with the Israel Electric Corporation. Relative to the ultimate utility scale of hundreds of MWhe, bGen^{TM} technology will be at a TRL of 6 following successful operation at Rotem 1.

Separately, Brenmiller Energy is conducting a pilot project with the New York Power Authority (NYPA) at 400-KWth scale that pairs a bGen^{TM} TES module with a microturbine in a CHP application to improve energy efficiency and provide flexibility in extreme conditions on a State University of New York campus, including operation independent of the grid [2, 3, 4]. Startup is scheduled for Q1-2022. A 3D rendering of the TES system to be used for the CHP integration is shown in Figure 2-6.

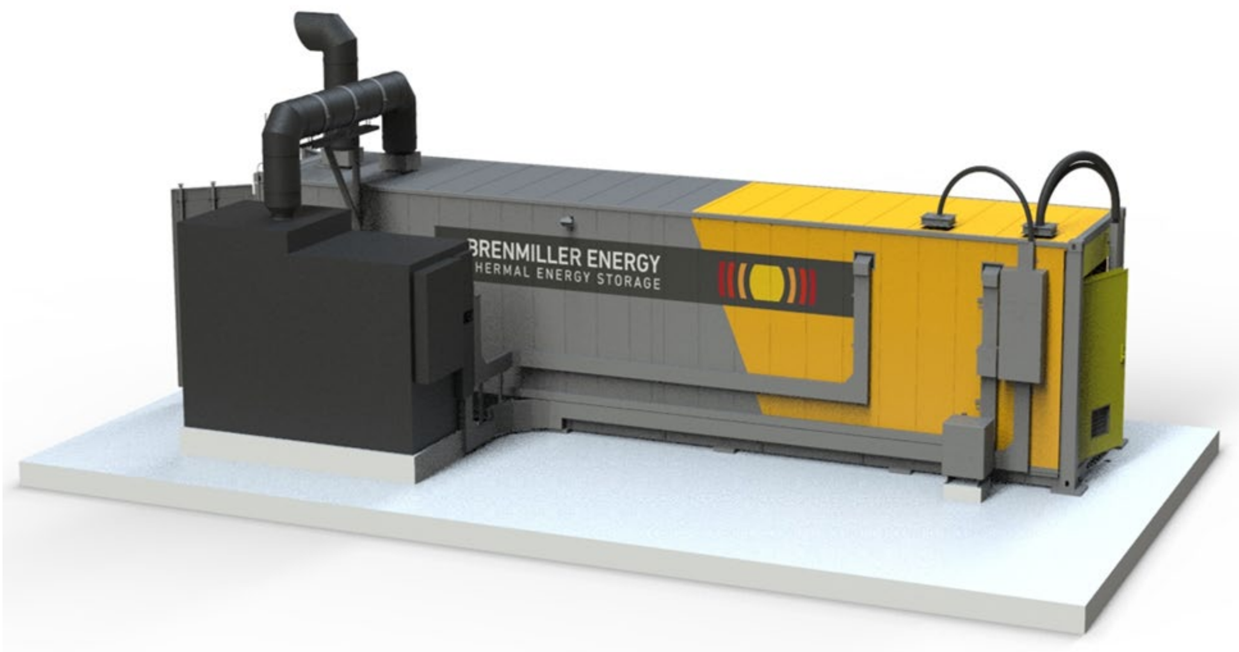


Figure 2-6. Brenmiller Energy bGen^{TM} as planned for integration with NYPA

Table 2-1 details various development projects by Brenmiller Energy, and their corresponding status. These projects are built at prototype scales for various market segments, such as the industrial segment for medium to high temperatures, the power utility segment, and the CHP commercial segments. Final installation and commissioning of each of these prototypes is intended to advance the technology readiness for each of the related segments, utilizing the core technology of the bGen™ system.

Table 2-1. Status of other projects undertaken by Brenmiller Energy

Site / Customer	Market Segment	Development Stage	Power	Capacity	Planning	FEED	Construction	Commiss-ioning	Operations
ENEL Italy	Power Utility	Commercial Pilot	5MW	24MWh	Completed	Completed	Sep 2021 – Nov-21	Dec 2021 – Mar-22	2022
FORTLEV Brazil	Industrial Mid. Temp	First Commercial Deployment	400KW	2MWh	Complete	Completed	Jun 2021 – Oct-21	Nov 2021 – Dec-21	2022
SUNY US	Cogen Commercial	First Commercial Deployment	500KW	510KWh	Jan 2020 – Jun-21	Completed	Jul 2021 – Dec-21	Jan 2022 – Mar-22	2022
IDF Israel	Industrial Mid. Temp	First Commercial Deployment	150KW	450KWH	Completed	Completed	Completed	Completed	Mar-21
ZELTMANN US	Power Utility	Commercial Pilot	4MW	16MWh	Apr 2021 – Aug-21	2022	2023	2024	2025

2.2.2 Commercial Application

Fossil fuels continue to be the main source of power generation in the U.S. In recent years, the relatively low cost of natural gas has allowed it to overtake coal as the dominant fossil fuel in the U.S. In addition, continued growth in power generation from variable renewable energy (VRE) sources challenges the stable operation of the power transmission and distribution system. The addition of energy storage to increase the flexibility of the fossil generation assets can help to address this challenge. The increased flexibility could support the further growth in integration of VRE sources, while maintaining stability and backup reserves for the electrical grid. The scalability of the Brenmiller bGen™ TES technology provides the opportunity for direct application to NGCC and other fossil generation assets that would benefit from increased flexibility due to VRE, across a wide range of plant sizes, and addresses thermal capacity storage needs from 0.5 MW-thermal to 1.0 GW-thermal.

TES is a natural fit for thermal plants as they are both use thermal energy, helping to minimize conversion losses. The bGen™ technology offers unique qualities to meet the needs and challenges of supporting flexibility and grid stability. In addition to offering relatively low cost per MWh and robustness, the technology can be deployed in modules to adapt to various plant sizes. The bGen™ technology can combine multiple thermal and electrical inputs, resulting in enhanced flexibility to both the plant's thermal cycles (gas, steam) and to the electrical side, as shown in Figure 2-1, as well as in Figures 2-7, 2-8, and 2-9.

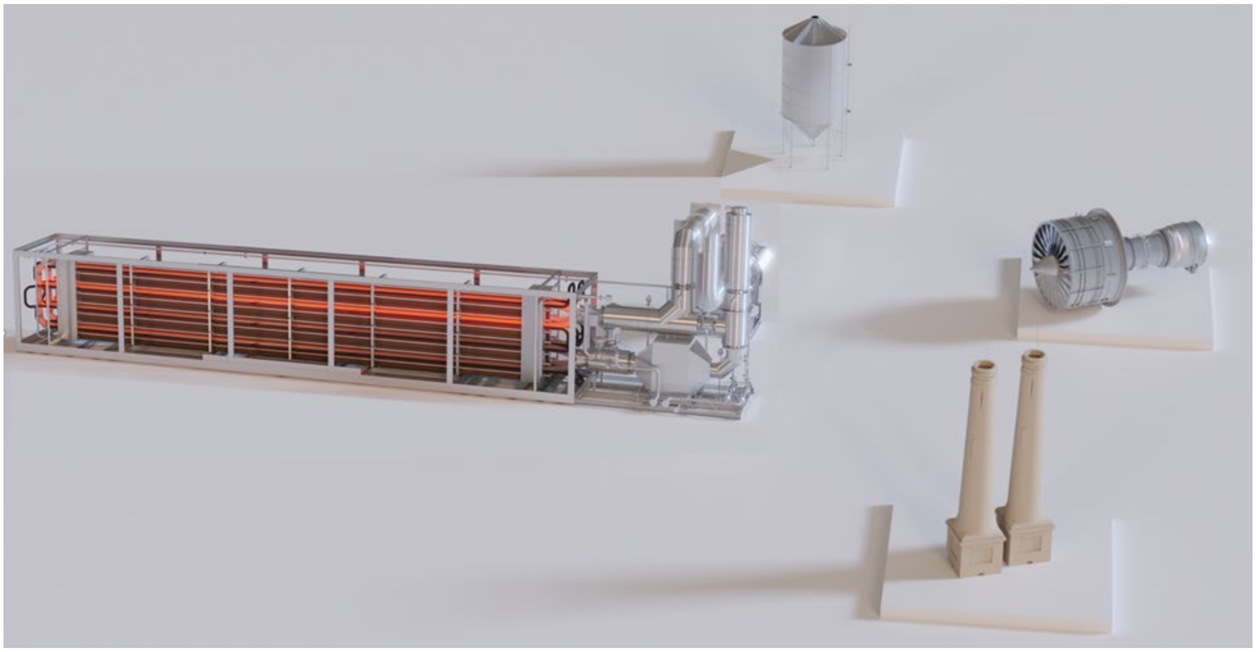


Figure 2-7. Thermal Charging of TES

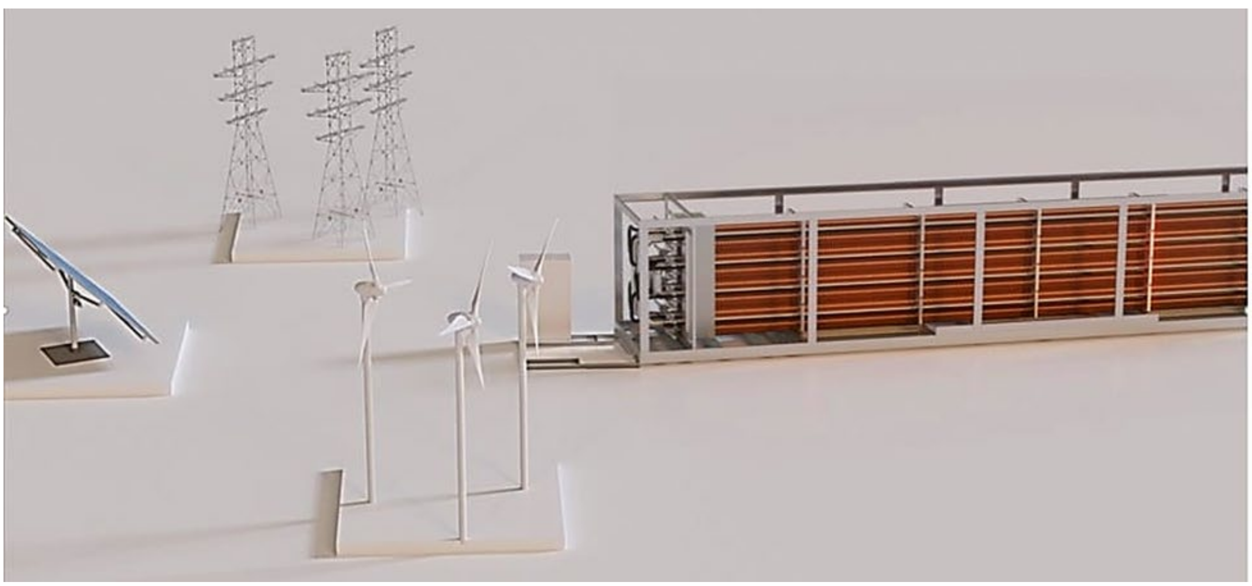


Figure 2-8. Electrical Charging of TES

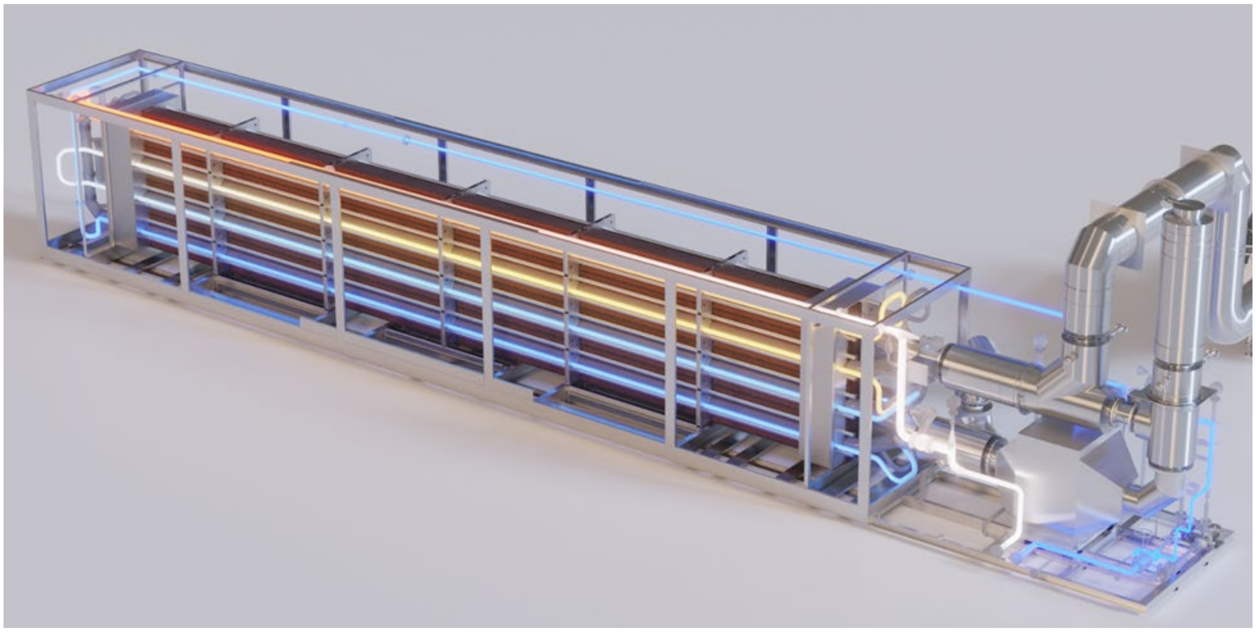


Figure 2-9. Steam Discharging from TES

2.3 Conceptual Study Steps

The tasks to be performed under the current project award intend to support a next-step pre-FEED for a pilot, which would advance the TRL of the crushed rock TES technology. If the effort is successful, the technology would advance from TRL 5 to TRL 6.

The program work builds upon the prior efforts of Brenmiller Energy, including multiple stages of pre-design, demonstration prototypes, lab testing, charging with multiple sources and measuring of output results.

The conceptual study task, as described in this chapter, covers the analysis of 4 different potential scenarios, to be installed at the NYPA Zeltmann power plant. Additional scenarios and combinations of the analyzed ones are valid while the selected ones are presenting the capabilities.

The scenarios are ranging from a pure thermal charging of the TES from the CT flue gases, taken from the 2 local combustion turbines output, up to a full charging of the TES with an electrical source, utilizing the hybrid charging capability of the bGen™. The utilized electrical sources are the local produced electricity or the future renewable electricity from Grid.

Each scenario is analyzed in multiple dimensions, starting from the concept description, the potential process flow diagram, its assumed streams of annual revenues, the incremental output power and capacity produced, the estimated investment per each scenario and the resulting NPV or return on investment for each scenario.

To have a balanced comparison, a storage capacity of 200 MWh thermal has been selected for all the 4 scenarios. This size was selected to enable the utilization of the existing installed capital equipment at Zeltmann plant for the incremental power produced by the TES, with no need to increase the capacity of the existing steam turbine. As will be shown in later chapters, such a TES size will add an increment of 17.8MW electricity power to the steam turbine output.

2.3.1 Selected site for the conceptual study analysis

Brenmiller technology will be analyzed for an installation at NYPA's Eugene W. Zeltmann Power Plant (Zeltmann), a natural gas combined cycle (NGCC) power plant. Figures 2-10, 2-2-11, 2-12 and 2-13, as well as Table 2-2, describe the plant location, its mechanical arrangement, and the existing plant power generation.

Figure 2-10. Zeltmann Plant – Queens, NY, Arial Photograph

Figure 2-11. Zeltmann Plant – New York City

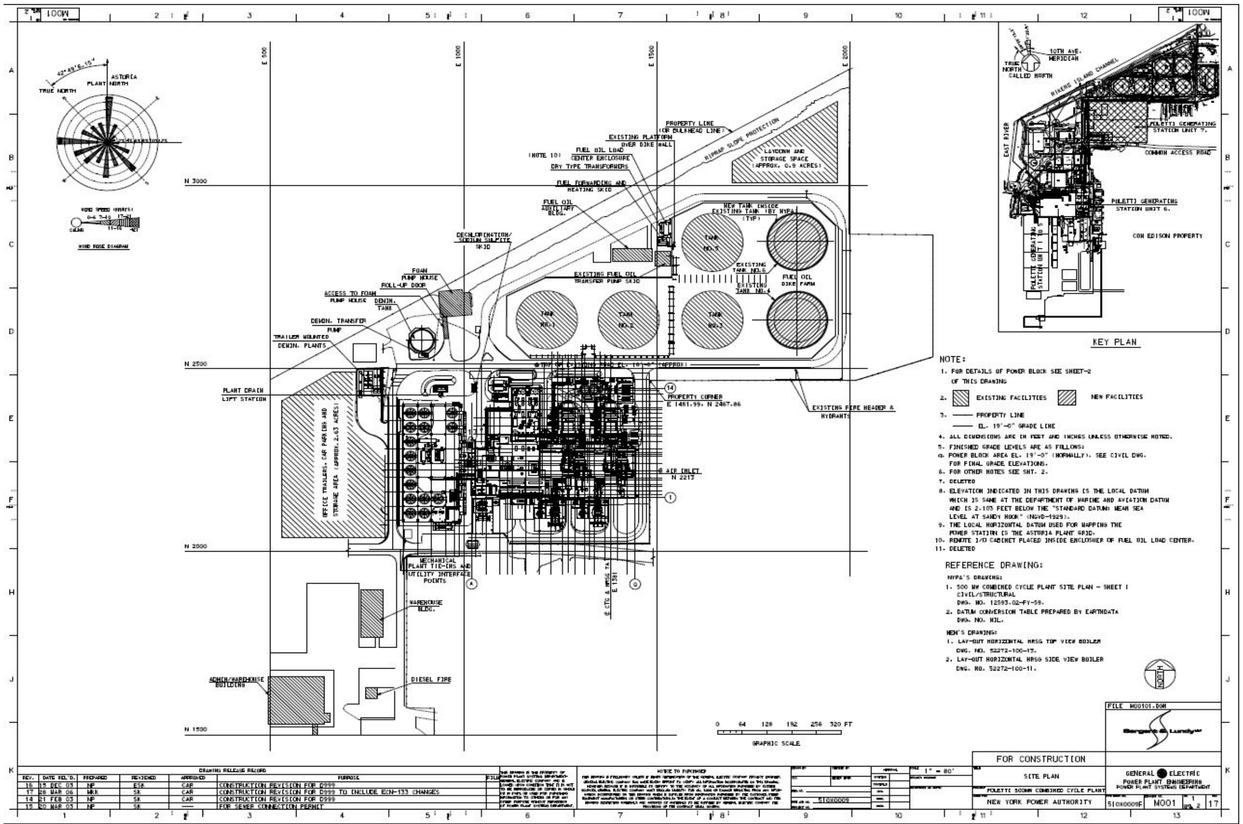


Figure 2-12. Zeltmann Plant – Site Plan

The current analysis assumes an installation of the TES at one of the prepared locations for a tank, one of the 6 locations shown in the above mechanical arrangement (see Figure 2-12), the closest to the two HRSG's and the steam turbine. This area is already prepared with foundations for the tank. Verification will need to be performed during later stages to verify the foundations are adequate for the loads applied by the TES system.

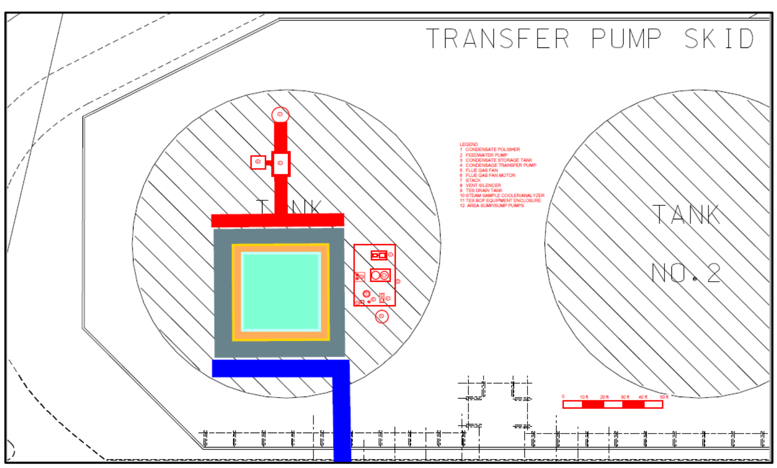


Figure 2-13. Zeltmann Plant - Mechanical Arrangement - Prepared Tank Location

Table 2-2. Zeltmann Plant Generation – Power (KW)

1	Gas Turbine Power (2 units)	350,960
2	Steam Turbine Power	188,370
3	Gross Equipment Power	539,330
4	Equipment Auxiliary Power	1,010
5	Net Equipment Power	538,320
6	Plant Auxiliary Power	25,030
7	Net Plant Power	513,290

2.3.2 Scenarios to be analyzed

The four Scenarios selected for the analysis, utilizing Brenmiller Energy TES and the Zeltmann site as the platform, are summarized in Table 2-3.

All scenarios are based upon a TES capacity of 200MWh thermal.

Scenario #1 Thermal Charging utilizes a partial output of the CT flue gases to fully charge the storage capacity at hours of low-cost electricity production (e.g., during overnight hours). The analysis is based on a total of 4 hours for charging. Discharging the accumulated energy out of the TES will be performed by discharging high temperature steam, directly out of the TES, to the steam turbine, using the temperatures and pressures, as required for a standard operation. Discharging will take place during high tariff hours for electricity production (e.g., 4:00 PM to 11:00 PM). For a balanced comparison and a wide view of the potential, since discharge is limited to 4 hours, an assumption was made to relate to the discharge production as incremental power to the existing production.

Scenario #2 Hybrid Flue Gas Charging utilizes the system's capability to charge the TES from both thermal and electrical sources, at different asynchronous time slots, while having an accumulated storage buffer from both the collected thermal and electrical streams. This scenario is combination of Scenario #1 (thermal charging) and Scenario #3 (electrical charging). The ratio of electrical charging versus thermal charging can be dynamically set and optimized over time with the changing penetration of renewable energy and fluctuations in market prices. Increasing prices of carbon credits in different regions and different real time prices during year seasonal fluctuations are reflected. Scenario #2 has been calculated to start charging using 80% of its capacity from the thermal source and 20% from electrical charging. Discharging the accumulated energy out of the TES utilizes the installed equipment, the steam turbine, supplying high temperature steam directly out of the TES, at the temperature and pressure required for a standard operation. The discharged production is considered as incremental to the existing production.

Scenario #3 Electrical Charing is based upon pure electrical charging of the TES. Using the inherent capability of the system to convert electricity to high temperature heat and accumulate it, the TES will be charged using low-cost locally produced electricity, or low-tariff renewable electricity from the grid during low-cost periods (e.g., 2:00 AM to 6:00 AM). The analysis is based on a total of 4 hours for charging. Discharging the accumulated energy out of the TES will be performed through the supply of high temperature steam, directly out of the TES to the steam turbine, temperatures and pressures required for standard operation. Discharging will take place during high tariff hours for electricity production (e.g., 4:00 PM to 11:00 PM). When charged from renewable grid electricity, this production can be observed as fully green. Also, in this scenario, discharge production is considered as incremental to the existing production.

Scenario #4 Hybrid Steam Charging utilizes the system's capability to charge the TES from both thermal and electrical sources, at different asynchronous time slots, while having an accumulated storage buffer from both the collected thermal and electrical streams. In this scenario the TES is being charged with flow of superheated steam from the HRSG and topped with additional charging from local electricity produced locally or from the grid. The topping with converted electricity to high temperature heat inside the TES enables it to produce steam exactly at the required conditions for the Steam turbine. To optimize the CAPEX investment, the scenario will enable or steam charging or discharging of the TES at the same time, but not in parallel. Charging with electricity can be performed at any time. The ratio of electrical charging versus thermal charging can be dynamically set and optimized over time with the changing penetration of renewable energy and fluctuations in market prices. Increasing prices of carbon credits in different regions and different real time prices during year seasonal fluctuations are reflected. Scenario #4 has been calculated to start charging using 75% of its capacity from the steam thermal source and 25% from electrical charging. Discharging the accumulated energy out of the TES utilizes the installed equipment, the steam turbine, supplying high temperature steam directly out of the TES, at the temperature and pressure required for a standard operation. The discharged production is considered as incremental to the existing production.

Table 2-3. Selected Scenarios for Analysis

	Scenario #1 Thermal Charging	Scenario # 2 Hybrid Charging Flue Gas	Scenario #3 Electrical Charging	Scenario # 4 Hybrid Charging Steam
Charging Source (4 hours)	CT flue gas	80% CT flue gas + 20% Electricity	Local or Grid Electricity	75% Steam + 25% Electricity
Discharging Target (4 hours)	Existing ST	Existing ST	Existing ST	Existing ST
Charging Temperature	1106°F (597°C)	1106°F (597°C)	-	1040°F (560°C)
Charging Pressure	14.5psi (1 bar)	14.5psi (1 bar)	-	1827psi (126 bar)
Discharging Temperature	1040°F (560°C)	1040°F (560°C)	1040°F (560°C)	1040°F (560°C)
Discharging Pressure	1827 psi (126 bar)	1827psi (126 bar)	1827psi (126 bar)	1827psi (126 bar)
Storage Size	200MWh	200MWh	200MWh	200MWh

2.3.3 Economic Analysis Methodology

The analysis focuses on the energy value of the bGen™ charging/discharging cycle for each scenario. Energy storage resources are also potentially eligible to receive capacity payments in the NYISO market. NYISO's data site provides public actual hourly and 5-minute electric energy prices for the period 2015 through 2021 at the Zeltmann node. Revenues of the proposed integrated bGen™ /Zeltmann energy storage system were calculated under several scenarios to determine the range of possible net energy revenues, as described below.

The energy arbitrage opportunities at a specific node depend on the differences between high and low prices. A storage system in purely economic operation would attempt to maximize the energy margin by storing energy when the values (i.e., prices) are lowest and discharging to the network (i.e., selling power) when the prices are highest. To establish a range of possible revenue outcomes, the theoretical maximum was examined as well as more practical scenarios considering the actual economic and technological constraints of the system.

Maximum Limit of Energy Arbitrage Opportunity

The ultimate theoretical maximum limit of energy arbitrage can be evaluated by creating a price duration curve, by ordering all electricity prices for a full year from lowest to highest. The theoretical limit of arbitrage revenues is based on several assumptions: $0 variable cost of the storage process/equipment; no limit to the storage capacity; ability to operate in every hour of the year; and 100% conversion efficiency. Such a system could "buy" during the 4,380 hours in which power is cheapest and "sell" during the 4,380 hours in which power is more expensive. With these parameters, the potential energy arbitrage margins were calculated based on the last five years of real-time and day-ahead price data at the specific Zeltmann node (using actual hourly and 5-minute real-time data). The average theoretical value over the study period (excluding the 2020 calendar year that was skewed due to COVID-19 pandemic influences) was $7.67/kW-month using day-ahead prices and $9.75/kW-month using real-time prices (see Table 2-4).

Table 2-4. Maximum Theoretical Energy Arbitrage Margin for a 1MW system based on actual historical prices at the Zeltmann node (no operational constraints) $/KW-month

Data Year	Day Ahead Arbitrage Margin $/KW-month	Real Time Hourly Arbitrage - $/KW-month
2016	$7.10	$9.00
2017	$7.44	$9.63
2018	$9.87	$12.98
2019	$6.28	$7.40
2020	$4.14	$5.17
Average 2016-2020	$6.97	$8.84
Average 2016-2019[1]	$7.67	$9.75

[1] The data for year 2020 was highly unusual relative to prior years and the preliminary data for 2021 (through August). Price volatility was severely affected by the Covid crisis and the subsequent lockdowns, and the implied margins were unusually low. Preliminary margins data for 2021 is trending 80% higher than 2020 and very close to the 2016-2019 averages.

The same exercise was applied to 5-minute Real Time price data and produced roughly 5% higher margins (see Figure 2-14).[2] Average prices for 2020 and 2021 are shown in Figure 2-15.

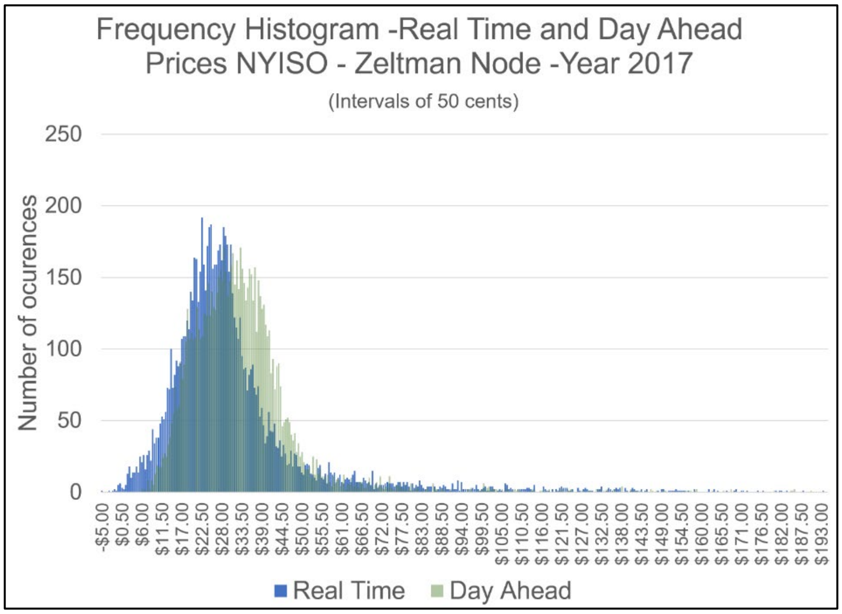


Figure 2-14. Zeltmann Node Energy Price Probability Distribution – 2017 example

[2] The relatively small increase in the margin when using more granular data is unusual when compared to other US markets with substantially higher renewable penetration. In markets like CAISO (high solar penetration) or SPP (high wind penetration), 5 minutes data analyses of storage benefits can translate into even higher margin increases relative to hourly data (10-20% higher).

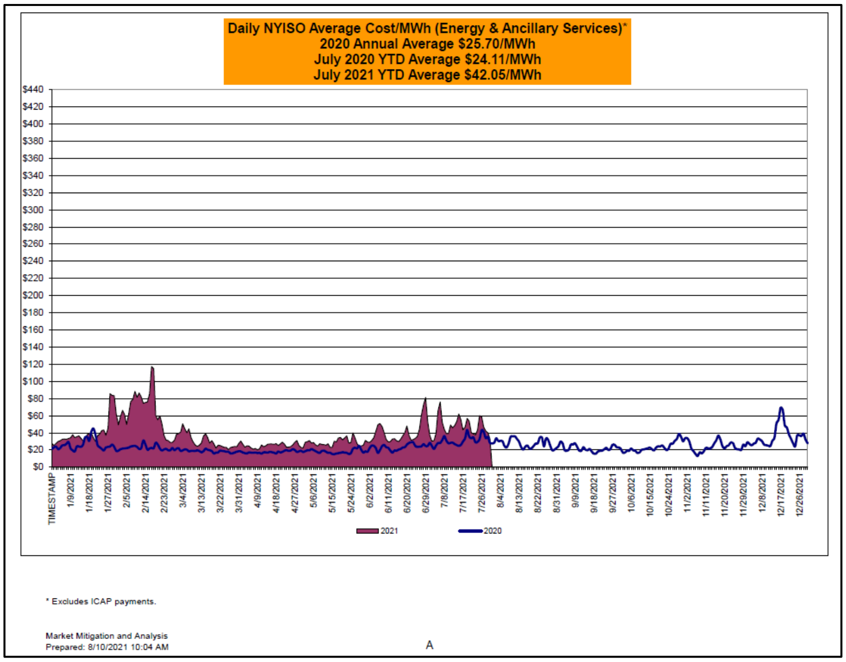


Figure 2-15. Zeltmann 2020 & 2021 Average Prices

Constrained Energy Arbitrage Analysis

Next, the energy arbitrage margins available to the bGen™/Zeltmann storage system during the same 5-year study period were examined using a series of real-world constraints on the system operation.

<u>Storage Size (Duration) Relative to Peak Output</u>

The size of the storage (i.e., duration of discharge time) relative to peak output is an important determinant of revenues as well as capital cost. Determining the optimal duration of storage is a key consideration and deserves more study in the NYISO market, particularly with increasing penetration of renewables.

The classic scenario of energy arbitrage for a storage system includes buying low-cost power during the night (e.g., power produced by wind generation, with prices approaching $0 or even negative as we have seen in other markets such as SPP) and then selling during the peak-cost daytime hours — approximately 12 hours. The optimal duration of energy storage depends on the economic process of buying and selling, including actual price volatility, probability distribution and price autocorrelation effects. Frequently a low-cost and a peak-cost hour are much closer than 12 hours and a beneficial transaction can be performed in a shorter storage period. Furthermore, the concentration of large price variations in a few hours makes this effect much stronger. While it could be said that the "optimal" transaction will be buying during the "cheapest" hour of the night and selling that at the "highest" price, some "good enough" transactions (profitable for the owner) can happen with substantially less storage, and this effect is particularly noteworthy in the real-time price series. The system might not always capture the largest price differential of the cycle, but it will make several economic transactions that are economically advantageous.

System Efficiency

For scenarios #1 and #2, which incorporate thermal charging, an efficiency factor is introduced in percentage terms to account for the energy losses due to the process of heat storage and steam generation. As will be presented inside PFD's for each scenario, the charging efficiency of the Brenmiller Energy crushed-rock, TES system (output divided by energy input) is 94.7%. The bGen™ thermal storage is also subject to a small time-related degradation factor as heat slowly escapes the storage media. Based on the performance analysis previously completed by Brenmiller Energy an energy efficiency level of 92% has been selected as an initial test point to develop the arbitrage opportunities[3]. The 92% efficiency refers to the capability of extracting flue gas from the system to provide heat to the storage system and returning that power to the electric STG.[4]

Actual Plant Operating Hours

The bGen™ storage system can only discharge power when the Facility is operating, thus the deployment of bGen™ is constrained to the actual Zeltmann operating hours. The Zeltmann Facility does not operate 100% of annual hours because of economic dispatch factors and maintenance periods in which the plant is offline. The historical Facility capacity factor is above 50% but more relevant to the bGen™ system, the plant is generating during 85%+ of annual hours because often only one of the two CT units is on, frequently at partial output. Interestingly, the reduction from operating 100% of the time does not imply a proportional reduction in the energy revenues. The storage system will extract more of the arbitrage value in the hours in which the plant is operational since the plant runs most frequently at higher value hours. From our estimation, if the plant is operational 85% of the time the bGen™ operations could achieve somewhere around 90%+ of the energy margin relative to a comparable system located in a facility that operates 100% of the time. Historical data on the Zeltmann power generation can be found in the Appendix (see Table 2-29).

Storage Decision Algorithm

As part of the project team, Kelson Energy was tasked with contributing to the economic analysis by applying their experience within the US electric power industry. Kelson has deep day-to-day operating experience offering power assets into the competitive electricity markets in the NY, California, New England and SPP markets. Kelson has developed a proprietary

[3] The efficiency level without degradation due to time in storage is in the 94.7% range according to BGEN specifications. In addition to that the system has a time degradation of 3% / day, which would imply a 91.9% at the end of the first day of storage. As we will show in the examples, most of the energy arbitrage value happens in a relatively short number of hours of available storage.
[4] This efficiency level should not be confused with the thermal efficiency of the combined cycle (ability to transform the energy content of the fuel into electric power). Thermal efficiency is in the 45-60% range for most combined cycles. The energy efficiency of the BGEN storage system as described here is evaluated after the energy is produced by the NGCC.

sequential algorithm that evaluates prices for the next X hours[5] and determines which are the lowest cost hours to buy and most valuable hours to sell. At every hour, the system will "look forward" at the next few hours and compare those to the current hour price. The system evaluates how much storage is available and whether to "buy" or "sell" during the current hour. This method enables a basic estimation of energy arbitrage revenues and can also reveal how the value is affected by additional storage duration hours.

Historical Analysis

Using the developed algorithm, simulation for integrated bGen™/Zeltmann TES system "buy/sell" activity was performed on an hourly basis using actual NYISO Zeltmann nodal day-ahead and real-time price information for the last five years. The results are tabulated below in Tables 2-5 and 2-6, which reflect bGen™ storage duration and efficiency constraints. The calculation estimation is made that the loss in energy arbitrage revenue opportunity during Zeltmann's offline periods are minor and no adjustment was made for this constraint.

Table 2-5. Real-Time Market Results: Theoretical limit on Real Time Arbitrage with no limitations (hourly data) vs 24 hour and 4-hour storage duration under the stylized algorithm tested with efficiency limitations (no plant capacity factor limitations)

Comparison of Storage size -Real Time - Margin in $/KW-month

Data Year	Theoretical Limit with no operational or storage constraints (Real Time)	24 hour storage with efficiency constraints - simple sequential algorithm	4 hour storage with efficiency constraints - simple sequential algorithm	24 hour storage - % ratio to limit value	4 hour storage - % ratio to limit value
2016	$9.00	$5.99	$4.37	66.6%	48.6%
2017	$9.63	$6.10	$4.47	63.3%	46.4%
2018	$12.98	$7.82	$5.59	60.2%	43.0%
2019	$7.40	$4.55	$3.22	61.5%	43.5%
2020	$5.17	$3.39	$2.44	65.6%	47.2%
Average 2016-2020	$8.84	$5.57	$4.02	63.0%	45.5%
Average 2016-2019	$9.75	$6.11	$4.41	62.7%	45.2%

In comparing the analysis based on real-time prices with day-ahead, the real-time results are about $2+/kW-mo higher (see Figure 2-15). The assessment is that a strategy including both real-time and day-ahead sales can result in a better outcome than either approach in isolation. The interplay between real-time and day-ahead strategies requires more analysis, but as an estimate it is suggested to add $1/kW-mo to the real-time case result to account for this potential.

[5] The algorithm assumes "perfect forward view" for a limited number of hours.

Table 2-6. Day-Ahead Market Results: Theoretical limit or Day Ahead Arbitrage with no limitations vs 24 hour and 4-hour storage duration under the stylized algorithm tested with efficiency limitations (no plant capacity factor limitations)

Comparison of Storage size - Day Ahead - Margin in $/KW-month					
Data Year	Theoretical Limit with no operational or storage constraints (Day Ahead)	24 hour storage with efficiency constraints - simple sequential algorithm	4 hour storage with efficiency constraints - simple sequential algorithm	24 hour storage - % ratio to limit value	4 hour storage - % ratio to limit value
2016	$7.10	$3.86	$2.29	54.3%	32.2%
2017	$7.44	$3.70	$2.37	49.7%	31.9%
2018	$9.87	$4.60	$2.77	46.6%	28.0%
2019	$6.28	$2.96	$1.73	47.1%	27.6%
2020	$4.14	$2.06	$1.23	49.7%	29.6%
Average 2016-2020	$6.97	$3.43	$2.08	49.3%	29.8%
Average 2016-2019	$7.67	$3.78	$2.29	49.2%	29.8%

Additional information on the Sensitivity to Storage Sizes can be found in Appendix 7.0.

Summary of the Sources of Increased Value

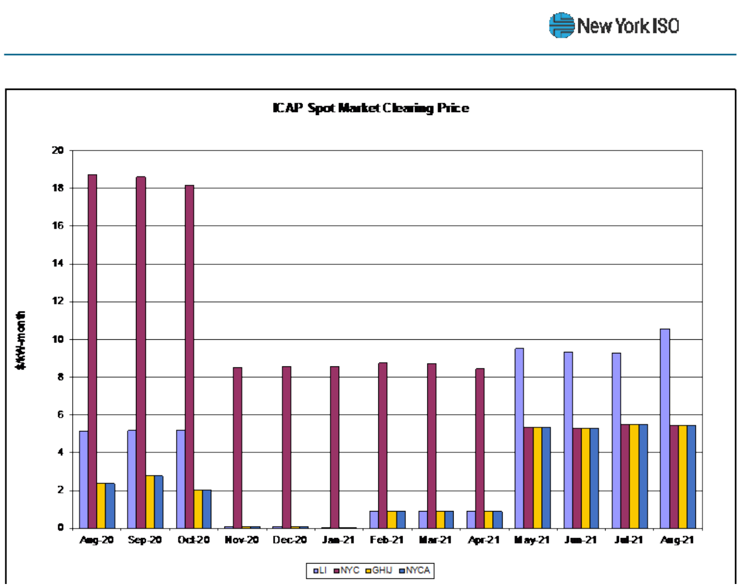
- Optimization of real-time and day-ahead revenues – add $1/kW-mo to real-time result
- Enhanced operation of the integrated TES system (via better software programming and/or human intervention) should logically yield even higher shares of the potential margin for a given storage size – estimated up to 30% improvement. There is still a substantial range of benefit to be captured by implementing better systems of energy management for the bGen™ system.
- Ancillary Services – adding regulation, spinning reserve and VAR support revenues has the potential of $0.25/kW-mo
- Increasing price volatility resulting from increasing renewables penetration – Other U.S. markets such as SPP and California, which have experienced a significant penetration of renewables, present an increasing energy price volatility. (see analysis below). As offshore wind and solar generation appear in the NYISO market, a significant increase in price spreads with higher highs and lower (including negative) lows is expected.
- Emission reductions will be achieved in the scenarios utilizing grid electrical energy for TES charging. The bGen™ TES will enable renewable grid energy utilization using the embedded conversion functionality. It will enable additional plant generation while

reducing the natural gas consumption. The result is a gradual shift to renewables at the plant, gradual reduction of plant emissions adapted to rhythm of renewables grid penetration at the Zeltmann arena. The calculation of emissions reduction will be based on the ratio of used renewables and the emissions per saved Natural Gas.

- Carbon pricing should also have an increasing impact on price spreads as renewables increasingly become the marginal unit especially during low-load, off-peak periods.

NYISO Capacity Market Revenues

New York has a capacity market that was expanded to include storage resources. Each month there is a spot auction and the NYISO reports on those prices (see Figure 2-16). The capacity



NYISO CAPACITY CREDIT

Market Capacity Prices

Spot Capacity Price History (NYC Zone)

	$/kW-yr	
2022	$3.42	**$6.16** (2022 – 2021 Q1)
2021 Q2	$6.37	
2021 Q1	$8.68	
2020 Q4		
2020 Q3	$13.33	
2020 Q2	$13.25	
2020 Q1	$3.75	
Average	**$8.13**	

2021/22	$3.42
2020/21	$13.33
2019/20	$8.33
2018/19	$5.83
Average	**$7.73**

Use for 2022 **$5.00**

Figure 2-16. New York ISO Graphic on Recent Capacity Market Clearing Prices

prices differ in each of the NYISO "zones" (Astoria/Queens is in the New York City Zone, which tends to have the highest prices). For storage resources, there is a derating adjustment factor that applies for storage duration less than 8 hours. A 4-hour system of the bGen™ size would receive 90% of the full capacity credit. There has been significant price volatility over the past year. For the economic analysis of this project, $5.0/kW-mo was selected as it reflects the most recent market clearing prices.

Future Volatility Due to Renewable Penetration and Carbon Prices

The analysis of renewables-heavy markets and markets with higher carbon prices shows that both renewables and carbon prices have an increasing effect on energy price volatility and high-low spreads. The CAISO market (California) shows both high renewable penetration (mostly solar power but also wind, hydro and geothermal) and substantial carbon prices. The effects on volatility due to these factors are twofold: not only do the price probability distributions get "wider" but it becomes more skewed and more asymmetric. The standard deviation of day-ahead prices in California has been increasing enormously in the last few months and is currently reaching values in the $30-40/MWh, almost triple the values of NY which are in the $10-15/MWh range.

Another market with high renewable penetration is Southwest Power Pool (SPP). Wind is the dominant renewable in SPP, which is forecast to be increasingly relevant for the NY market. Both SPP and CAISO already have levels of renewable penetration that NY expects to reach in a few years under current regulatory plans. The SPP market has over 26,128 MW[6] of installed wind generating capacity in a market with a peak load of about 50,000 MW. SPP has set US records for wind penetration, recently reaching 84.2% of total market generation during March 29th, 2021. Wind generation has been the dominant source of generation in SPP during 2021, exceeding both gas-fired and coal-fired generation and often resulting in negative day-ahead and real-time energy clearing prices.

To evaluate the potential impact of substantially higher carbon prices in the energy price volatility, a market simulation based on SPP's current power plant mix was tested. The results of the simulation are summarized on Table 2-7.

The variability can be measured by statistical techniques including comparing standard deviations among other measures like Mean Absolute Deviation. The effect in the increased standard deviation[7] translates linearly to the estimated maximum margins of the storage system[8].

[6] According to EIA 860 reports – updated through June 2021
[7] There are some potential non-linear effects in the actual results versus the simulated results as the distribution of probability are not gaussian and are instead fat tailed. However, those effects that increase the "right tail" would imply increases in margins that are above the linear effect in a constrained case of storage hours. For simplicity, at this stage of analysis, we will assume linearity.
[8] This is a valid assumption when comparing the same system over time and/or its changes.

Table 2-7. Carbon price simulation results

Change in Volatility due to Carbon Price levels: Simulated results for a market with high renewable penetration (SPP)			
	Simulated Carbon Price		
	0	$30/ton	$60/ton
Resulting Standard Deviation :Day Ahead Price (Hourly Prices)	$17.70	$34.62	$52.45
Increase over case with no carbon price		95.6%	196.3%

An increase in carbon prices to 60$/ton, implies a 196% increase in Standard Deviation. Essentially, the probability distribution became 3x wider in that case. That would translate into a 3x increase in the implied maximum margin of a storage system in that market.

It should be noted that while the New York market already has a carbon offset requirement (via RGGI), the average RGGI price in the studied period (9/2015 through 8/2021) has been $5.17/ton which translates into a relatively muted effect so far.

The California greenhouse gas ("GHG") prices are currently in the $25/ton range and GHG prices in Europe are in the 60$/ton range, which may be considered indicative of future prices in the NY market.

To make our economic and financial analysis consistent with the stated ambitious environmental goals of New York we focused on scenarios in which carbon prices reach values in the order of 50$/ton.

The standard deviations cannot be compared across markets without the full context of the distribution shape, but the variations and percentage changes of that deviation provide a stronger directional indicator. For a change between the current $5 - $10/ton range to the future $50/ton we estimated a linear change of 140% of the expected margin. This affects both Day Ahead and Real Time margins.

This effect is reflected in the analysis with and incremental addition of $8.0/kW-mo to the energy margin between 2023 and 2030.[9]

[9] The 8$/KW-month in 2030 dollars imply a 106% increase of the DA+RT margin in that year (on the lower side of the expected range).

2.3.3.1 Scenario 1 – Flue Gas Charging of TES

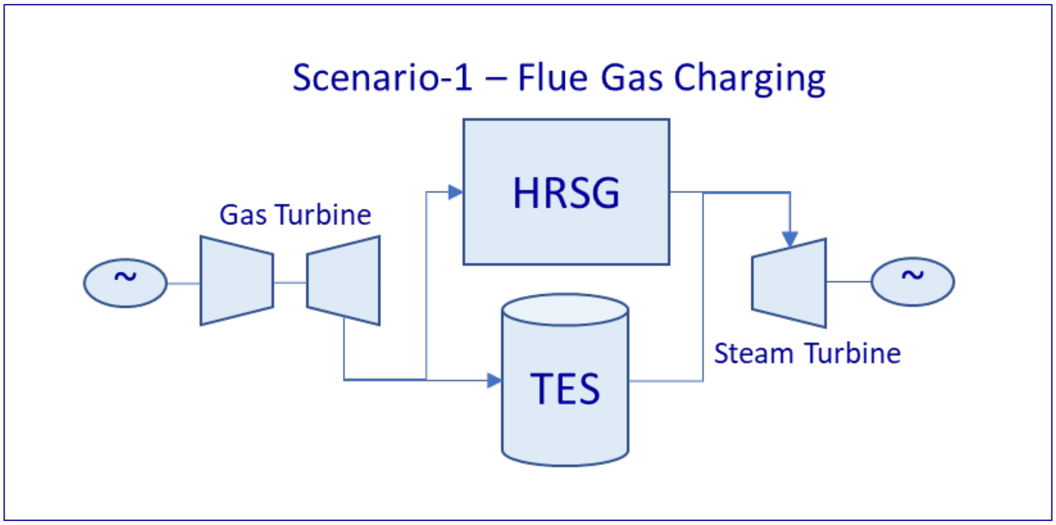


Figure 2-17. Scenario #1 – Flue Gas Charging

In Scenario #1, shown in Figure 2-17, the combustion turbine exhaust gas is extracted of the heat recovery steam generator (HRSG") to heat the bGen^{TM} energy storage at 1,040°F (560 °C). The bGen^{TM} charging cycle would occur primarily during off-peak periods when power prices are low and/or the Facility is operating in turndown mode. During periods of premium power prices (day ahead or real-time prices), discharge cycle will be activated by flowing feedwater through the hot bGen^{TM} media causing the feedwater to flash to high-pressure steam at 1,827 psi, and 1,040°F (126 bar, 560°C) that would be combined with steam flowing from the HRSG and admitted into the steam turbine to produce additional electric power.

Together, the bGen^{TM} charge and discharge cycles create a device that stores low-value, off-peak energy and re-injects that energy into the Facility steam cycle to boost steam turbine generator ("STG") electric output during periods of high electricity demand/prices. The charging energy—the 1,040°F (560°C) exhaust gas—comes at the cost of reduced electricity output in the STG.

The ratio of extracted flue gas used to charge the TES is calculated according the installed TES size, 200MWh thermal, in the current project analysis. The analysis is based on 4 hours of charging and 4 hours of discharging. Optimal hours for charging could be selected, typically during the night (e.g., 4:00 PM to 11:00 PM) based upon data from Zeltmann. The bGen^{TM} crushed-rock TES system facilitates charging or discharging the storage capacity across multiple time slots, and charging does not need to be performed in one continuous interval. The additional power output of 17.8 MW may be considered incremental to the current plant generation since the steam turbine usually does not reach its maximum and the additional power is only 4 hours in duration.

Heat Balance and Process Flow Diagram

The following Heat Balance Diagrams, shown in Figures 2-18, 2-19 and 2-20, represent the flue gas charging and the discharging modes using the Brenmiller crushed-tock TES. Flow parameters are used later in the performance and financial analysis.

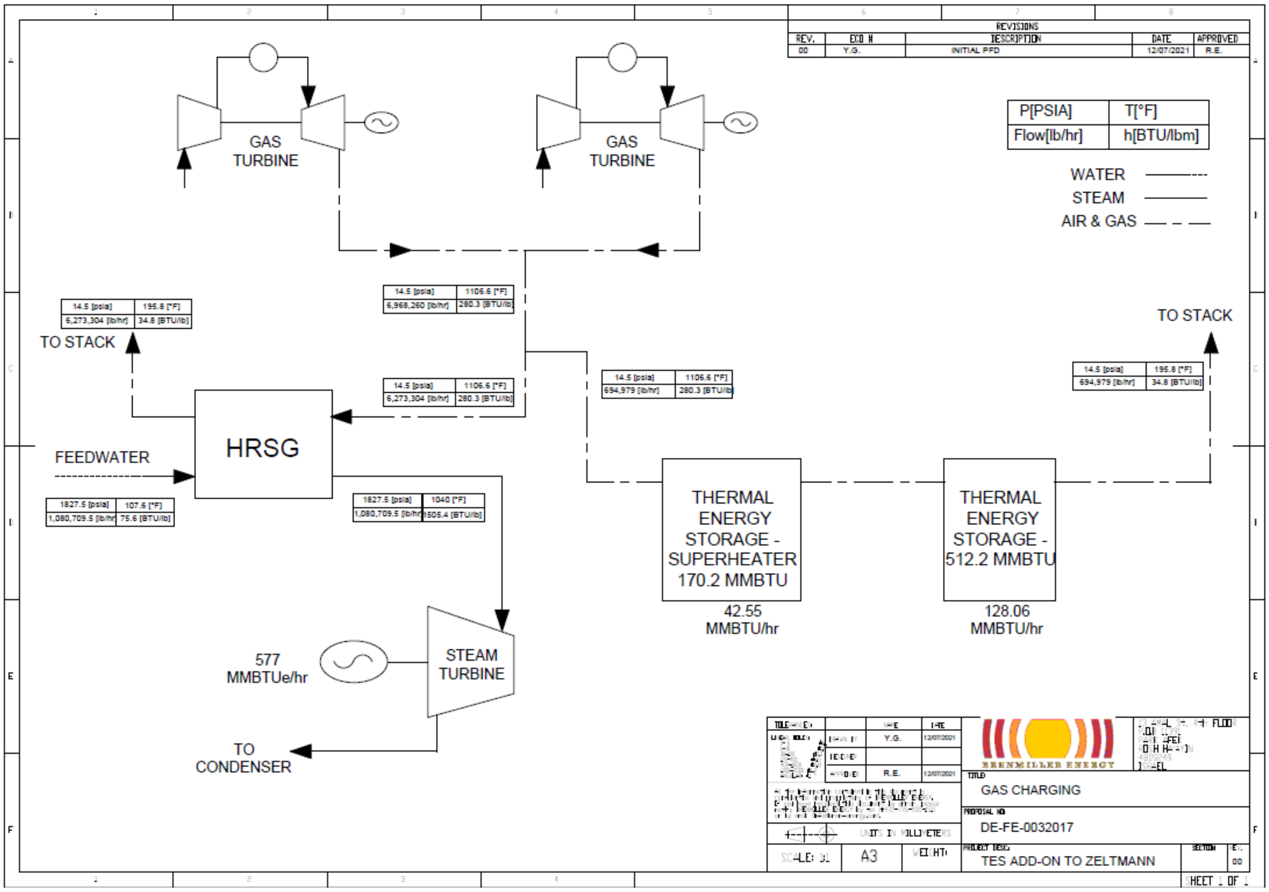


Figure 2-18. Scenario #1 – Flue Gas - Charging Heat Balance

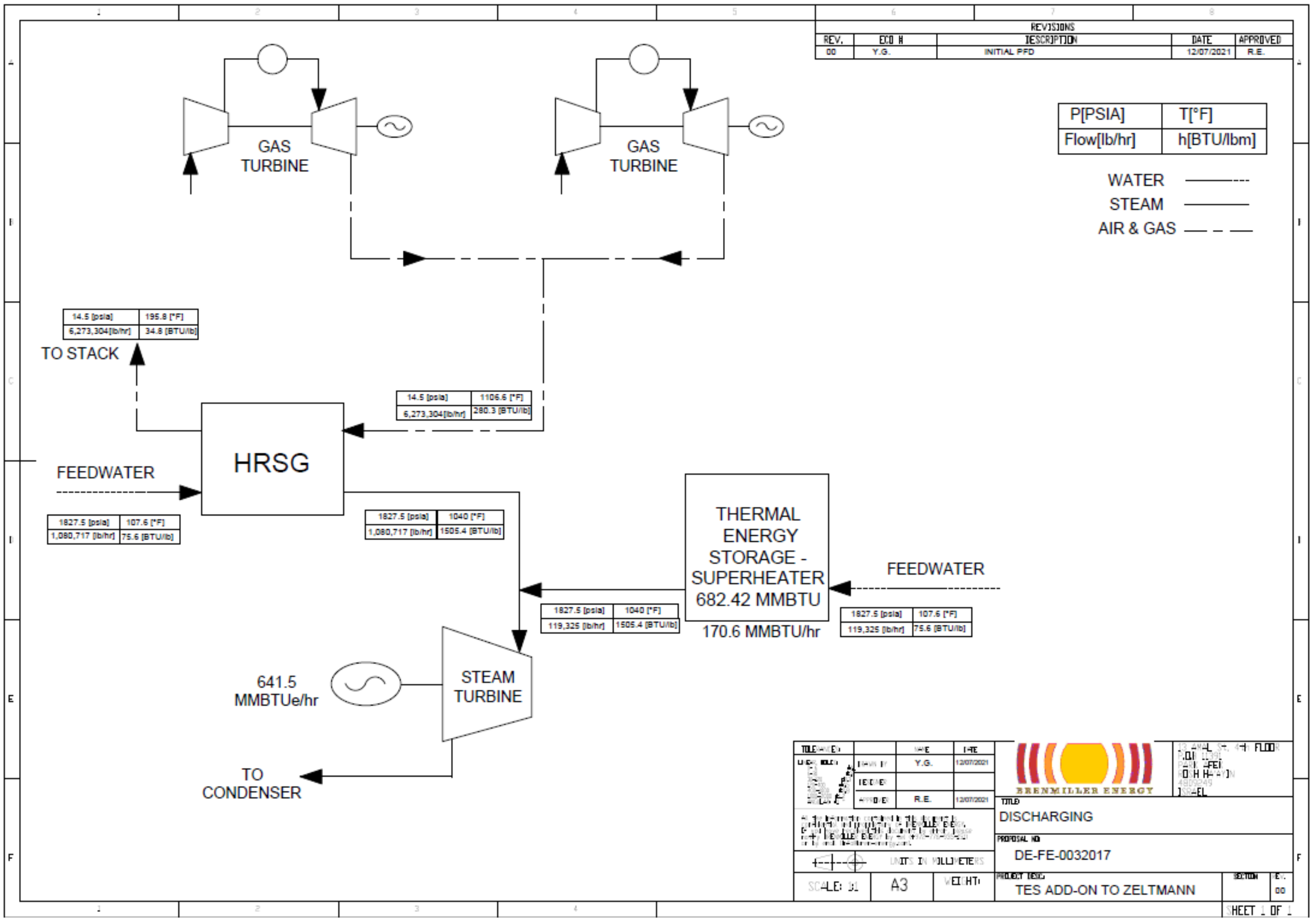


Figure 2-19. Scenario #1 - Discharge Mode – Heat Balance

Additional analysis is presented in the following Process Flow Diagram (see Figure 2-20):

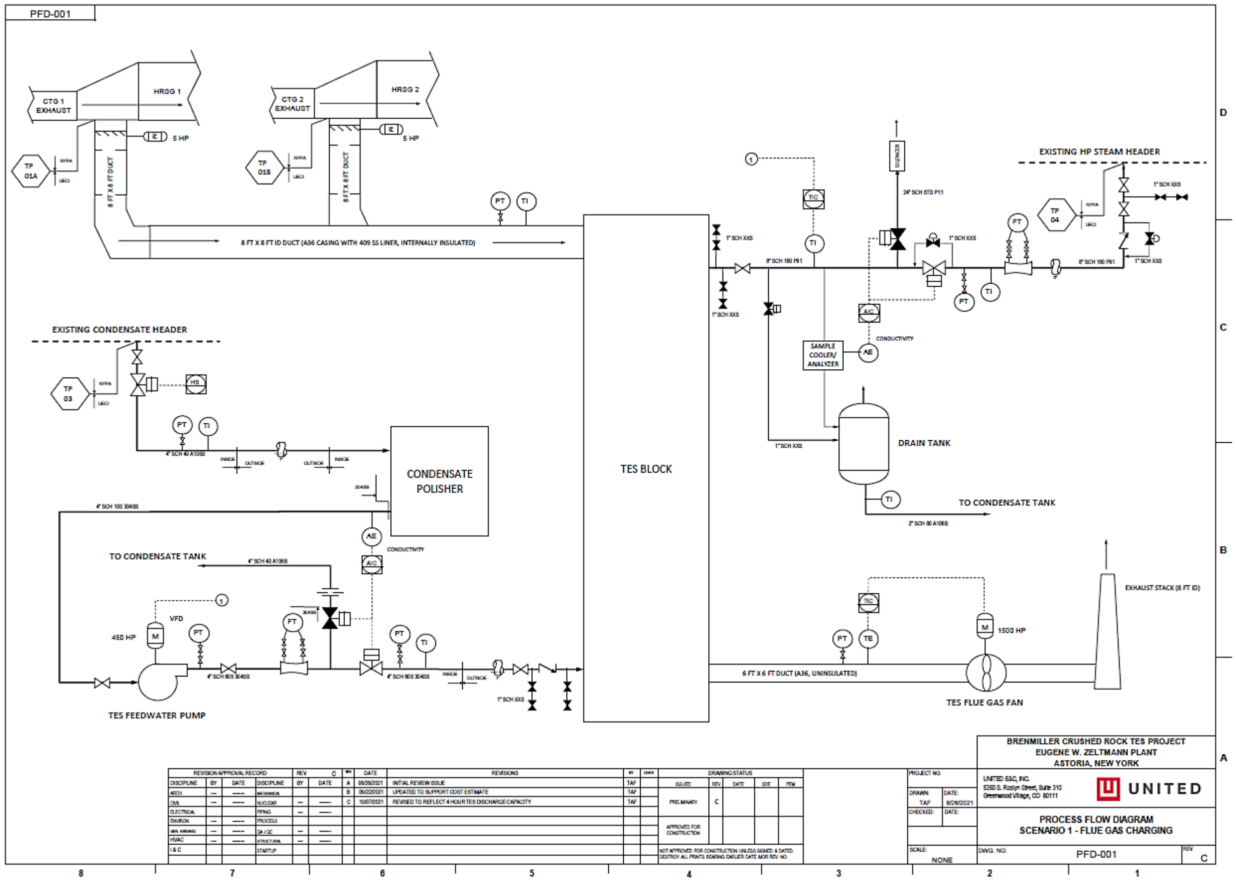


Figure 2-20. Scenario #1 –PFD

Performance Analysis and Financial Results

Using the above configuration, working points, and a bGen^{TM} of 200MWh thermal capacity, Table 2-8 outlines the incremental generation of the TES.

Table 2-8. Key Charging and Discharging Energy Flows

Energy Flow	Charging	Discharging
CT exhaust gas at 1,040°F (560°C)	694,976 lb/hr	
Off-Peak Loss of STG Output	18.8 MW	
Additional Steam Flow to STG		113,289 lb/hr
On-Peak Gain in STG Output		17.8 MW

For the present analysis, the bGen^{TM} heat exchanger is sized to provide 4 hours of discharge operation at the rated discharge steam flow and electric output. In the NYISO market, energy storage resources are eligible to receive different levels of capacity credits at discharge duration periods from 2 to 8+ hours.

Using the methodology and principles as described in above chapter **3.3 Economic Analysis Methodology,** the following potential revenue streams are considered:

1. Energy Arbitrage based on historical real time prices
2. Additional margin for optimization of the Day Ahead prices with the real time prices
3. Ancillary services
4. Margins resulting from the penetration of renewables and carbon credits prices
5. Capacity payments for a storage system in the NYISO arena

Values of these potential revenue streams are presented in Table 2-9, assumed for 2023. Cash Flow Analysis will assume the development of each of these streams along the future years.

Table 2-9. Potential Energy Arbitrage and Capacity Value of bGenTM Storage

Sources of Increased Value of Storage (2023)	**Energy Margin $/kW-mo**
Deployment based on historical RT prices (4-hr storage)	$4.62
Combination with DA activity + Overall optimization	$1.58
Ancillary services	$0.26
Renewable's penetration, less carbon in off-peak prices	$0.50
Capacity Revenues (Net of ICAP/UCAP and derating factors)	$5.13
Total Energy Margin + Capacity Payment	**12.09**

For a cash flow analysis, the calculated required investment is needed. The next stages of Pre-FEED and detailed design will more accurately calculate the required investment. Costs may be optimized during the detailed design stage. Larger future installations and multiple sites can reduce the overall required investment. Table 2-10 includes the estimated required cost of investment of the scenario #1.

Table 2-10. Required Investment for Scenario #1

Configuration main blocks – Cost	**$ M**
200MWh bGen^{TM} Storage	$10.0
BOP Connection, installation, and Commissioning	$20.7
Total Cost	**30.7**

It is assumed that the existing O&M team of the Zeltmann plant will take control of the TES operation at no additional cost due to its passive nature. Additional maintenance cost of the TES is estimated to be $ 258,000.

The cash flow analysis and the IRR calculation are summarized in Tables 2-11 and 2-12.

Table 2-11. Project IRR - Scenario #1 - Source of charging energy: CT Exhaust gas 1040F

		2023	2033
Operating Parameter			
Power Gen capability	kW	17,800	17,800
Electric storage capability	MWh	71.2	71.2
Derated/Adjusted capacity	kW	15,120	15,120
Assumed cycles per day	cycles/day	1.5	1.5
Selling hours	%	1,971	1,971
Annual generation	MWh	35,084	35,084
Revenues/Margins			
Real time margin	$/KW/mo	4.62	5.91
Adder for DA and optimization	$/KW/mo	1.58	2.02
Inc. volatility + Renewables + CO2	$/KW/mo	0.5	8.41
Ancillary services	$/KW/mo	0.26	0.33
Capacity price	$/KW/mo	5.13	6.57
Total revenues	**$/KW/mo**	**12.09**	**23.24**
Anuual revenues			
Real time margin	$/yr	986,832	1,263,228
Adder for DA and optimization	$/yr	337,488	432,013
Inc. volatility + Renewables + CO2	$/yr	106,800	1,795,308
Ancillary services	$/yr	55,536	71,091
Capacity price	$/yr	930,787	1,191,486
Total revenues	**$/KW/mo**	**2,417,443**	**4,753,127**
Maintenance cost			
Variable maintenance cost	$/yr	29,237	35,640
Fixed maintenance cost	$/yr	229,500	279,759
Net cash flow	$/yr	**2,158,706**	**4,437,728**
Investment	$	30,695,582	
Project IRR	%	**11.8%**	

Table 2-12. Cash Flow Analysis – Scenario #1

Source of charging energy: CT Exhaust gas 1107F												
		2023	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2050**	**2051**	**2052**
Operating Parameter												
Power Gen capability	kW	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800
Electric storage capability	MWh	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2
Derated/Adjusted capacity	kW	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120
Assumed cycles per day	cycles/day	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Selling hours	%	1,971	1,971	1,971	1,971	1,971	1,971	1,971	1,971	1,971	1,971	1,971
Annual generation	MWh	35,084	35,084	35,084	35,084	35,084	35,084	35,084	35,084	35,084	35,084	35,084
Revenues/Margins												
Real time margin	$/KW/mo	4.62	4.74	4.85	4.98	5.10	5.23	5.36	5.49	9.00	9.22	9.45
Adder for DA and optimization	$/KW/mo	1.58	1.62	1.66	1.70	1.74	1.79	1.83	1.88	3.08	3.15	3.23
Inc. volatility + Renewables + CO2	$/KW/mo	0.5	1.5	2.5	3.5	4.5	5.5	6.5	7.5	12.79	13.11	13.44
Ancillary services	$/KW/mo	0.26	0.27	0.27	0.28	0.29	0.29	0.30	0.31	0.51	0.52	0.53
Capacity price	$/KW/mo	5.13	5.26	5.39	5.52	5.66	5.80	5.95	6.10	9.99	10.24	10.50
Total revenues	**$/KW/mo**	**12.09**	**13.38**	**14.68**	**15.98**	**17.29**	**18.61**	**19.94**	**21.28**	**35.36**	**36.25**	**37.15**
Anuual revenues												
Real time margin	$/yr	986,832	1,011,503	1,036,790	1,062,710	1,089,278	1,116,510	1,144,423	1,173,033	1,922,151	1,970,205	2,019,460
Adder for DA and optimization	$/yr	337,488	345,925	354,573	363,438	372,524	381,837	391,383	401,167	657,359	673,793	690,638
Inc. volatility + Renewables + CO2	$/yr	106,800	320,400	534,000	747,600	961,200	1,174,800	1,388,400	1,602,000	2,731,773	2,800,068	2,870,069
Ancillary services	$/yr	55,536	56,924	58,348	59,806	61,301	62,834	64,405	66,015	108,173	110,877	113,649
Capacity price	$/yr	930,787	954,057	977,908	1,002,356	1,027,415	1,053,100	1,079,428	1,106,413	1,812,987	1,858,312	1,904,770
Total revenues	**$/KW/mo**	**2,417,443**	**2,688,809**	**2,961,620**	**3,235,910**	**3,511,718**	**3,789,081**	**4,068,038**	**4,348,629**	**7,232,444**	**7,413,255**	**7,598,587**
Maintenance cost												
Variable maintenance cost	$/yr	29,237	29,822	30,418	31,027	31,647	32,280	32,926	33,584	49,904	50,902	51,920
Fixed maintenance cost	$/yr	229,500	234,090	238,772	243,547	248,418	253,387	258,454	263,623	391,730	399,565	407,556
Net cash flow	$/yr	**2,158,706**	**2,424,898**	**2,692,430**	**2,961,336**	**3,231,653**	**3,503,414**	**3,776,658**	**4,051,421**	**6,790,810**	**6,962,788**	**7,139,110**
Investment	$	30,695,582										
Project IRR	%	**11.8%**										
Project cash flow	-30,695,582	2,158,706	2,424,898	2,692,430	2,961,336	3,231,653	3,503,414	3,776,658	4,051,421	6,790,810	6,962,788	7,139,110

2.3.3.2 Scenario 2 – Hybrid Charging of TES, Flue Gas with Electrical Topping

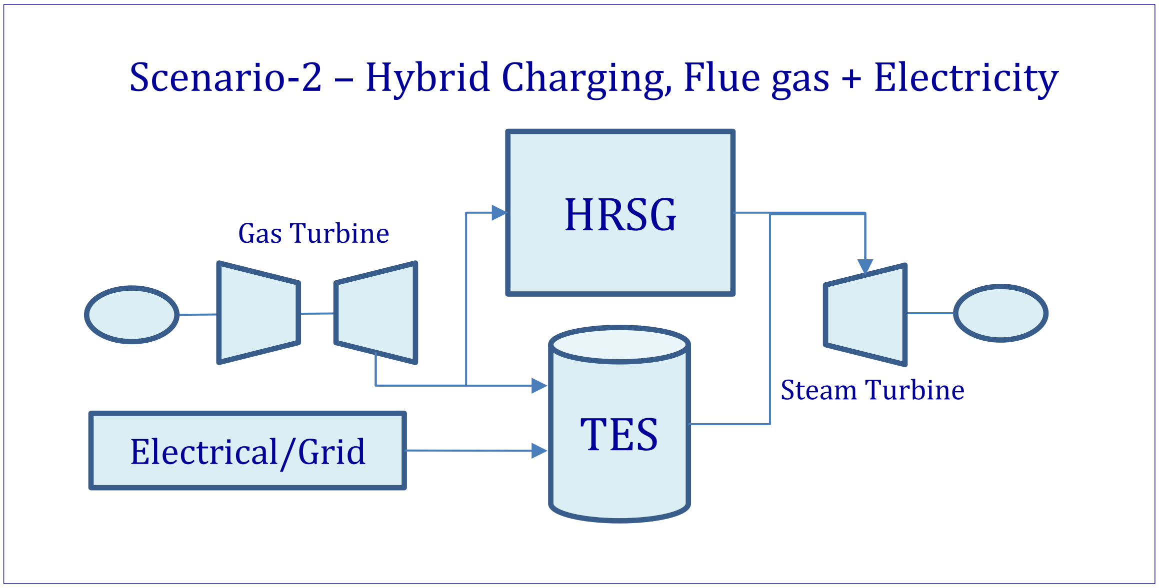


Figure 2-21. Scenario #2 – Hybrid Charging

Under scenario #2, the combustion turbine exhaust gas is extracted from the heat recovery steam generator (HRSG) to heat the bGen™ TES at 1,040°F (560°C), however there is also supplemental charging using grid electricity (see Figure 2-21). The bGen™ charging cycle would occur primarily during off-peak periods when power prices are low and/or the Facility is operating in turndown mode. Utilizing the embedded capability for electricity conversion to high temperature heat, additional charging takes place during off-peak hours using local produced electricity or electricity from the Grid. When charging from Grid and when available, the cycle can consume renewable electricity. It is assumed that the share of renewable electricity on Grid will grow in future years. During periods of premium power prices (day ahead or real-time prices), the discharge cycle will be activated by flowing feedwater through the hot bGen™ media causing the feedwater to flash to high-pressure steam at 1,827 psi, and 1,040°F (126 bar, 560°C) that would be combined with steam flowing from the HRSG and admitted into the steam turbine to produce additional electric power.

The bGen™ charge and discharge cycles, from both the thermal and the electrical sources create a device that stores low-value, off-peak energy and re-injects that energy into the facility steam cycle to boost steam turbine generator ("STG") during periods of high electricity demand/prices. Charging flue gases comes at the cost of reduced electricity output in the STG.

The proportion of flue gases extracted for charging the TES is calculated according to the installed TES size, 200MWh thermal in the current project analysis. As this scenario assumes a hybrid charging mode, the analysis includes 80% charging of the TES capacity from the thermal CT flue gases, and 20% charging from the electrical source. The ratio of electricity used for charging is assumed to grow along with the renewable energy penetration on the Grid. The analysis is based on 4 hours of charging and 4 hours of discharging. There is no requirement for continuous discharging or charging. Thermal charging or electrical charging time slots can be asynchronous. The additional generation of the steam turbine is considered incremental to the current plant generation due to the flexibility of discharge in a non-continuous mode and the low number of discharging hours – 4 hours.

The incremental annual generation resulting from the bGen™ TES system can reach 35,000 MWh. Using a simple assumption of 1 ton of CO_2 per 5 MWh electricity production, while working with a hybrid mode of 20% renewable Grid electrical charging, there will be an annual reduction of 1000 tons of CO_2. When available and 80% renewable electrical charging is used, annual emissions reduction will total to approximately 4000 tons of carbon.

Heat Balance and Process Flow Diagram

The Heat Balance shown in Figure 2-22 represents the hybrid mode option, using flue gas and electricity for charging. Electricity is converted to high temperature heat inside the TES unit using the embedded conversion capability. Discharging is performed using generated steam that is supplied to the steam turbine.

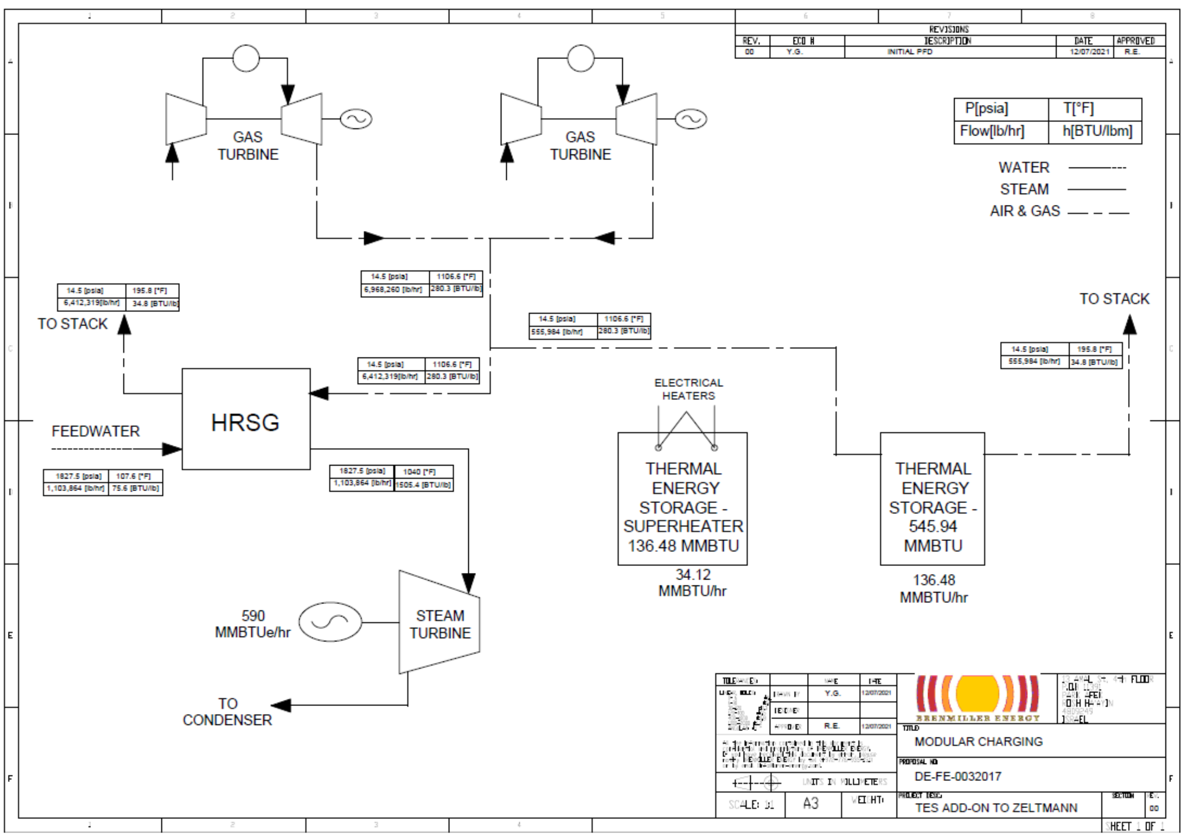


Figure 2-22. Scenario #2 – Hybrid Charging – Heat Balance

Additional analysis for this scenario can be found in the PFD shown in Figure 2-23.

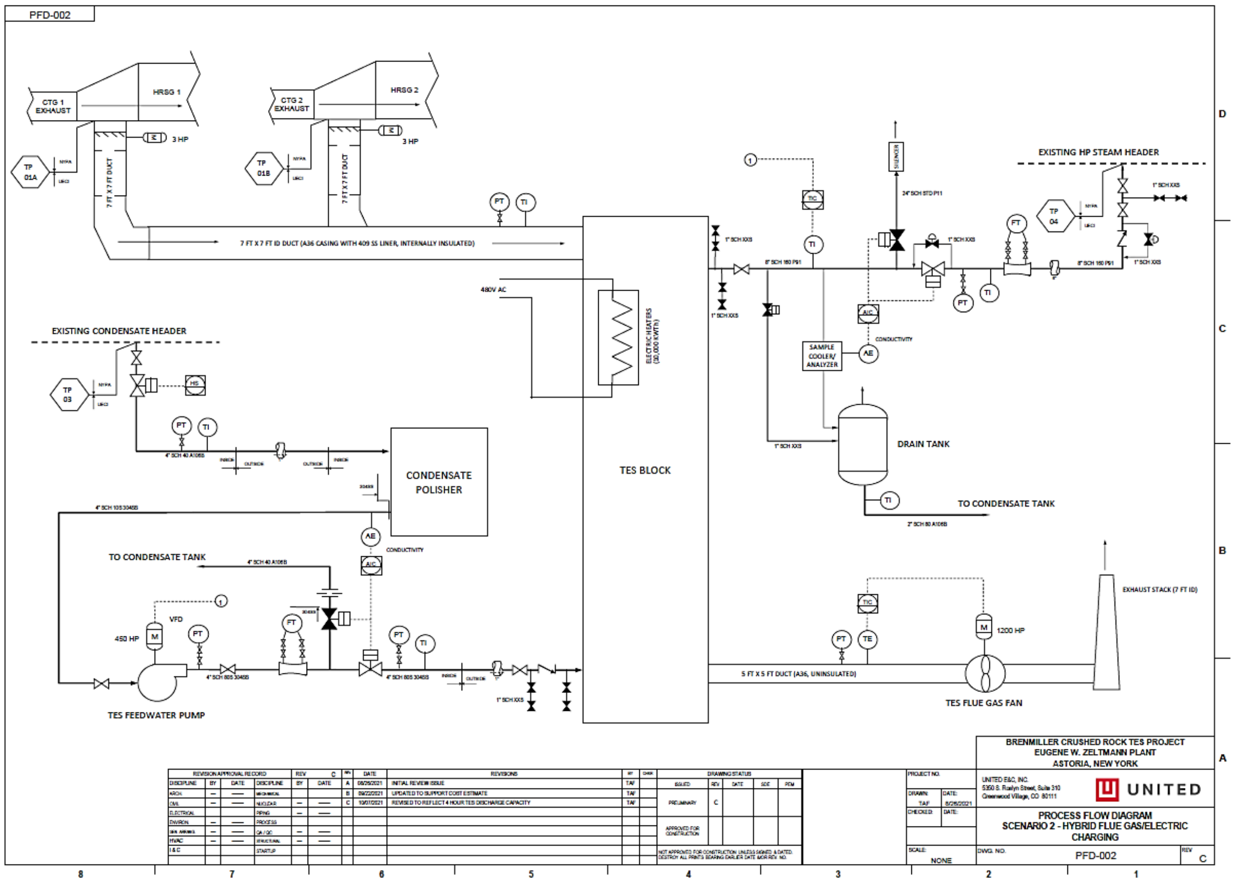


Figure 2-23. Scenario #2 – PFD

Performance Analysis and Financial Results

Using this hybrid configuration, along with bGen™ at 200MWh thermal capacity, Table 2-13 outlines the incremental generation of the TES.

Table 2-13. Key Charging and Discharging Energy Flows

Energy Flow	Charging	Discharging
CT exhaust gas at 1,040°F (560°C)	555,984 lb/hr	
Off-Peak Loss of STG Output	15.04 MW	
Off-Peak Charge from Electricity	3.76 MW	
Additional Steam Flow to STG		113,289 lb/hr
On-Peak Gain in STG Output		17.8 MW

The bGen™ TES system is sized to provide 4 hours of discharge at the rated discharge steam flow and electric output. In the NYISO market, energy storage resources are eligible to receive different levels of capacity credits at discharge duration periods from 2 to 8+ hours.

The following potential revenue streams are valid for this scenario energy calculation:

1. Energy Arbitrage based on historical real time prices
2. Additional margin for optimization of the Day Ahead prices with the real time prices
3. Ancillary services
4. Margins resulting from the penetration of renewables and carbon credits prices
5. Capacity payments for a storage system in the NYISO arena, last guidelines

Values of these revenue streams are presented in Table 2-14, for 2023. The Cash Flow Analysis will assume the development of each of the streams for future years.

Table 2-14. Potential Energy Arbitrage and Capacity Value of bGen™ Storage

Sources of Increased Value of Storage (2023)	Energy Margin $/kW-mo
Deployment based on historical RT prices (4-hr storage)	$4.17
Combination with DA activity + Overall optimization	$1.58
Ancillary services	$0.26
Renewable's penetration, less carbon in off-peak prices	$0.50
Capacity Revenues (Net of ICAP/UCAP and derating factors)	$5.13
Total Energy Margin + Capacity Payment	**11.64**

Table 2-15 presents the calculated investment cost for this scenario. The next stages of Pre-FEED and a detailed design will prepare more accurate calculations. The detailed design can optimize the cost. Larger and multiple installations have the potential to reduce the required investment.

Table 2-15. Required Investment for Scenario #2

Configuration main blocks – Cost	$ M
200MWh bGen™ Storage	$9.0
BOP Connection and Commissioning	$22.4
Total Cost	**$31.4**

It is assumed that the existing operational team at the Zeltmann plant will take over the operation of the TES system at no additional cost. Additional maintenance costs are estimated to be $258,000.

The cash flow analysis and IRR calculation for this scenario are shown in Tables 2-16 and 2-17.

Table 2-16. Project IRR – Scenario #2 - Source of charging energy: Hybrid Charging

		2023	2033
Operating Parameter			
Power Gen capability	kW	17,800	17,800
Electric storage capability	MWh	71.2	71.2
Derated/Adjusted capacity	kW	15,120	15,120
Assumed cycles per day	cycles/day	1.5	1.5
Selling hours	%	1,971	1,971
Annual generation	MWh	35,084	35,084
Hybrid electrical charging		20%	55%
Revenues/Margins			
Real time margin	$/KW/mo	4.17	9.71
Adder for DA and optimization	$/KW/mo	1.58	2.02
Inc. volatility + Renewables + CO2	$/KW/mo	0.5	8.41
Ancillary services	$/KW/mo	0.26	0.33
Capacity price	$/KW/mo	5.13	6.57
Total revenues	**$/KW/mo**	**11.64**	**27.04**
Anuual revenues			
Real time margin	$/yr	891,196	2,074,091
Adder for DA and optimization	$/yr	337,488	432,013
Inc. volatility + Renewables + CO2	$/yr	106,800	1,795,308
Ancillary services	$/yr	55,536	71,091
Capacity price	$/yr	930,787	1,191,486
Total revenues	**$/KW/mo**	**2,321,808**	**5,563,989**
Operating cost			
Variable operating cost	$/yr	29,237	35,640
Fixed operating cost	$/yr	229,500	279,759
Net cash flow	$/yr	**2,063,071**	**5,248,590**
Investment	$	31,387,020	
Project IRR	%	**12.5%**	

Table 2-17. Cash Flow Analysis – Scenario #2

Source of charging energy: Hybrid Exhaust gas + Electricity												
		2023	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2050**	**2051**	**2052**
Operating Parameter												
Power Gen capability	kW	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800
Electric storage capability	MWh	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2
Derated/Adjusted capacity	kW	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120
Assumed cycles per day	cycles/day	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Selling hours	%	1,971	1,971	1,971	1,971	1,971	1,971	1,971	1,971	1,971	1,971	1,971
Annual generation	MWh	35,084	35,084	35,084	35,084	35,084	35,084	35,084	35,084	35,084	35,084	35,084
Hybrid electrical charging		20%	22%	24%	26%	29%	32%	35%	40%	85%	85%	85%
Revenues/Margins												
Real time margin	$/KW/mo	4.17	4.45	4.76	5.11	5.52	5.99	6.51	7.17	12.24	12.28	12.31
Adder for DA and optimization	$/KW/mo	1.58	1.62	1.66	1.70	1.74	1.79	1.83	1.88	3.08	3.15	3.23
Inc. volatility + Renewables + CO2	$/KW/mo	0.5	1.5	2.5	3.5	4.5	5.5	6.5	7.5	12.79	13.11	13.44
Ancillary services	$/KW/mo	0.26	0.27	0.27	0.28	0.29	0.29	0.30	0.31	0.51	0.52	0.53
Capacity price	$/KW/mo	5.13	5.26	5.39	5.52	5.66	5.80	5.95	6.10	9.99	10.24	10.50
Total revenues	**$/KW/mo**	**11.64**	**13.09**	**14.58**	**16.12**	**17.72**	**19.37**	**21.09**	**22.95**	**38.61**	**39.30**	**40.01**
Anuual revenues												
Real time margin	$/yr	891,196	949,911	1,017,023	1,092,507	1,179,446	1,278,615	1,389,966	1,531,365	2,615,218	2,622,426	2,629,814
Adder for DA and optimization	$/yr	337,488	345,925	354,573	363,438	372,524	381,837	391,383	401,167	657,359	673,793	690,638
Inc. volatility + Renewables + CO2	$/yr	106,800	320,400	534,000	747,600	961,200	1,174,800	1,388,400	1,602,000	2,731,773	2,800,068	2,870,069
Ancillary services	$/yr	55,536	56,924	58,348	59,806	61,301	62,834	64,405	66,015	108,173	110,877	113,649
Capacity price	$/yr	930,787	954,057	977,908	1,002,356	1,027,415	1,053,100	1,079,428	1,106,413	1,812,987	1,858,312	1,904,770
Total revenues	**$/KW/mo**	**2,321,808**	**2,627,218**	**2,941,853**	**3,265,707**	**3,601,886**	**3,951,186**	**4,313,581**	**4,706,960**	**7,925,511**	**8,065,476**	**8,208,941**
Operating cost												
Variable operating cost	$/yr	29,237	29,822	30,418	31,027	31,647	32,280	32,926	33,584	49,904	50,902	51,920
Fixed operating cost	$/yr	229,500	234,090	238,772	243,547	248,418	253,387	258,454	263,623	391,730	399,565	407,556
Net cash flow	$/yr	**2,063,071**	**2,363,306**	**2,672,663**	**2,991,133**	**3,321,820**	**3,665,519**	**4,022,201**	**4,409,753**	**7,483,876**	**7,615,009**	**7,749,464**
Investment	$	31,387,020										
Project IRR	%	**12.5%**										
Project cash flow	-31,387,020	2,063,071	2,363,306	2,672,663	2,991,133	3,321,820	3,665,519	4,022,201	4,409,753	7,483,876	7,615,009	7,749,464

2.3.3.3 Scenario 3 – Electrical Charging of TES

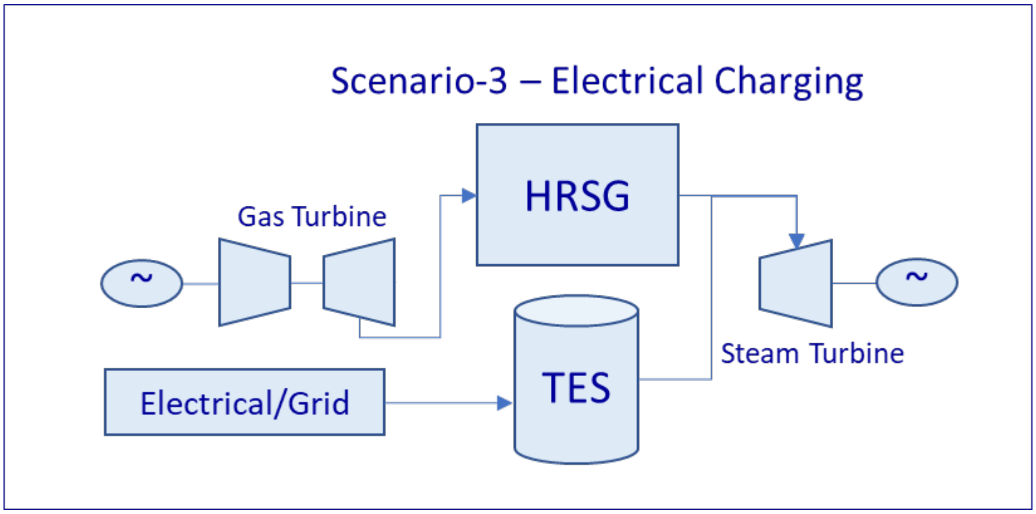


Figure 2-24. Scenario #3 – Electrical Charging

Scenario #3 includes charging of the bGen™ unit using exclusively electrical sources, locally produced at the Facility or provided from the Grid (see Figure 2-24). The bGen™ TES charging cycle would occur primarily during off-peak periods when power prices are low. Utilizing the inherent conversion capability, electricity is internally converted to high temperature heat that is stored in the TES unit. According the level of renewables penetration, this scenario may support a gradual shift to renewables at an existing NGCC plant. The bGen™ size has been selected as 200MWh thermal, as in all other scenarios. During periods of premium power prices (day ahead or real-time prices), a discharge cycle will be activated by flowing feedwater through the hot bGen™ media causing the feedwater to flash to high-pressure steam at 1,827 psi, and 1,040°F (126 bar, 560°C), which would be combined with steam flowing from the HRSG and admitted into the steam turbine to produce additional electric power.

The advantage of this scenario increases with increased renewables penetration in the generation market. In key regions of the US, including states such as California, Texas, and Florida, where there is a growing share of electricity produced from renewable sources, such as solar and wind, there exists the opportunity to charge the TES during the night with low or even negative value of the grid-supplied electricity. With the potential of additional income streams from the reduction in GHG emissions, through carbon credits or reduced carbon tax, this advantage is growing.

The bGen™ system enables the charging and discharging of the TES unit incrementally over multiple charging periods, until full capacity is achieved, not only in one continuous process. In addition, charging and discharging can take place in parallel, or at totally different times.

When the TES charging for this scenario is performed using renewable energy from Grid, an annual reduction of 7000 tons of carbon can be achieved, compared to a case where equivalent production was the result of charging the TES from locally produced electricity from natural gas fuel, or from non-renewable electricity from the grid.

Heat Balance and Process Flow Diagram

The Heat Balance shown in Figure 2-25 represents the electrical charging scenario. Electricity is converted to high temperature heat inside the TES unit using the embedded conversion capability.

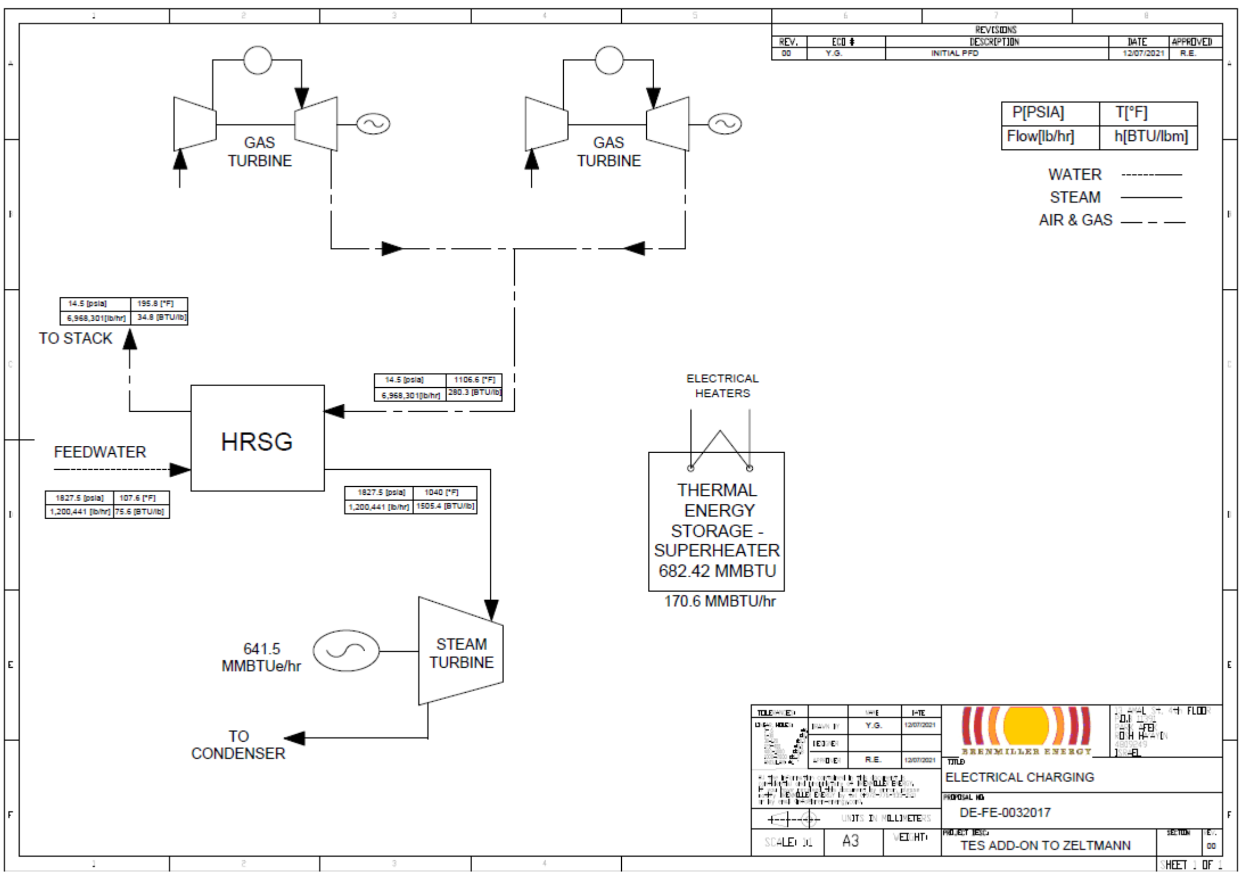


Figure 2-25. Scenario #3 – Electrical Charging – Heat Balance

Additional analysis results of this scenario are included in the PFD, as shown in Figure 2-26:

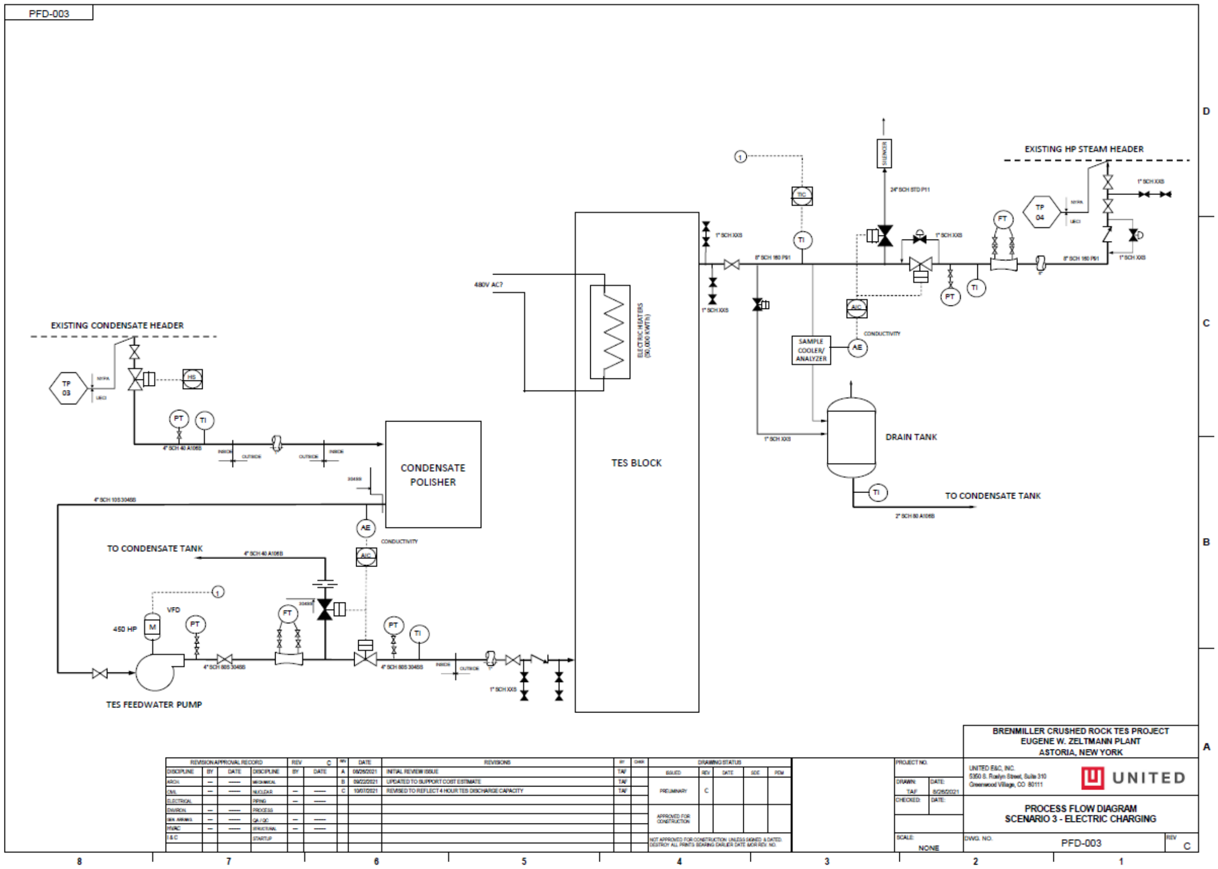


Figure 2-26. Scenario #3 – Balance of Plant PFD

Performance Analysis and Financial Results

The bGen^{TM} system is sized for 200MWh thermal to provide 4 hours of discharge operation at the rated discharge steam flow and electric output, resulting in a 17.8 MW incremental generation.

The following potential streams of revenue are considered valid for this scenario calculation:

1. Energy Arbitrage based on historical real time prices
2. Additional margin for optimization of the Day Ahead prices with the real time prices
3. Ancillary services
4. Margins resulting from the penetration of renewables and carbon credits prices
5. Capacity payments for a storage system in the NYISO arena, last guidelines

Table 2-18 summarizes the values of these potential streams of revenues, calculated for 2023. Cash Flow Analysis will assume development in each of these margins.

Table 2-18. Potential Energy Arbitrage and Capacity Value of bGen™ Storage

Sources of Increased Value of Storage (2023)	Energy Margin $/kW-mo
Deployment based on historical RT prices (4-hr storage)	$2.38
Combination with DA activity + Overall optimization	$1.58
Ancillary services	$0.26
Renewable's penetration, less carbon in off-peak prices	$0.50
Capacity Revenues (Net of ICAP/UCAP and derating factors)	$5.13
Total Energy Margin + Capacity Payment	**9.85**

Table 2-19 details the required investment for this scenario. Future detailed design calculations will give more accurate calculations and address possible cost reductions.

Table 2-19. Required Investment for Scenario #3

Configuration main blocks – Cost	$ M
200MWh bGen™ Storage	$8.0
BOP Connection and Commissioning	$18.5
Total Cost	**$26.5**

As in other scenarios, it is assumed that the existing operations team at the Zeltmann plant will take control of the TES operation at no additional cost. Additional maintenance cost is estimated to be $258,000.

Tables 2-20 and 2-21 include the calculated Cash Flow and IRR analysis for scenario #3.

Table 2-20. Project IRR – Scenario #3 – Source of charging energy: Local or Grid Electricity

		2023	2033
Operating Parameter			
Power Gen capability	kW	17,800	17,800
Electric storage capability	MWh	71.2	71.2
Derated/Adjusted capacity	kW	15,120	15,120
Assumed cycles per day	cycles/day	1.5	1.5
Selling hours	%	1,971	1,971
Annual generation	MWh	35,084	35,084
Electrical charging price	$/MWh	10	-20
Revenues/Margins			
Real time margin	$/KW/mo	2.38	12.82
Adder for DA and optimization	$/KW/mo	1.58	2.02
Inc. volatility + Renewables + CO2	$/KW/mo	0.5	8.41
Ancillary services	$/KW/mo	0.26	0.33
Capacity price	$/KW/mo	5.13	6.57
Total revenues	**$/KW/mo**	**9.85**	**30.14**
Anuual revenues			
Real time margin	$/yr	508,654	2,737,524
Adder for DA and optimization	$/yr	337,488	432,013
Inc. volatility + Renewables + CO2	$/yr	106,800	1,795,308
Ancillary services	$/yr	55,536	71,091
Capacity price	$/yr	930,787	1,191,486
Total revenues	**$/KW/mo**	**1,939,265**	**6,227,422**
Operating cost			
Variable operating cost	$/yr	29,237	35,640
Fixed operating cost	$/yr	229,500	279,759
Net cash flow	$/yr	**1,680,528**	**5,912,023**
Investment	$	26,511,748	
Project IRR	%	**14.8%**	

Table 2-21.Cash Flow Analysis – Scenario #3

Source of charging energy: Electricity												
		2023	2024	2025	2026	2027	2028	2029	2030	2050	2051	2052
Operating Parameter												
Power Gen capability	kW	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800
Electric storage capability	MWh	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2
Derated/Adjusted capacity	kW	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120
Assumed cycles per day	cycles/day	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Selling hours	%	1,971	1,971	1,971	1,971	1,971	1,971	1,971	1,971	1,971	1,971	1,971
Annual generation	MWh	35,084	35,084	35,084	35,084	35,084	35,084	35,084	35,084	35,084	35,084	35,084
Electrical charging price	$/MWh	10	7	4	1	-2	-5	-8	-11	-20	-20	-20
Revenues/Margins												
Real time margin	$/KW/mo	2.38	3.42	4.47	5.51	6.56	7.60	8.64	9.69	12.82	12.82	12.82
Adder for DA and optimization	$/KW/mo	1.58	1.62	1.66	1.70	1.74	1.79	1.83	1.88	3.08	3.15	3.23
Inc. volatility + Renewables + CO2	$/KW/mo	0.5	1.5	2.5	3.5	4.5	5.5	6.5	7.5	12.79	13.11	13.44
Ancillary services	$/KW/mo	0.26	0.27	0.27	0.28	0.29	0.29	0.30	0.31	0.51	0.52	0.53
Capacity price	$/KW/mo	5.13	5.26	5.39	5.52	5.66	5.80	5.95	6.10	9.99	10.24	10.50
Total revenues	**$/KW/mo**	**9.85**	**12.07**	**14.29**	**16.52**	**18.75**	**20.98**	**23.23**	**25.47**	**39.18**	**39.84**	**40.52**
Anuual revenues												
Real time margin	$/yr	508,654	731,541	954,428	1,177,315	1,400,202	1,623,089	1,845,976	2,068,863	2,737,524	2,737,524	2,737,524
Adder for DA and optimization	$/yr	337,488	345,925	354,573	363,438	372,524	381,837	391,383	401,167	657,359	673,793	690,638
Inc. volatility + Renewables + CO2	$/yr	106,800	320,400	534,000	747,600	961,200	1,174,800	1,388,400	1,602,000	2,731,773	2,800,068	2,870,069
Ancillary services	$/yr	55,536	56,924	58,348	59,806	61,301	62,834	64,405	66,015	108,173	110,877	113,649
Capacity price	$/yr	930,787	954,057	977,908	1,002,356	1,027,415	1,053,100	1,079,428	1,106,413	1,812,987	1,858,312	1,904,770
Total revenues	**$/KW/mo**	**1,939,265**	**2,408,847**	**2,879,257**	**3,350,515**	**3,822,642**	**4,295,660**	**4,769,591**	**5,244,458**	**8,047,817**	**8,180,574**	**8,316,650**
Operating cost												
Variable operating cost	$/yr	29,237	29,822	30,418	31,027	31,647	32,280	32,926	33,584	49,904	50,902	51,920
Fixed operating cost	$/yr	229,500	234,090	238,772	243,547	248,418	253,387	258,454	263,623	391,730	399,565	407,556
Net cash flow	$/yr	**1,680,528**	**2,144,936**	**2,610,067**	**3,075,941**	**3,542,576**	**4,009,993**	**4,478,211**	**4,947,251**	**7,606,182**	**7,730,106**	**7,857,173**
Investment	$	26,511,748										
Project IRR	%	**14.8%**										
Project cash flow	-26,511,748	1,680,528	2,144,936	2,610,067	3,075,941	3,542,576	4,009,993	4,478,211	4,947,251	7,606,182	7,730,106	7,857,173

2.3.3.4 Scenario 4 – Hybrid Charging of TES, Steam with Electrical Topping

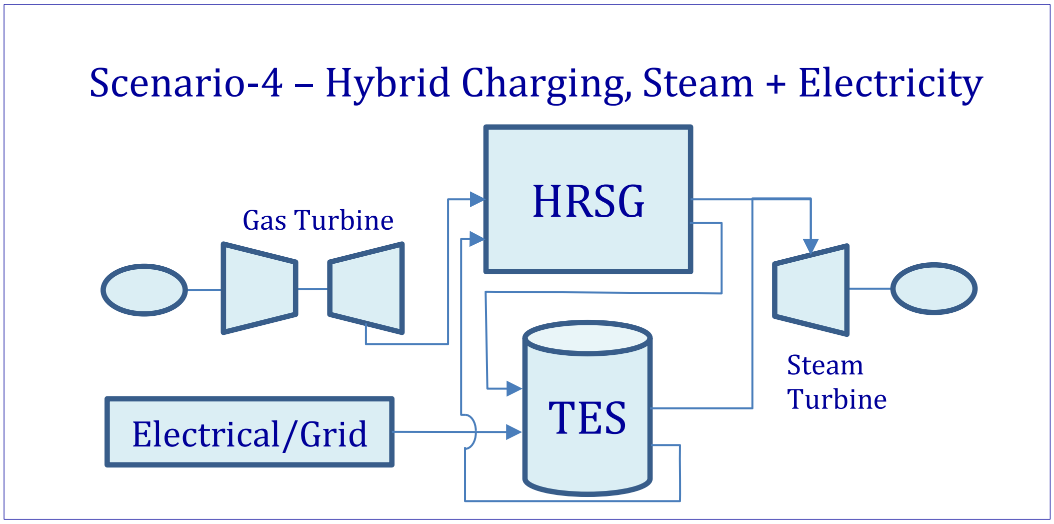


Figure 2-27. Scenario #4 – Hybrid Charging, Steam + Electricity

Under scenario #4, shown in Figure 2-27, superheated steam is taken from the heat recovery steam generator (HRSG) output to heat the bGen™ TES at 1,040°F (560°C). Residual steam exits the bGen™ TES during the charging cycle at 623°F (328°C) and is sent back to the HRSG for reuse at the steam generation cycle. To enable the bGen™ TES to produce steam at the required conditions for the steam turbine, out of the internal collected energy, the TES is topped with supplemental charging using the grid electricity. The bGen™ charging cycle would occur primarily during off-peak periods, when power prices are low and/or the facility is operating in turndown mode. Utilizing the embedded capability for electricity conversion to high temperature heat, additional charging takes place during off-peak hours using local produced electricity or electricity from the grid. When charging from grid and when available, the cycle can use renewable electricity. It is assumed that the share of renewable electricity on grid will grow in future years. During periods of premium power prices (day ahead or real-time prices), the discharge cycle will be activated by flowing feedwater through the hot bGen™ media causing the feedwater to flash to high-pressure steam at 1,827 psi, and 1,040°F (126 bar, 560°C) that would be combined with steam flowing from the HRSG and admitted into the steam turbine to produce additional electric power.

The bGen™ ability to charge and discharge from both the thermal and the electrical sources creates a device that stores low-value, off-peak energy and re-injects that energy into the facility steam cycle to boost steam turbine generator ("STG") during periods of high electricity demand/prices. Charging with steam comes at the cost of reduced electricity output in the STG.

The proportion of steam extracted for charging the TES is calculated according to the installed TES size, 200MWh thermal in the current project analysis. As this scenario assumes a hybrid charging mode, the analysis includes 75% charging of the TES capacity from the thermal HTSG steam, and 25% charging from the electrical source. The ratio of electricity used for charging is assumed to grow along with the renewable energy penetration on the grid. The analysis is based on 4 hours of charging and 4 hours of discharging. There is no requirement for continuous discharging or charging. Thermal charging or electrical charging time slots can be asynchronous. The additional generation of the steam turbine is considered incremental to the current plant generation due to the flexibility of discharge in a non-continuous mode and the low number of discharging hours – 4 hours.

For optimization of the required CAPEX investment in this scenario, the scenario has been designed to enable only thermal charging or discharging at the same time. No parallel charging and discharging of superheated steam. Such a design enables multiple cycles per day, depending on the selected TES size. Electricity can be used for charging the TES at any time, during charging or discharging and especially at off peak time slots.

The incremental annual generation resulting from the bGen™ TES system can reach 35,000 MWh. Using a simple assumption of 1 ton of CO_2 per 5 MWh electricity production, while working with a hybrid mode of 25% renewable Grid electrical charging, there will be an annual reduction of 1000 tons of CO_2. When available and 75% renewable electrical charging is used, annual emissions reduction will total approximately 4000 tons of carbon.

Heat Balance and Process Flow Diagram

The Heat Balance shown in Figure 2-28 represents the hybrid charging using both HRSG superheated steam and converted electricity from the grid. The conversion of electricity to high temperature heat inside the TES unit is using the embedded conversion capability. The Heat Balance shows the return path of lower temperature steam as well to the HRSG.

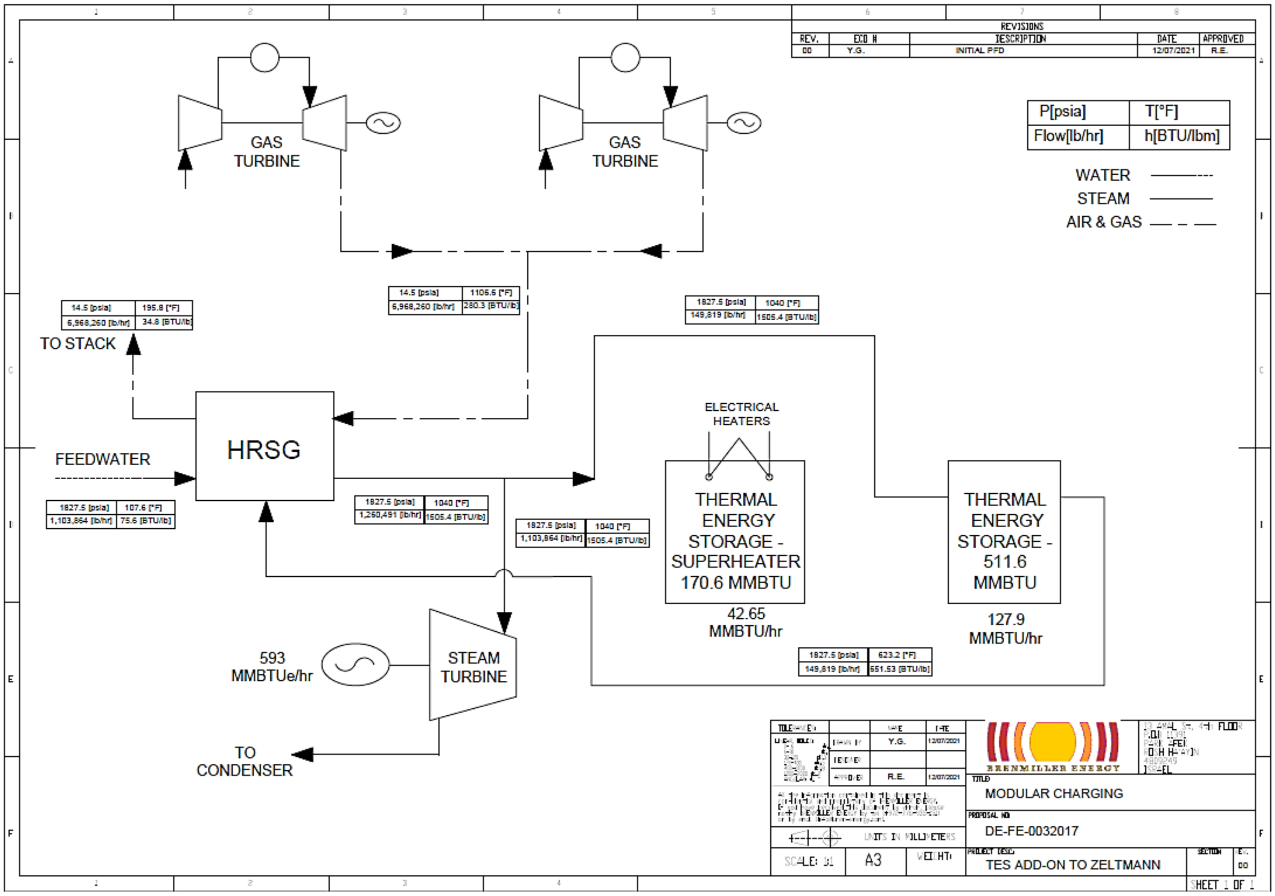


Figure 2-28. Scenario #4 – Steam Hybrid Charging – Heat Balance

Additional analysis results of this scenario are included in the PFD, as shown in Figure 2-29:

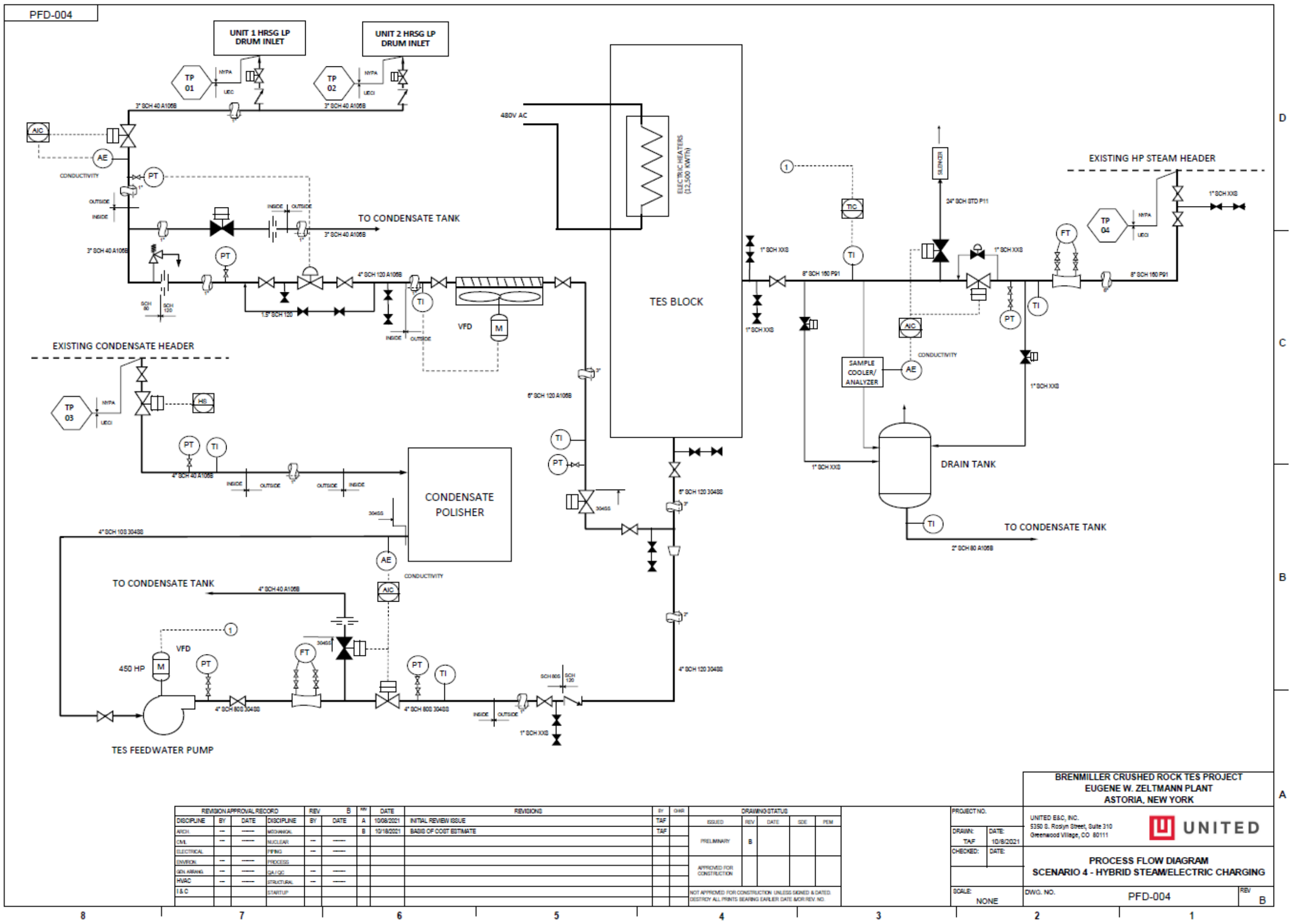


Figure 2-29. Scenario #4 –PFD

Performance Analysis and Financial Results

The bGen™ TES system is sized to provide 4 hours of discharge at the rated discharge steam flow and electric output. In the NYISO market, energy storage resources are eligible to receive different levels of capacity credits at discharge duration periods from 2 to 8+ hours.

The following potential revenue streams are valid for this scenario's energy calculation:

1. Energy arbitrage based on historical real time prices
2. Additional margin for optimization of the Day Ahead (DA) prices with the real time prices
3. Ancillary services
4. Margins resulting from the penetration of renewables and carbon credits prices

5. Capacity payments for a storage system in the NYISO arena, last guidelines

Values of these revenue streams are presented in Table 2-22, for 2023. The Cash Flow Analysis will assume the development of each of the streams for future years.

Table 2-22. Potential Energy Arbitrage and Capacity Value of bGen™ Storage

Sources of Increased Value of Storage (2023)	**Energy Margin $/kW-mo**
Deployment based on historical RT prices (4-hr storage)	$4.06
Combination with DA activity + Overall optimization	$1.58
Ancillary services	$0.26
Renewable's penetration, less carbon in off-peak prices	$0.50
Capacity Revenues (Net of ICAP/UCAP and derating factors)	$5.13
Total Energy Margin + Capacity Payment	**11.53**

Table 2-23 details the required investment for this scenario. Future detailed design calculations will give more accurate calculations and address possible cost reductions.

Table 2-23. Required Investment for Scenario #3

Configuration main blocks – Cost	**$ M**
200MWh bGen™ Storage	$9.0
BOP Connection and Commissioning	$13.3
Total Cost	**$22.3**

As in other scenarios, it is assumed that the existing operations team at the Zeltmann plant will take control of the TES operation at no additional cost. Additional maintenance cost is estimated to be $258,000.

Tables 2-24 and 2-25 include the calculated Cash Flow and IRR analysis for scenario #4.

Table 2-24. Project IRR – Scenario #4 – Source of charging energy: Steam and Electricity

		2023	2033
Operating Parameter			
Power Gen capability	kW	17,800	17,800
Electric storage capability	MWh	71.2	71.2
Derated/Adjusted capacity	kW	15,120	15,120
Assumed cycles per day	cycles/day	1.5	1.5
Selling hours	%	1,971	1,971
Annual generation	MWh	35,084	35,084
Hybrid electrical charging		25%	60%
Revenues/Margins			
Real time margin	$/KW/mo	4.06	10.06
Adder for DA and optimization	$/KW/mo	1.58	2.02
Inc. volatility + Renewables + CO2	$/KW/mo	0.5	8.41
Ancillary services	$/KW/mo	0.26	0.33
Capacity price	$/KW/mo	5.13	6.57
Total revenues	**$/KW/mo**	**11.53**	**27.38**
Anuual revenues			
Real time margin	$/yr	867,288	2,147,806
Adder for DA and optimization	$/yr	337,488	432,013
Inc. volatility + Renewables + CO2	$/yr	106,800	1,795,308
Ancillary services	$/yr	55,536	71,091
Capacity price	$/yr	930,787	1,191,486
Total revenues	**$/KW/mo**	**2,297,899**	**5,637,704**
Operating cost			
Variable operating cost	$/yr	29,237	35,640
Fixed operating cost	$/yr	229,500	279,759
Net cash flow	$/yr	**2,039,162**	**5,322,305**
Investment	$	22,261,326	
Project IRR	%	**16.6%**	

Table 2-25.Cash Flow Analysis – Scenario #4

		2023	2024	2025	2026	2027	2028	2029	2030	2050	2051	2052
Operating Parameter												
Power Gen capability	kW	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800
Electric storage capability	MWh	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2
Derated/Adjusted capacity	kW	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120
Assumed cycles per day	cycles/day	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Selling hours	%	1,971	1,971	1,971	1,971	1,971	1,971	1,971	1,971	1,971	1,971	1,971
Annual generation	MWh	35,084	35,084	35,084	35,084	35,084	35,084	35,084	35,084	35,084	35,084	35,084
Hybrid electrical charging		25%	27%	29%	31%	34%	37%	40%	45%	90%	90%	90%
Revenues/Margins												
Real time margin	$/KW/mo	4.06	4.38	4.74	5.14	5.59	6.10	6.67	7.38	12.43	12.46	12.48
Adder for DA and optimization	$/KW/mo	1.58	1.62	1.66	1.70	1.74	1.79	1.83	1.88	3.08	3.15	3.23
Inc. volatility + Renewables + CO2	$/KW/mo	0.5	1.5	2.5	3.5	4.5	5.5	6.5	7.5	12.79	13.11	13.44
Ancillary services	$/KW/mo	0.26	0.27	0.27	0.28	0.29	0.29	0.30	0.31	0.51	0.52	0.53
Capacity price	$/KW/mo	5.13	5.26	5.39	5.52	5.66	5.80	5.95	6.10	9.99	10.24	10.50
Total revenues	**$/KW/mo**	**11.53**	**13.03**	**14.56**	**16.15**	**17.79**	**19.49**	**21.25**	**23.16**	**38.80**	**39.48**	**40.18**
Anuual revenues												
Real time margin	$/yr	867,288	935,913	1,012,905	1,098,238	1,194,992	1,303,944	1,425,044	1,576,156	2,655,986	2,660,792	2,665,717
Adder for DA and optimization	$/yr	337,488	345,925	354,573	363,438	372,524	381,837	391,383	401,167	657,359	673,793	690,638
Inc. volatility + Renewables + CO2	$/yr	106,800	320,400	534,000	747,600	961,200	1,174,800	1,388,400	1,602,000	2,731,773	2,800,068	2,870,069
Ancillary services	$/yr	55,536	56,924	58,348	59,806	61,301	62,834	64,405	66,015	108,173	110,877	113,649
Capacity price	$/yr	930,787	954,057	977,908	1,002,356	1,027,415	1,053,100	1,079,428	1,106,413	1,812,987	1,858,312	1,904,770
Total revenues	**$/KW/mo**	**2,297,899**	**2,613,220**	**2,937,734**	**3,271,437**	**3,617,432**	**3,976,515**	**4,348,659**	**4,751,752**	**7,966,279**	**8,103,842**	**8,244,844**
Operating cost												
Variable operating cost	$/yr	29,237	29,822	30,418	31,027	31,647	32,280	32,926	33,584	49,904	50,902	51,920
Fixed operating cost	$/yr	229,500	234,090	238,772	243,547	248,418	253,387	258,454	263,623	391,730	399,565	407,556
Net cash flow	$/yr	**2,039,162**	**2,349,308**	**2,668,544**	**2,996,864**	**3,337,367**	**3,690,848**	**4,057,279**	**4,454,544**	**7,524,645**	**7,653,375**	**7,785,367**
Investment	$	22,261,326										
Project IRR	%	**16.6%**										
Project cash flow	-22,261,326	2,039,162	2,349,308	2,668,544	2,996,864	3,337,367	3,690,848	4,057,279	4,454,544	7,524,645	7,653,375	7,785,367

2.3.4 Non-Financial Benefits

In addition to the presented financial advantages of integrating crushed-rock TES with an existing NGCC plant, such as Zeltmann, there are multiple benefits to the asset owner, to the grid and to the environment. These advantages may be described on a qualitative basis as follows:

1. **Readiness for Increased Renewable's Penetration** – In the NYISO area as in other regions in the United States, there are varying (and increasing) levels of renewables generation on the local grid. A full shift from fossil fuels to renewables is expected to take several years due to the continued economic attractiveness of natural gas fuel. The bGen^{TM} TES solution enables a gradual shift to the renewables, keeping previous advantages and gradually shifting to renewables for economical generation with emissions reduction.

2. **Extension of Existing Investments** – A significant investment has been made into existing NGCC plants. Utilizing a integrated crushed-rock TES can help to extend the viable lifetime of the existing NGCC plants through this gradual shift, while improving overall efficiency and supporting the VRE generation. The TES is a good fit for integration with the existing installed capital equipment in the plant. Integration of TES systems with existing fossil plans can provide an economically viable alternative to building new replacement generating assets.

3. **Carbon Emissions and Credits** – The Carbon credits market and in some places the Carbon tax are evolving and changing frequently. As Carbon regulations evolve, it may be expected that prices of Carbon would become a major factor in a power plant's

generation profile. The integrated TES allows the power plant to use an additional independent variable to be used in the plant optimization algorithm. This adds flexibility to the daily decision on generation and how to address emissions reductions and emissions payments through the added hybrid generation capability.

4. **Flexible Charging and Discharging** – The increases in variable renewable electricity generation can create a volatile market for electricity prices. The capability of the integrated crushed-rock TES to enable multiple cycles per day with no degradation of the storage media, long lifetime of the storage unit, together with the capability to charge or discharge independently and with no dependency, enables the flexibility needed to thrive in a market with increasing price volatility. The anticipated increased penetration of renewable generation will require multiple daily shutdowns or start-ups from existing fossil plants, with a potential loss of efficiency, if this is not managed using energy storage. TES provides the tool needed to effectively manage this volatility.

5. **Natural Gas Peaks and Constraints** – Natural gas supply is facing dynamic constraints with the need for capital equipment, and seasonal fuel price fluctuations. The installation of an integrated crushed-rock TES with an NGCC plant can help to manage these constraints by serving as a buffer to the high-cost peaks in the spot market for natural gas. This TES can provide a tool to help power plant owners to manage such peaks and reduce the needs for additional investments.

2.3.5 Scenarios Comparison Summary

Four crushed-rock TES scenarios were analyzed as part of this Conceptual Study. The associated costs and financial advantages for each of the scenarios were evaluated and compared. Results show that the thermal charging has high suitability for integration with existing NGCC plant equipment, while using the electricity as a topping mechanism. This thermal charging provides high flexibility in a market with increasing penetration of renewable generation. The scenarios that use partial or full electricity for charging show significant additional financial advantages, primarily through the potential for ancillary revenue streams. The projected revenue sources for the integrated TES system are shown in Figure 2-30. This shows the predicted economic impact of increased volatility and increasing carbon emissions costs in future years.

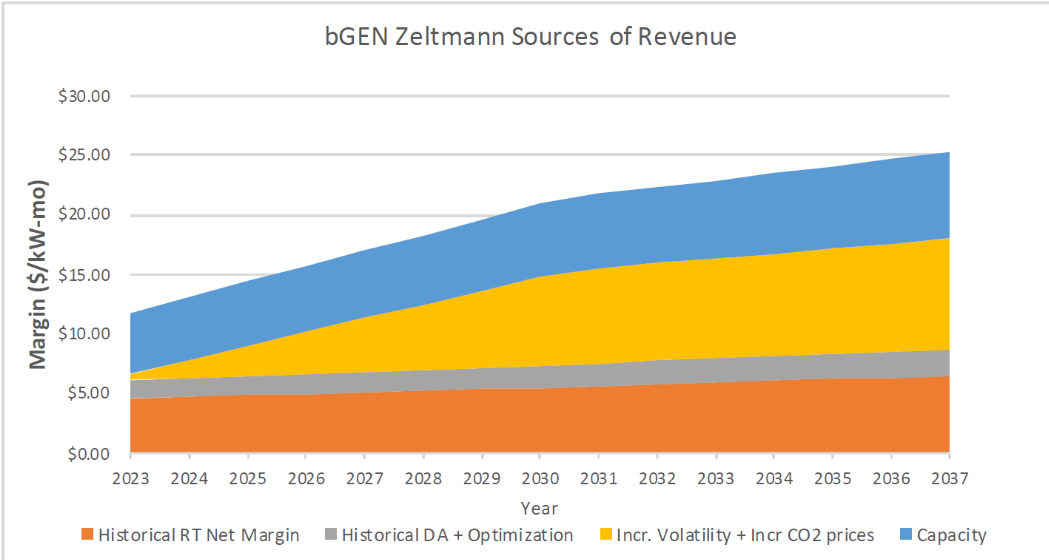


Figure 2-30. bGenTM Installation at Zeltmann – Predicted Revenue Sources

Looking ahead to the power generation mix in future years and recognizing that there are limitations on installation of new capital equipment, it is evident that the ideal scenarios must be ready for integration of renewable electricity from the grid. Preferred solutions will be the hybrid solutions which enable a gradual shift from thermal charging sources to electrical (from renewable) charging sources.

Looking at the financial results of each scenario, the complexity of implementation of each of the configurations in the different scenarios, the risk associated in the implementation of each scenario and the flexibility for future different penetration ratios of the renewables on the grid, **Scenario #4** is selected as the optimal solution. As previously described in this study, the following principles characterize this scenario:

- Charging the TES with superheated steam from HRSG
- Topping with partial electricity charging to enable high temperature steam output to ST
- Utilizing the residual low temperature steam during charging back to the HRSG
- Using the same piping for charging and discharging of steam (for cost reduction)
- Enabling charging with electricity at any given time
- Reaching an IRR of more than 16% at a site as Zeltmann with 200MWh of storage

2.4 Post-Project Plans

The work included in the current project plan is part of the effort needed to advance crushed-rock TES technology toward large-scale commercialization (TRL 9) by the 2030 target date. The next-step pilot would be the subsequent logical step after the currently defined work scope and would advance the technology from TRL 5 to TRL 6.

As part of this effort, the project is expected to assess potential local suppliers for main blocks of the system, potential local EPC companies for the installation challenges, final definition of required integration and commissioning procedures, finalizing the system documentation as training, operation, and maintenance. The overall control of the TES, as an integral part of the plant control will be one the challenges for the project Pre-FEED stage, for integration of the TES into the existing plant, both in defining the required algorithms and in allocating the local companies, capable of implementing these TES integration control algorithms and software. In preparation for commercialization and multiple installations of the TES in NGCC plants, the project team will assess the required maintenance capabilities, potential agreements with local maintenance companies and all logistic aspects of the TES installation and shipments to various locations in the US.

2.5 References

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2.6 Appendix – Technology Readiness Levels Defined by DOE

Table 2-26. Technology Readiness Level Definitions

Relative Level of Technology Development	Technology Readiness Level	TRL Definition	Description
System Operations	**TRL 9**	Actual system operated over the full range of expected mission conditions.	The technology is in its final form and operated under the full range of operating mission conditions. Examples include using the actual system with the full range of wastes in hot operations.
System Commissioning	**TRL 8**	Actual system completed and qualified through test and demonstration.	The technology has been proven to work in its final form and under expected conditions. In almost all cases, this TRL represents the end of true system development. Examples include developmental testing and evaluation of the system with actual waste in hot commissioning. Supporting information includes operational procedures that are virtually complete. An Operational Readiness Review (ORR) has been successfully completed prior to the start of hot testing.
	TRL 7	Full-scale, similar (prototypical) system demonstrated in relevant environment	This represents a major step up from TRL 6, requiring demonstration of an actual system prototype in a relevant environment. Examples include testing full-scale prototype in the field with a range of simulants in cold commissioning (1). Supporting information includes results from the full-scale testing and analysis of the differences between the test environment, and analysis of what the experimental results mean for the eventual operating system/environment. Final design is virtually complete.
Technology Demonstration	**TRL 6**	Engineering/pilot-scale, similar (prototypical) system validation in relevant environment	Engineering-scale models or prototypes are tested in a relevant environment. This represents a major step up in a technology's demonstrated readiness. Examples include testing an engineering scale prototypical system with a range of simulants.(1) Supporting information includes results from the engineering scale testing and analysis of the differences between the engineering scale, prototypical system/environment, and analysis of what the experimental results mean for the eventual operating system/environment. TRL 6 begins true engineering development of the technology as an operational system. The major difference between TRL 5 and 6 is the step up from laboratory scale to engineering scale and the determination of scaling factors that will enable design of the operating system. The prototype should be capable of performing all the functions that will be required of the operational system. The operating environment for the testing should closely represent the actual operating environment.
Technology Development	**TRL 5**	Laboratory scale, similar system validation in relevant environment	The basic technological components are integrated so that the system configuration is similar to (matches) the final application in almost all respects. Examples include testing a high-fidelity, laboratory scale system in a simulated environment with a range of simulants (1) and actual waste (2). Supporting information includes results from the laboratory scale testing, analysis of the differences between the laboratory and eventual operating system/environment, and analysis of what the experimental results mean for the eventual operating system/environment. The major difference between TRL 4 and 5 is the increase in the fidelity of the system and environment to the actual application. The system tested is almost prototypical.

Relative Level of Technology Development	Technology Readiness Level	TRL Definition	Description
Technology Development	**TRL 4**	Component and/or system validation in laboratory environment	The basic technological components are integrated to establish that the pieces will work together. This is relatively "low fidelity" compared with the eventual system. Examples include integration of ad hoc hardware in a laboratory and testing with a range of simulants and small-scale tests on actual waste (2). Supporting information includes the results of the integrated experiments and estimates of how the experimental components and experimental test results differ from the expected system performance goals. TRL 4-6 represent the bridge from scientific research to engineering. TRL 4 is the first step in determining whether the individual components will work together as a system. The laboratory system will probably be a mix of on hand equipment and a few special purpose components that may require special handling, calibration, or alignment to get them to function.
Research to Prove Feasibility	**TRL 3**	Analytical and experimental critical function and/or characteristic proof of concept	Active research and development (R&D) is initiated. This includes analytical studies and laboratory-scale studies to physically validate the analytical predictions of separate elements of the technology. Examples include components that are not yet integrated, or representative tested with simulants.(1) Supporting information includes results of laboratory tests performed to measure parameters of interest and comparison to analytical predictions for critical subsystems. At TRL 3 the work has moved beyond the paper phase to experimental work that verifies that the concept works as expected on simulants. Components of the technology are validated, but there is no attempt to integrate the components into a complete system. Modeling and simulation may be used to complement physical experiments.
Basic Technology Research	**TRL 2**	Technology concept and/or application formulated	Once basic principles are observed, practical applications can be invented. Applications are speculative, and there may be no proof or detailed analysis to support the assumptions. Examples are still limited to analytic studies. Supporting information includes publications or other references that outline the application being considered and that provide analysis to support the concept. The step up from TRL 1 to TRL 2 moves the ideas from pure to applied research. Most of the work is analytical or paper studies with the emphasis on understanding the science better. Experimental work is designed to corroborate the basic scientific observations made during TRL 1 work.
	TRL 1	Basic principles observed and reported	This is the lowest level of technology readiness. Scientific research begins to be translated into applied R&D. Examples might include paper studies of a technology's basic properties or experimental work that consists mainly of observations of the physical world. Supporting Information includes published research or other references that identify the principles that underlie the technology.

[1] Simulants should match relevant chemical and physical properties.
[2] Testing with as wide a range of actual waste as practicable and consistent with waste availability, safety, ALARA, cost and project risk is highly desirable.

Source: U.S. Department of Energy, "Technology Readiness Assessment Guide". Office of Management. 2011.

2.7 Appendix – Value Sensitivity to Storage Duration

Using the approaches described above the storage duration has been increased in 1-hour increments and for each size of storage we evaluated the potential arbitrage margin for a year and the implied 25 years NPV of that gross margin at a certain interest rate. The basic economic maximization concept is reaching marginal benefit equal to marginal cost. While perfect "maximization" is impossible under real life uncertainties, understanding the behavior of marginal benefit and marginal cost is then critical to design the proper system.

Table 2-27. Energy Arbitrage Gross Margin and Implied Present Value (PV) over a 25 year period – Real Time prices on hourly terms (average 2015 – 2021).

NPV vs storage capacity - Case: 3 Real Time Zeltman - WACC: nominal = 6% / real: 4% - period= 25 years - based on 2015-2021 historical price data

Hours of storage	Energy Arbitrage - Gross margin in $/KW-Month	Cumulative Present Value $/KW	Marginal PV of extra hour of storage ($/KWH)	Average PV per hour of storage ($/KWH)
1	$2.21	$414.30	$414.30	$414.30
2	$3.16	$592.39	$178.09	$296.19
3	$3.65	$684.25	$91.86	$228.08
4	$4.06	$761.11	$76.86	$190.28
5	$4.31	$807.97	$46.87	$161.59
6	$4.53	$849.22	$41.24	$141.54
7	$4.69	$879.21	$29.99	$125.60
8	$4.83	$905.46	$26.25	$113.18
9	$4.94	$926.08	$20.62	$102.90
10	$5.04	$944.82	$18.75	$94.48
11	$5.14	$963.57	$18.75	$87.60
12	$5.22	$978.57	$15.00	$81.55
13	$5.29	$991.69	$13.12	$76.28
14	$5.36	$1,004.81	$13.12	$71.77
15	$5.41	$1,014.19	$9.37	$67.61
16	$5.47	$1,025.43	$11.25	$64.09

Key Point: The marginal value of an additional hour of storage falls rapidly on Real Time Price arbitrage applications, which leads to the conclusion that there is no need to install large levels of storage for each MW of peak output.

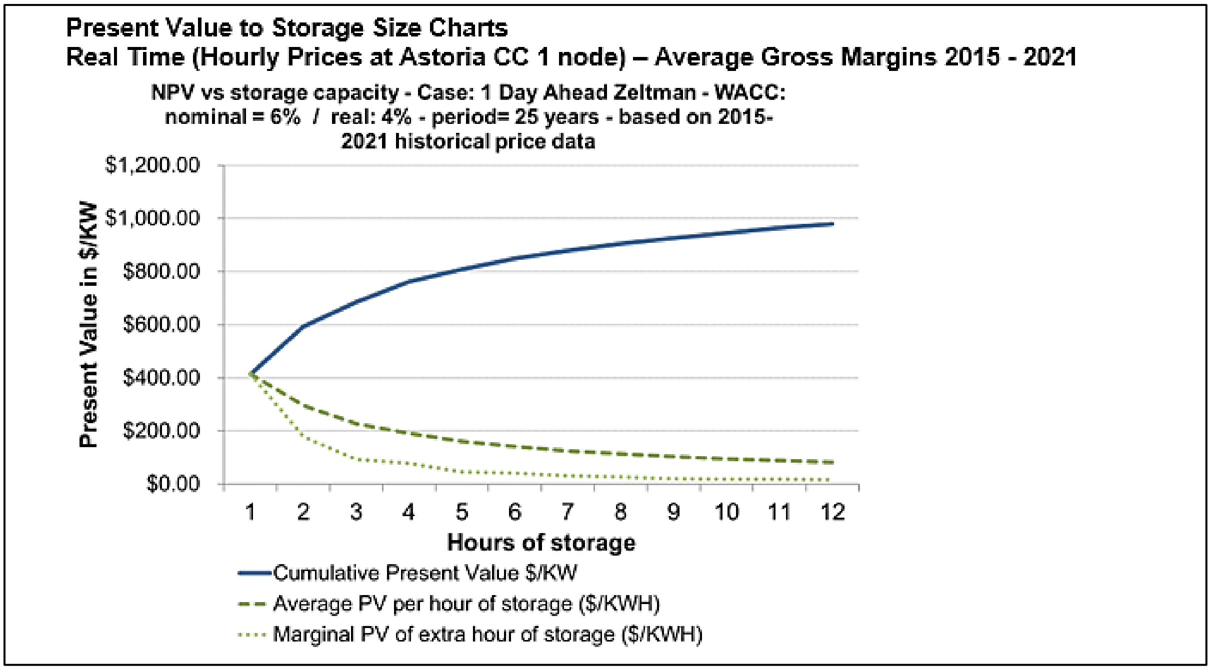


Figure 2-31. Present Value to Storage Size Charts. Real Time (Hourly Prices at Astoria CC 1 node) – Average Gross Margins 2015 - 2021

Table 2-28. Energy Arbitrage Gross Margin and implied present value (PV) over a 25 year period– Day Ahead Prices (Average 2015-2021)

NPV vs storage capacity - Case: 1 Day Ahead Zeltman - WACC: nominal = 6% / real: 4% - period= 25 years - based on 2015-2021 historical price data

Hours of storage	Energy Arbitrage - Gross margin in $/KW-Month	Cumulative Present Value $/KW	Marginal PV of extra hour of storage ($/KWH)	Average PV per hour of storage ($/KWH)
1	$0.68	$127.48	$127.48	$127.48
2	$1.27	$238.08	$110.60	$119.04
3	$1.75	$328.06	$89.98	$109.35
4	$2.11	$395.55	$67.49	$98.89
5	$2.38	$446.17	$50.62	$89.23
6	$2.52	$472.41	$26.25	$78.74
7	$2.70	$506.16	$33.74	$72.31
8	$2.78	$521.15	$15.00	$65.14
9	$2.93	$549.27	$28.12	$61.03
10	$3.01	$564.27	$15.00	$56.43
11	$3.12	$584.89	$20.62	$53.17
12	$3.21	$601.76	$16.87	$50.15
13	$3.30	$618.63	$16.87	$47.59
14	$3.38	$633.63	$15.00	$45.26
15	$3.43	$643.00	$9.37	$42.87
16	$3.48	$652.38	$9.37	$40.77

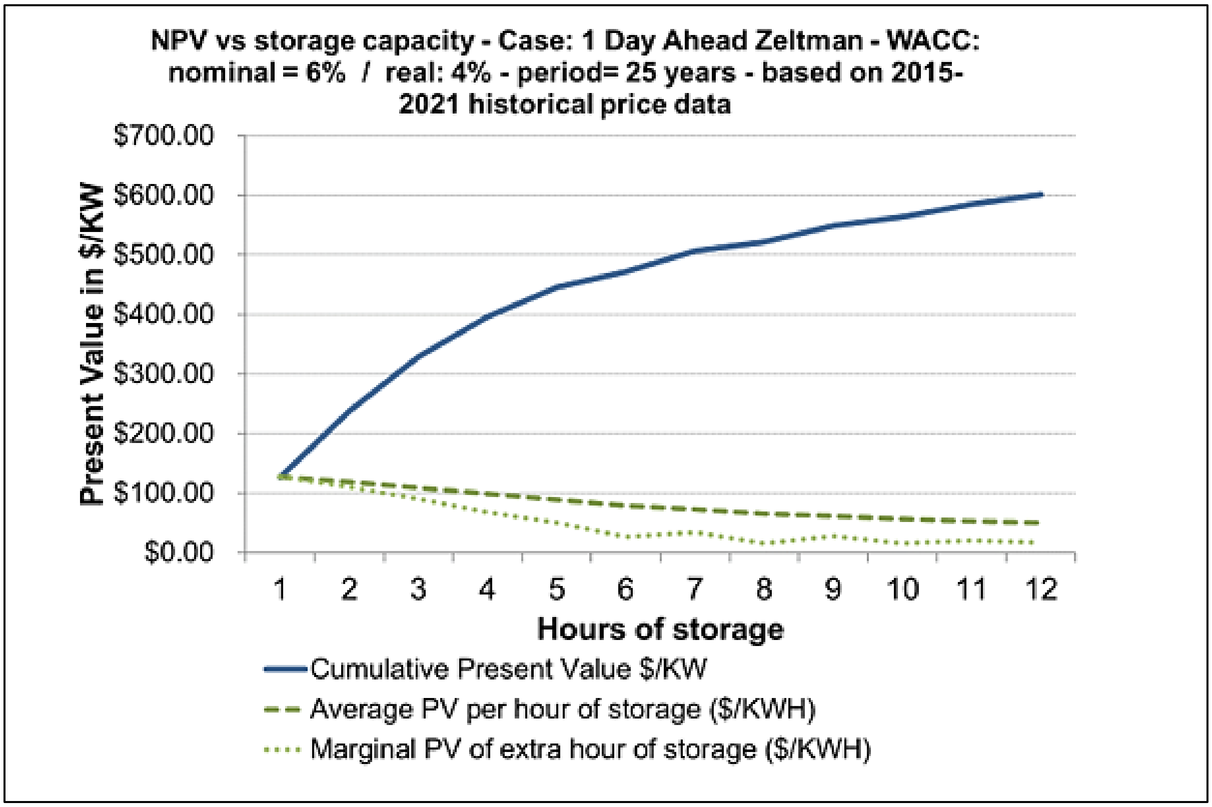


Figure 2-32. Day Ahead Prices (Average Gross Margins 2015 – 2021)

The charts above demonstrate that there is a distinct evolution for each series of prices. Real-time prices showed margins in which the most value was in the first and second hour of storage and with a large drop afterwards. The energy arbitrage value of 4 hours of storage was 72.3% of the value of 24 hours of storage and 45.5% of the unrestricted theoretical limit. Furthermore, the marginal effect of the 2nd hour was roughly double the effect of the 3rd hour. The marginal value drops below 50$ /KW at the fourth hour of real time storage. Both Marginal and Average Curves drop quickly.

Day Ahead prices do not behave the same way, while there is also a decreasing value to storage size curve, the marginal and average value drops are much smoother. The marginal value of the third hour is only 19% lower than the second hour (for this data set).

While average wholesale prices sometimes drop in markets with high renewable penetration, the range of prices (maximum to minimum) increases.

2.8 Appendix – Zeltmann Historical Generation

Table 2-29. Historical Generation at Zeltmann Power Plant

NGCC - ORISPL Code 56196 Operations (Zeltman) -					
Year	MWH Produced (Net Generation EIA 923)	MWH Produced (Gross Generation - from EPA hourly reports)	Capacity Factor	Hours in which at least one unit was operating (From EPA hourly data)	percentage of total hours operating
2014	3,307,582	3,441,115	75.5%	7,894	90.1%
2015	2,891,433	3,012,151	66.0%	7,616	86.9%
2016	2,722,323	2,742,713	62.2%	8,027	91.6%
2017	2,223,713	2,306,577	50.8%	7,606	86.8%
2018	2,127,987	2,213,411	48.6%	6,696	76.4%
2019	2,446,465	2,522,227	55.9%	7,703	87.9%
2020	2,513,912	2,519,277	57.4%	7,772	88.7%
2021 (through June)	1,264,046	1,281,626	57.7%	3,701	84.5%

3.0 TECHNO-ECONOMIC ASSESSMENT

3.1 Introduction

The objective of this task is to perform a techno-economic study to evaluate the cost and performance for a commercial-scale application of the bGen™ thermal energy storage (TES) technology, when integrated with a fossil plant. The study will focus on the NGCC markets segment and will leverage prior testing and demonstration work performed by Brenmiller Energy (Brenmiller). Performance is based on a scaled-up process model that was developed in association with prior testing and demonstration work. Costs were estimated using a bottom-up costing approach in conjunction with an experienced engineering company to improve the validity especially for off-the-shelf balance of plant equipment and systems.

During the conceptual design study, the project team analyzed four different potential scenarios, based upon installation at the NYPA Zeltmann power plant, located in Astoria, New York. The scenarios range from a pure thermal charging of the TES using hot flue gases from the two onsite combustion turbines, up to a full charging of the TES with an electrical source, and a scenario utilizing the hybrid charging capability of the bGen™. The electrical sources utilized may be the locally-produced electricity or the future renewable electricity from the grid.

Each scenario was analyzed in multiple dimensions, starting from the concept description, the potential process flow diagram, its assumed streams of annual revenues, the incremental output power and capacity produced, the estimated investment per each scenario and the resulting net present value (NPV) or return on investment for each scenario.

To have a balanced comparison, a storage capacity of 200 MWh thermal has been selected for all the four scenarios. This size was selected to enable the utilization of the existing installed capital equipment at Zeltmann plant for the incremental power produced by the TES, with no need to increase the capacity of the existing steam turbine. Such a TES size adds an increment of 17.8 MW to the steam turbine output.

Looking at the financial results of each of the four scenarios from the conceptual design study, the complexity of implementation of each of the configurations in the different scenarios, the risk associated in the implementation of each scenario and the flexibility for future different penetration ratios of the renewables on the grid, hybrid charging using steam and electricity (Scenario #4) was selected as the basis for this techno-economic assessment.

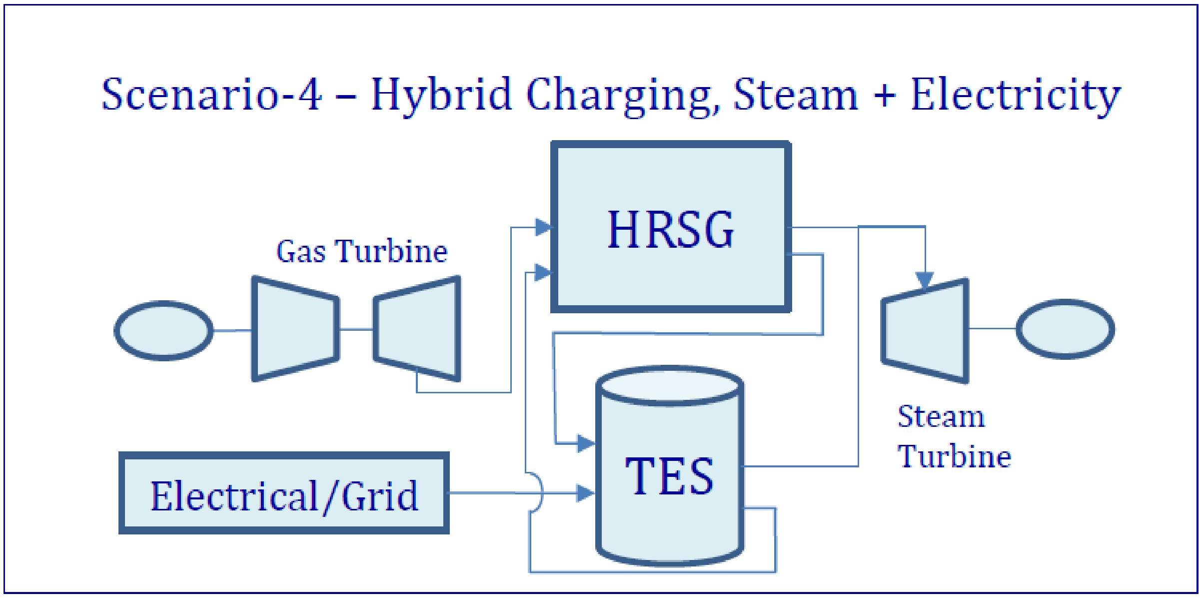


Figure 3-1. Scenario #4 -Hybrid Charging, Steam + Electricity

Under scenario #4, shown in **Error! Reference source not found.**, superheated steam is taken from the heat recovery steam generator (HRSG) output to heat the bGen™ TES at 1,040°F (560°C). Residual steam exits the bGen™ TES during the charging cycle at 623°F (328°C) and is sent back to the HRSG for reuse at the steam generation cycle. To enable the bGen™ TES to produce steam at the required conditions for the steam turbine, out of the internal collected energy, the TES is topped with supplemental charging using the grid electricity. The bGen™ charging cycle would occur primarily during off-peak periods, when power prices are low and/or the facility is operating in turndown mode. Utilizing the embedded capability for electricity conversion to high temperature heat, additional charging takes place during off-peak hours using local produced electricity or electricity from the grid. When charging from grid and when available, the cycle can use renewable electricity. It is assumed that the share of renewable electricity on grid will grow in future years. During periods of premium power prices (day ahead or real-time prices), the discharge cycle will be activated by flowing feedwater through the hot bGen™ media causing the feedwater to flash to high-pressure steam at 1,827 psi, and 1,040°F (126 bar, 560°C) that would be combined with steam flowing from the HRSG and admitted into the steam turbine to produce additional electric power.

The bGen™ ability to charge from both the thermal and the electrical sources creates a device that stores low-value, off-peak energy and re-injects that energy into the facility steam cycle to boost steam turbine generator ("STG") during periods of high electricity demand/prices. Charging with steam comes at the cost of reduced electricity output in the STG.

The proportion of steam extracted for charging the TES is calculated according to the installed TES size, 200MWh thermal in the current project analysis. As this scenario assumes a hybrid charging mode, the analysis includes 75% charging of the TES capacity using steam from the high-temperature steam generator, and 25% charging from the electrical source. The ratio of electricity used for charging is assumed to grow along with the renewable energy penetration on the grid. The analysis is based on 4 hours of charging and 4 hours of discharging. There is no requirement for continuous discharging or charging. Thermal charging or electrical charging time slots can be asynchronous. The additional generation of the steam turbine is considered incremental to the current plant generation due to the flexibility of discharge in a non-continuous mode and the low number of discharging hours – 4 hours.

For optimization of the required capital expenditure (CAPEX) investment in this scenario, the scenario has been designed to enable only thermal charging or discharging at the same time. No parallel charging and discharging of superheated steam. Such a design enables multiple cycles per day, depending on the selected TES size. Electricity can be used for charging the TES at any time, during charging or discharging and especially at off peak time slots.

The incremental annual generation resulting from the bGen™ TES system can reach 35,000 MWh. Using a simple assumption of 1 ton of CO_2 per 5 MWh electricity production, while working with a hybrid mode of 25% renewable Grid electrical charging, there will be an annual reduction of 1000 tons of CO_2. When available and 75% renewable electrical charging is used, annual emissions reduction will total approximately 4000 tons of carbon.

3.1.1 Process Description

The heat balance shown in Figure 3-2 represents the hybrid charging using both HRSG superheated steam and converted electricity from the grid. The conversion of electricity to high temperature heat inside the TES unit is using the embedded conversion capability. The heat balance shows the return path of lower temperature steam as well to the HRSG.

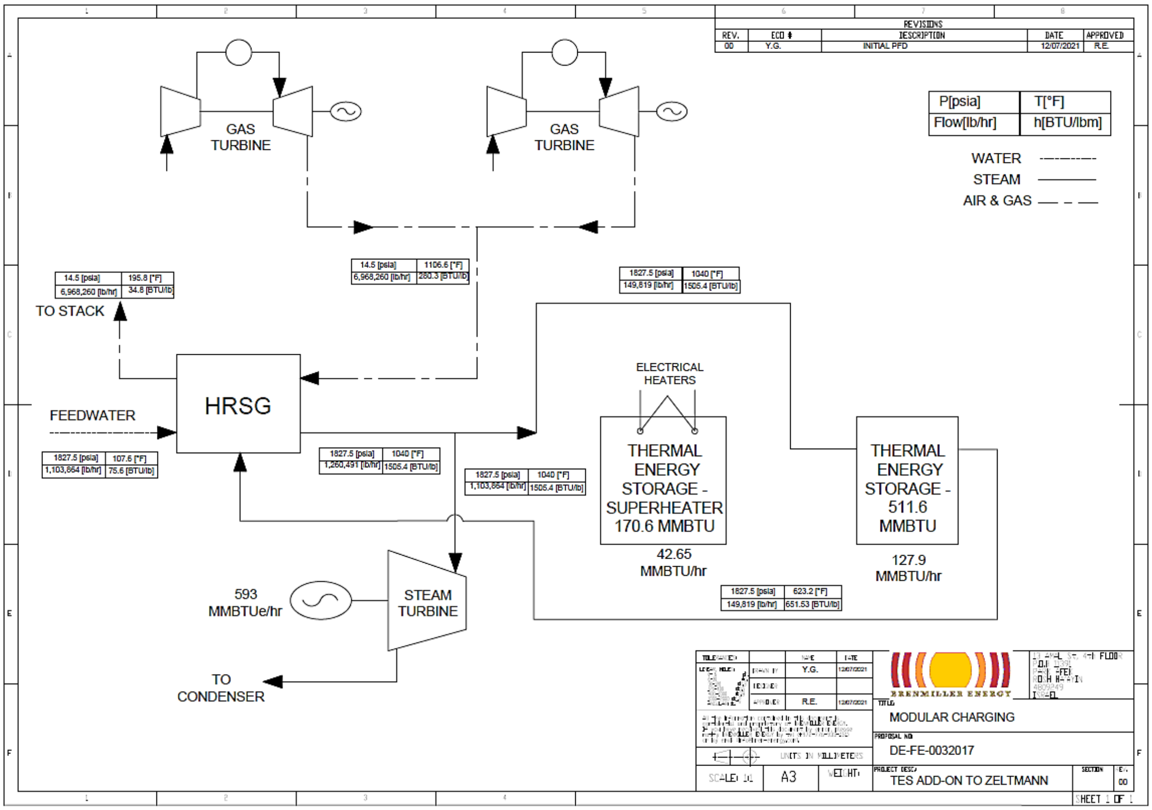


Figure 3-2. Heat Balance Diagram - Scenario #4 Hybrid Steam/Electric Charging

3.2 Design and Cost Basis

3.2.1 Design Basis

This section provides the overall design basis and assumptions that were used to develop the conceptual design for the bGen™ energy storage system.

3.2.1.1 Site Characteristics

The Brenmiller crushed-rock TES technology was analyzed for an installation at NYPA's Eugene W. Zeltmann Power Plant (Zeltmann), a natural gas combined cycle (NGCC) power plant. Figure 3-3 shows the site location, while Figure 3-4 shows the site plan.

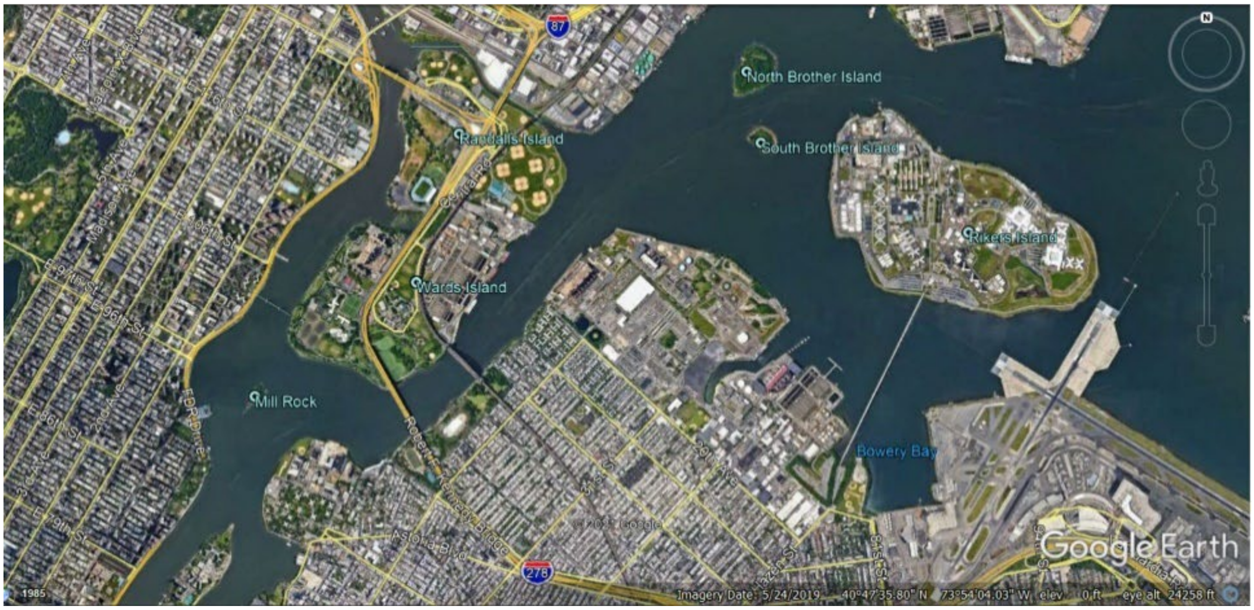


Figure 3-3. Zeltmann Plant – Queens, NY, Arial Photograph

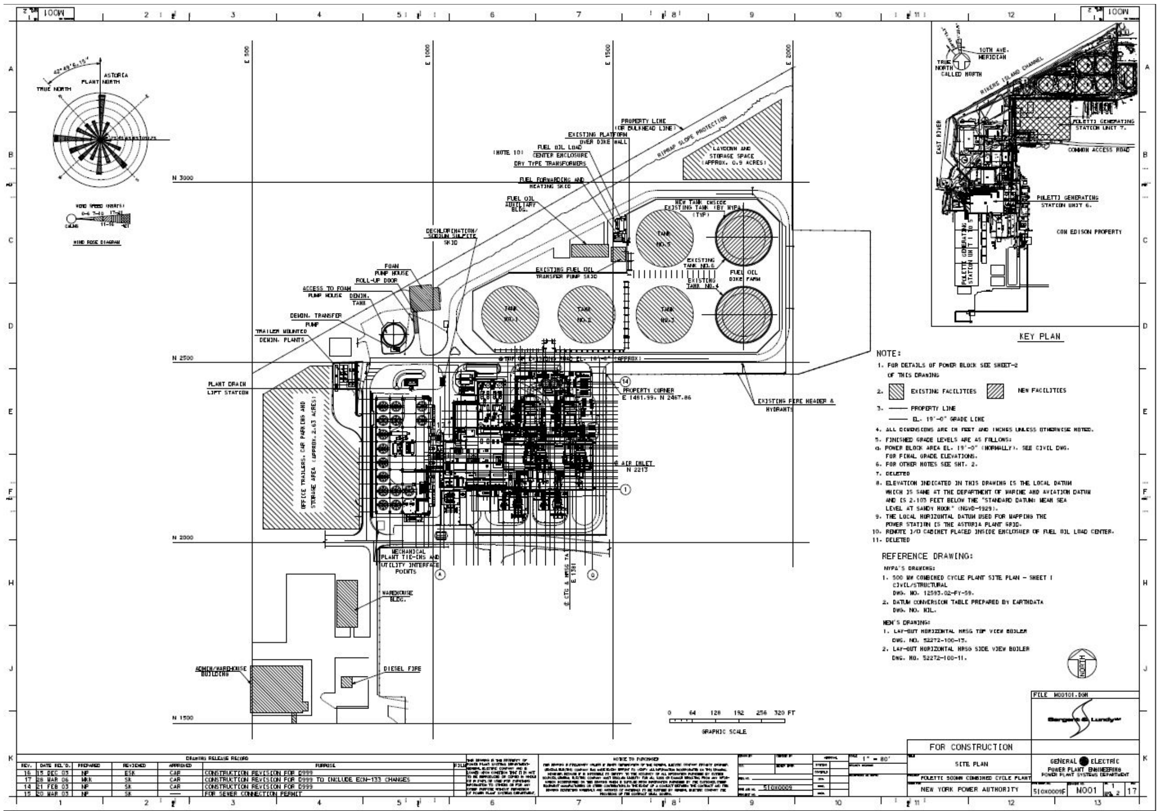


Figure 3-4. Zeltmann Plant – Site Plan

The conceptual design study assumed installation of the TES at one of the prepared locations for a tank, one of the 6 locations shown in the above mechanical arrangement (see Figure 3-4), the closest to the two HRSG's and the steam turbine.

3.2.1.2 Storage Capacity

A storage capacity of 200 MWh thermal was selected to enable the utilization of the existing installed capital equipment at Zeltmann plant for the incremental power produced by the TES, with no need to increase the capacity of the existing steam turbine.

3.2.1.3 Sources of Charging Energy

The storage system is designed to charge and discharge from both thermal and electrical sources. This creates a device that stores low-value, off-peak energy and re-injects that energy into the facility steam cycle to boost steam turbine generator ("STG") during periods of high electricity demand/prices. Charging with steam comes at the cost of reduced electricity output in the STG.

3.2.1.4 Charge and Discharge Durations

The storage system is based on 4 hours of charging and 4 hours of discharging at the rated discharge steam flow and electric output. There is no requirement for continuous discharging or charging. Thermal charging or electrical charging time slots can be asynchronous.

3.2.1.5 Hybrid Charging Assumptions

The initial split of charging assumes 75% charging of the TES capacity using steam from the high-temperature steam generator, and 25% charging from the electrical source. The ratio of electricity used for charging is assumed to grow along with the renewable energy penetration on the grid.

3.2.2 Cost Estimate Basis

This section provides the overall cost estimate basis and assumptions that were used to develop the capital and operating costs for the bGen™ energy storage system.

3.2.2.1 Cost Estimate Methodology

This cost estimate for this project is defined as an AACE Class IV estimate which has typical accuracy ranges of -15% to -30% on the low side and +20 to +50% on the high side, based on AACE International Recommended Practice No. 18R-97.

3.2.2.2 Energy Storage System

The capital cost for the bGen™ storage modules and other major storage system components were provided by Brenmiller. The following are the cost principles which we have used for the Brenmiller scope:

- The cost estimate was based on 692 modules which total the 200 MWh energy storage capacity of the selected scenario. These storage modules are called bCubes.
- The cost estimate for the storage modules is based on the material cost used in the production line in the Dimona Factory, Israel.
- The current production line capacity is 2 bCubes per day. The cost estimate for this study is based on the future throughput which is 5 times higher. The new production line is under development and integration.
- The storage modules are built from local manufacturing parts and externally procured parts. The calculation is based on the cost of standard bare metal that Brenmiller purchases locally with a reduction estimation of 10% due to higher quantities.
- The estimate is based on man hours required for production in the future production line. The cost per man-hour for production in Israel is currently ~$33.

In addition to the storage modules, the following items are required and estimated:

- Insulation - Cost is estimated according to price proposal received in Israel and global suppliers

- Structure - Mostly based on metal cost of received proposals and the required manpower according to the above cost per hour in the production floor

- Site Installation - Based on the assumed required man hours with the cost of 100$ per man hour at a US site

- Electricity and Control - Based on price proposal received for parts and required additional man hour for the integration of the Electricity and control units. United E&C has prepared costs for the balance of plant (BOP) electricity interface

- Engineering localization – Costs are based upon Israeli engineer cost of $80 per hour.

- Project Management - Based on Brenmiller staff at site for required time period, a mix between operation manpower and engineering manpower, according above prices

- Shipping - Based on stabilized containers shipping cost from Israel to the US.

3.2.2.3 Balance of Plant Facilities

Under the current project United E&C (United) has been responsible for costs associated with all balance of plant (BOP) scope. This included engineering (all home office services), procurement, construction management, and startup and commissioning. United developed this estimate utilizing a construction subcontract approach. Process flow diagrams were developed, and a general arrangement drawing was developed for Scenario #4.

BOP Facilities Cost Basis

The BOP cost estimate assumes that most of the work will be performed by a general contractor onsite with specialty subcontracts for the scope items listed below:

- Electrical and Instrumentation

- Electrical testing & control system programming

- Thermal Energy Block Insulation

- Painting & coating

- Foundations/spread footings

- Support steel

The project duration was assumed to be 18 months with construction lasting 12 months. The work schedule is based on a 5-8's productive time workweek (five eight-hour days per week). The construction workforce is based on union shop labor using rates from the NYPA area. Per-diem is not included. That resulted in an average craft manhour rate of $100 per hour.

Bulk material commodities were priced using United E&C's historical database pricing and current market pricing for key items.

Other all-in subcontract costs such as insulation and other items were based on historical data or recent purchase orders.

Indirect costs were based on the following:

- Field Staffing - Included in the estimate based on a ratio of 5:1 craft to staff
- Craft Labor Related Expenses – includes orientation, welder qualifications, drug testing, safety meetings, down time, training, material handling.
- Temporary Facilities & Services – Includes survey, trailer, testing (soil, concrete, pipe), temp toilets, water, site cleanup, data, and phone systems, etc.
- Construction Equipment – Includes equipment rental, fuel, oil, grease, repair, equipment freight, vehicles.
- Small Tools & Consumables – Included at $2.50 per direct MH
- Scaffolding – Included at $4.50 per direct MH
- Commissioning & Decommissioning – Included based on an allowance
- Start up Support (Craft Labor) – included at 1% of the direct manhours

The cost estimate includes freight at 4.5% of all materials and equipment.

General contractor liability insurance is included at 1% of the subcontractor's scope.

Sales taxes are not included.

Engineering and Contingencies

Home office support services during construction is included in the estimate based on a percentage (Project engineer, administration, cost control, business manager, procurement, discipline support).

Engineering services is included in the estimate based on a percentage.

Contingency was not included, but United E&C recommended a 5% contingency for the BOP costs based on the accuracy of the estimate.

Contractor's fee was also not included, but United E&C recommended 10% of the contractor's scope.

Owner's Costs

Owner's costs were not included in the overall estimate

3.3 Performance summary

The overall performance for the hybrid steam/electric charging system (Scenario #4) is based on the process flow diagram shown below in Figure 3-5.

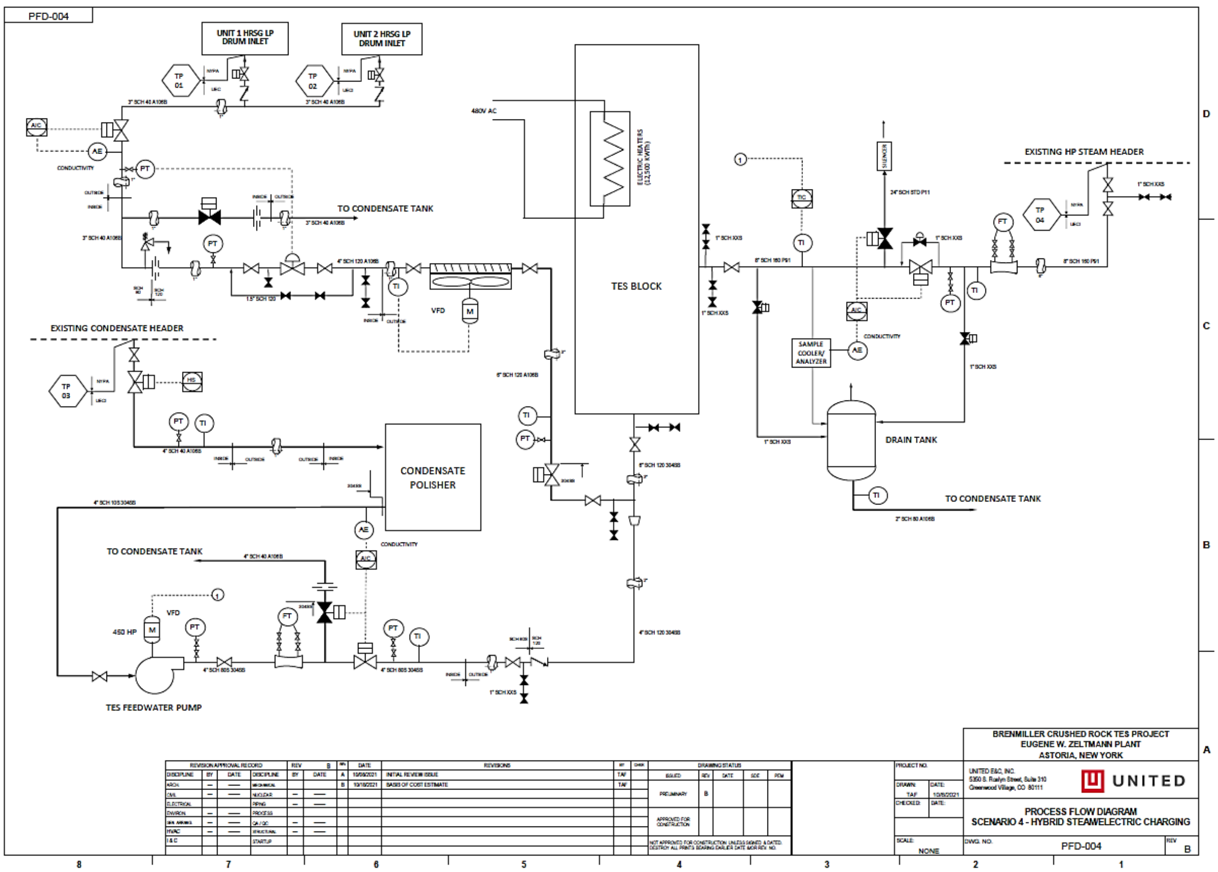


Figure 3-5. Process Flow Diagram - Scenario #4 Hybrid Steam/Electric Charging

3.4 Cost estimates

This section presents an evaluation of the overall capital and Operation and Maintenance (O&M) costs for Scenario #4.

3.4.1 Capital Costs

Error! Reference source not found. details the required investment for this scenario. Future detailed design calculations will give more accurate calculations and address opportunities for possible cost reductions.

Table 3-1. Capital Cost Summary for Scenario #4

Configuration main blocks – Cost	$ M
200MWh bGen™ Storage	$9.0
BOP Connection and Commissioning	$13.3
Total Cost	**$22.3**

The breakdown of the bGen™ storage system cost is given below in Table 3-2 The cost is based on the use of 692 bGen™ modules

Table 3-2. bGen™ Storage System Cost Breakdown

bGen (modules) segmentation	Cost $
Storage modules	6,390,000
Insulation	435,000
Structure	525,000
Site Installation	475,000
Electricity and control	160,800
Engineering localization	150,000
Project management	250,000
Shipping	690,000
Total TES Cost	**9,075,800**

Balance of plant capital costs are shown in Table 3-3, and the balance of plant equipment list is shown in Table 3-4.

Table 3-3. Scenario #4 - Balance of Plant Cost Estimate

CLIENT:	Brenmiller (EPRI)	UNITED						DATE:	18-Oct-21		
PROJECT:	Thermal Energy Storage (TES)							PREPARED BY:	TAF		
LOCATION:								FIELD L FAC:			
JOB NO.:								FIELD L RATE:	$100.00		
REV NO.:											
	TOTAL PROJECT	**SCENARIO 4**									
ACCT	**DESCRIPTION**	**KEY QUANTITIES**		**FIELD WORKHOURS**	**FIELD LABOR**	**MATERIAL**	**OWNER FURNISHED MATERIALS** OWNER HRS	OWNER COST	**TOTAL INSTALLED COST**	**% of DFC**	**% of TIC**
01	DEMOLITION								$ -	0.0%	0.0%
03	EARTHWORK/SITEWORK	222	CY	53	$ 5,256	$ 6,075			$ 11,331	0.1%	0.1%
04	CONCRETE FOUNDATIONS	213	CY	1,076	$ 107,567	$ 107,567			$ 215,134	2.7%	1.6%
05	STRUCTURAL STEEL/ PLATEWORK	21	TN	744	$ 74,375	$ 74,375			$ 148,750	1.9%	1.1%
06	PROCESS EQUIPMENT			500	$ 50,000	$ 850,500			$ 900,500	11.3%	6.8%
06	DUCTWORK	-	TN	-	$ -	$ -			$ -	0.0%	0.0%
11	PIPING	3,290	LF	13,565	$ 1,356,515	$ 1,235,696			$ 2,592,211	32.4%	19.5%
12	ELECTRICAL	68,900	LF	7,056	$ 705,625	$ 2,190,271			$ 2,895,896	36.2%	21.8%
13	INSTRUMENTATION		EA	325	$ 32,500	$ 754,250			$ 786,750	9.8%	5.9%
14	PAINTING / COATING / LINING		ALL	960	$ 96,000	$ 20,000			$ 116,000	1.4%	0.9%
15	INSULATION	2,654	LF	2,007	$ 200,698	$ 86,014			$ 286,712	3.6%	2.2%
16	BUILDINGS (PENETRATION ALLOWANCE)		ALL	250	$ 25,000	$ 25,000			$ 50,000	0.6%	0.4%
	DIRECT FIELD COST			**26,535**	**$ 2,653,536**	**$ 5,349,748**	**-**	**$ -**	**$ 8,003,284**	**100%**	**60.4%**
31B	SUBCONTRACTOR INDIRECTS	20%		5,307	530,707	1,069,950			$ 1,600,657	20.0%	12.1%
	SUBCONTRACTOR CONTINGENCY	10%			$ 318,424	$ 641,970			$ 960,394	12.0%	7.2%
33	SUBCONTRACTOR G&A / OVERHEAD / PROFIT	10%			$ 350,267	$ 706,167			$ 1,056,433	13.2%	8.0%
	FIELD OFFICE EXPENSES								$ -	0.0%	0.0%
	FIELD INDIRECT LABOR								$ -	0.0%	0.0%
41	CONSTRUCTION EQUIPMENT								$ -	0.0%	0.0%
22	HEAVY HAUL/LIFT								$ -	0.0%	0.0%
42	SMALL TOOLS								$ -	0.0%	0.0%
	CASUAL OVERTIME	0%			$ -				$ -	0.0%	0.0%
50	VENDOR STARTUP ASSISTANCE								$ -	0.0%	0.0%
51	CRAFT SUPPORT - COMMISSIONING			300	$ 30,000				$ 30,000	0.4%	0.2%
21	COMMISSIONING SPARES								$ -	0.0%	0.0%
21	FIRST FILLS AND CHEMICALS								$ -	0.0%	0.0%
	INDIRECT FIELD COST			**5,607**	**$ 1,229,398**	**$ 2,418,086**	**-**	**$ -**	**$ 3,647,484**	**45.6%**	**27.5%**
	TOTAL FIELD COST			**32,142**	**$ 3,882,935**	**$ 7,767,833**	**-**	**$ -**	**$ 11,650,768**		**87.9%**
31A	CONST. MGMT STAFF & SERVICES (5% of Direct Cost)	3,078	hrs		$ 400,164				$ 400,164	5.0%	3.0%
61	HOME OFFICE SERVICES (10% of Direct Cost)	6,156	hrs		$ 800,328				$ 800,328	10.0%	6.0%
	START UP & COMMISSIONING SERVICES (2% of Direct Cos	1,231	hrs		$ 160,066				$ 160,066	2.0%	1.2%
	TOTAL FIELD AND HOME OFFICE	**10,466**		**32,142**	**$ 5,243,493**	**$ 7,767,833**	**-**	**$ -**	**$ 13,011,326**		**98.1%**
71	BONDING/BAR							$ 100,000	$ 100,000	1.2%	0.8%
71	WARRANTY							$ 150,000	$ 150,000	1.9%	1.1%
	Total Other Cost				**$ -**	**$ -**	**-**	**$ 250,000**	**$ 250,000**		**1.9%**
94	ESCALATION (NONE INCLUDED - PRICED 2021 DOLLARS)	0.00%			$ -				$ -	0.0%	0.0%
	Total Escalated Cost			**32,142**	**$ 5,243,493**	**$ 7,767,833**	**-**	**$ 250,000**	**$ 13,261,326**		**100.0%**
92	CONTINGENCY				$ -	$ -		$ -	$ -	0.0%	0.0%
	TOTAL INSTALLED COST			**32,142**	**$ 5,243,493**	**$ 7,767,833**	**-**	**$ 250,000**	**$ 13,261,326**		**100.0%**
99	G&A (ON UNITED CM / HO ONLY)				$ -				$ -	0.0%	0.0%
	SUBTOTAL				**$ 5,243,493**	**$ 7,767,833**	**-**	**$ 250,000**	**$ 13,261,326**		**100.0%**
	FEE				$ -	$ -		$ -	$ -	0.0%	0.0%
	SUBTOTAL				**$ 5,243,493**	**$ 7,767,833**	**-**	**$ 250,000**	**$ 13,261,326**		**100.0%**
71	INSURANCE										0.0%
	GRAND TOTAL								**$ 13,261,326**		**100.0%**
	TOTAL CRAFT HOURS			**32,142**			**-**		**32,142**		

Table 3-4. Scenario #4 - Balance of Plant Equipment List

Rev	Equipment Name	Operating Mode (Operating/ Intermittent/ Standby)	Qty	Process (Design/Performance) Data Design Pressure (psig)	Design Temperature (°F)	% Cap	Capacity	Materials of Construction	Nameplate Loads KW	H.P.	Drive Reqt's	Voltage	Operating/ Envelope Dimensions	Insulation	Total Price	Remarks
	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
	TES CONDENSATE & FEEDWATER	Operating	1	---	---	---	---	---	---	---	---	---	---	---	---	
	Condensate Cooler	Operating	1	2500	750	100	60 MMBtu/hr	Carbon Steel	---	---	---	---		---	$ 450,000	Based on CTES cooler quote
	Cooler Fans	Operating	5	---	---	20			---	20	VFD	480 V		---	Incl.	
	TES Condensate Polisher	Operating	1	250	150	100	250 gpm	---	---	---	---	480 V		---	$ 90,000	Full flow IX. Off-site regen. Engineer estimate (some comparison to Belle River polisher quote)
	TES Feedwater Pump	Operating	1	2500	150	100	250 gpm @ 4700 ft TDH	316 SS	---	450	VFD	4160 V		---	$ 130,000	Scaled/adjusted based on multiple past pump quotes
	TES Condensate Storage Tank	Operating	1	ATM	200	100	5000 gallons	316 SS	---	---	---	---	8 ft dia x 15 ft tall	2"	$ 70,000	Heat traced or external pad heaters. Price scaled/adjusted from Crossfield
	TES Condensate Transfer Pump	Intermittent	1	250	200	100	75 gpm @ 600 ft TDH	316 SS	---	20	---	480 V			$ 30,000	Scaled/adjusted based on Jpower Demin Transfer Pump quote
	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
	TES STEAM SYSTEM	---	1	---	---	---	---	---	---	---	---	---	---	---	---	
	TES Steam Sample Cooler/Analyzer	Operating	1	2500	1050	100	0.2 gpm	SS	---	0.25	---	---			$ 5,000	Air cooled. Engineer estimate
	Vent Silencer	Standby	1	15	1050	100	120,000 lb/hr	P11	---	---	---	---			$ 25,000	Based on CTES silencer quote
	TES Drain Tank	Operating	1	15	700	100	500 gallon	Carbon Steel	---	---	---	---	4 ft dia x 8 ft tall		$ 12,000	with vent silencer. Based on multiple past BD tank quotes
	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
	WASTEWATER AND DRAINS	---	1	---	---	---	---	---	---	---	---	---	---	---	---	
	TES Area Sump	Operating	1	ATM	100	100	1000 gallons	Concrete	---	---	---	---	6 ft L x 6 ft W x 4 ft D	---	---	
	TES Sump Pump A	Operating	1	25	100	100	20 gpm @ 25 ft TDH	Iron	---	0.5	---	480 V			$ 3,000	Submersible pumps/rails (from WPS sump pump quotes)
	TES Sump Pump B	Standby	1	25	100	100	20 gpm @ 25 ft TDH	Iron	---	0.5	---	480 V			Incl	
	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
	HVAC	---	1	---	---	---	---	---	---	---	---	---	---	---	---	
	TES Electrical/Control Cab Air Conditioner Unit A	Operating	1			100		---	5 ton	---	---	480 V			$ 10,000	Engineer Estimate
	TES Electrical/Control Cab Air Conditioner Unit B	Standby	1			100		---	5 ton	---	---	480 V			Incl.	
	TES Equipment Enclosure Ventilation Fans	Intermittent	2			100		---	---	5	---	480 V			$ 8,500	Size based on CUF Chem Bldg. Price based on Mill Creek
	TES Equipment Enclosure Unit Heaters	Intermittent	4			25		---	50 kW	---	---	480 V			$ 17,000	Size based on CUF Chem Bldg. Price based on Mill Creek

3.4.2 Operating and Maintenance Costs

It is assumed that the existing operations team at the Zeltmann plant will take control of the TES operation at no additional cost. All the additional installed balance of plant equipment will be maintained by the local power utility staff.

Annual maintenance cost for the TES storage modules is estimated to be approximately 3% of the TES cost (without BOP), or $258,737 per year. This is further broken down as follows:

- Fixed O&M cost = $229,500/year
- Variable O&M cost = $29,237/year

3.5 Economic analysis

3.5.1 Benefits and Potential Income Streams

In the NYISO market, energy storage resources are eligible to receive different levels of capacity credits at discharge duration periods from 2 to 8+ hours. The following potential revenue streams are valid for this scenario's energy calculation:

1. Energy arbitrage based on historical real time prices
2. Additional margin for optimization of the Day Ahead (DA) prices with the real time prices
3. Ancillary services
4. Margins resulting from the penetration of renewables and carbon credits prices
5. Capacity payments for a storage system in the NYISO arena, last guidelines

Values of these revenue streams are presented in Table 3-5 for the year 2023.

Table 3-5. Potential Energy Arbitrage and Capacity Value of bGen™ Storage

Sources of Increased Value of Storage (2023)	Energy Margin $/kW-mo
Deployment based on historical RT prices (4-hr storage)	$4.06
Combination with DA activity + Overall optimization	$1.58
Ancillary services	$0.26
Renewable's penetration, less carbon in off-peak prices	$0.50
Capacity Revenues (Net of ICAP/UCAP and derating factors)	$5.13
Total Energy Margin + Capacity Payment	**11.53**

3.5.2 Overall Cash Flow Analysis

Table 3-6 shows the internal rate of return analysis for Scenario #4. The cash flow analysis shown in Table 3-7 forecasts the overall project revenue and expenses for future years. The year-by-year cash flows assume an annual O&M escalation rate of 2%, while the revenue/energy margin rates from Table 3-5 are assumed to escalate by 2.5%.

Note that the percentage of electric charging increases over time due to the increasing price volatility and real-time margins. This means that there will be more hours to charge at lower, or even negative, prices. Charging electric power cost starts at $10/MWh in 2023 and decreases to -$20/MWh by 2050.

The projected revenue sources for the integrated TES system are shown in Figure 3-6. This shows the predicted economic impact of increased volatility and increasing carbon emissions costs in future years.

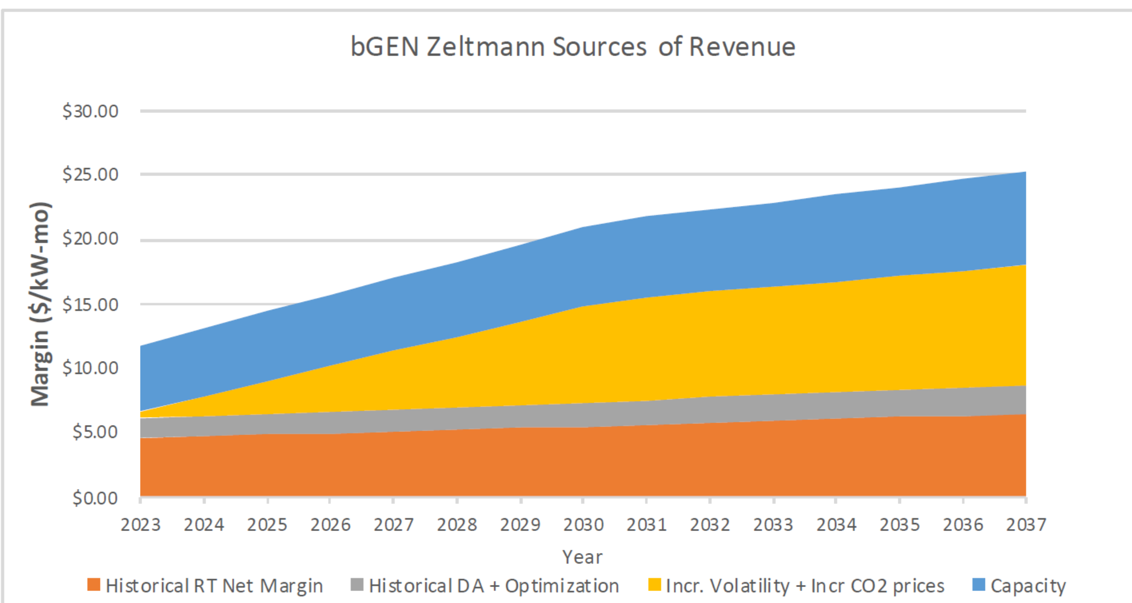


Figure 3-6. bGen™ Installation at Zeltmann – Predicted Revenue Sources

Table 3-6. Project IRR – Scenario #4 – Source of charging energy: Steam and Electricity

		2023	2033
Operating Parameter			
Power Gen capability	kW	17,800	17,800
Electric storage capability	MWh	71.2	71.2
Derated/Adjusted capacity	kW	15,120	15,120
Assumed cycles per day	cycles/day	1.5	1.5
Selling hours	%	1,971	1,971
Annual generation	MWh	35,084	35,084
Hybrid electrical charging		25%	60%
Revenues/Margins			
Real time margin	$/KW/mo	4.06	10.06
Adder for DA and optimization	$/KW/mo	1.58	2.02
Inc. volatility + Renewables + CO2	$/KW/mo	0.5	8.41
Ancillary services	$/KW/mo	0.26	0.33
Capacity price	$/KW/mo	5.13	6.57
Total revenues	**$/KW/mo**	**11.53**	**27.38**
Anuual revenues			
Real time margin	$/yr	867,288	2,147,806
Adder for DA and optimization	$/yr	337,488	432,013
Inc. volatility + Renewables + CO2	$/yr	106,800	1,795,308
Ancillary services	$/yr	55,536	71,091
Capacity price	$/yr	930,787	1,191,486
Total revenues	**$/KW/mo**	**2,297,899**	**5,637,704**
Operating cost			
Variable operating cost	$/yr	29,237	35,640
Fixed operating cost	$/yr	229,500	279,759
Net cash flow	$/yr	**2,039,162**	**5,322,305**
Investment	$	22,261,326	
Project IRR	%	**16.6%**	

Table 3-7. Scenario #4 - Cash Flow Analysis

		2023	2024	2025	2026	2027	2028	2029	2030	2050	2051	2052
Operating Parameter												
Power Gen capability	kW	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800
Electric storage capability	MWh	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2
Derated/Adjusted capacity	kW	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120
Assumed cycles per day	cycles/day	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Selling hours	%	1,971	1,971	1,971	1,971	1,971	1,971	1,971	1,971	1,971	1,971	1,971
Annual generation	MWh	35,084	35,084	35,084	35,084	35,084	35,084	35,084	35,084	35,084	35,084	35,084
Hybrid electrical charging		25%	27%	29%	31%	34%	37%	40%	45%	90%	90%	90%
Revenues/Margins												
Real time margin	$/KW/mo	4.06	4.38	4.74	5.14	5.59	6.10	6.67	7.38	12.43	12.46	12.48
Adder for DA and optimization	$/KW/mo	1.58	1.62	1.66	1.70	1.74	1.79	1.83	1.88	3.08	3.15	3.23
Inc. volatility + Renewables + CO2	$/KW/mo	0.5	1.5	2.5	3.5	4.5	5.5	6.5	7.5	12.79	13.11	13.44
Ancillary services	$/KW/mo	0.26	0.27	0.27	0.28	0.29	0.29	0.30	0.31	0.51	0.52	0.53
Capacity price	$/KW/mo	5.13	5.26	5.39	5.52	5.66	5.80	5.95	6.10	9.99	10.24	10.50
Total revenues	**$/KW/mo**	**11.53**	**13.03**	**14.56**	**16.15**	**17.79**	**19.49**	**21.25**	**23.16**	**38.80**	**39.48**	**40.18**
Anuual revenues												
Real time margin	$/yr	867,288	935,913	1,012,905	1,098,238	1,194,992	1,303,944	1,425,044	1,576,156	2,655,986	2,660,792	2,665,717
Adder for DA and optimization	$/yr	337,488	345,925	354,573	363,438	372,524	381,837	391,383	401,167	657,359	673,793	690,638
Inc. volatility + Renewables + CO2	$/yr	106,800	320,400	534,000	747,600	961,200	1,174,800	1,388,400	1,602,000	2,731,773	2,800,068	2,870,069
Ancillary services	$/yr	55,536	56,924	58,348	59,806	61,301	62,834	64,405	66,015	108,173	110,877	113,649
Capacity price	$/yr	930,787	954,057	977,908	1,002,356	1,027,415	1,053,100	1,079,428	1,106,413	1,812,987	1,858,312	1,904,770
Total revenues	**$/KW/mo**	**2,297,899**	**2,613,220**	**2,937,734**	**3,271,437**	**3,617,432**	**3,976,515**	**4,348,659**	**4,751,752**	**7,966,279**	**8,103,842**	**8,244,844**
Operating cost												
Variable operating cost	$/yr	29,237	29,822	30,418	31,027	31,647	32,280	32,926	33,584	49,904	50,902	51,920
Fixed operating cost	$/yr	229,500	234,090	238,772	243,547	248,418	253,387	258,454	263,623	391,730	399,565	407,556
Net cash flow	$/yr	**2,039,162**	**2,349,308**	**2,668,544**	**2,996,864**	**3,337,367**	**3,690,848**	**4,057,279**	**4,454,544**	**7,524,645**	**7,653,375**	**7,785,367**
Investment	$	22,261,326										
Project IRR	%	**16.6%**										
Project cash flow	-22,261,326	2,039,162	2,349,308	2,668,544	2,996,864	3,337,367	3,690,848	4,057,279	4,454,544	7,524,645	7,653,375	7,785,367

3.5.3 Economic Assessment

Looking ahead to the power generation mix in future years and recognizing that there are limitations on installation of new capital equipment, it is evident that the ideal scenarios must be ready for integration of renewable electricity from the grid. The hybrid steam/electric design described in this study enables a gradual shift from thermal charging sources to electrical (from renewable) charging sources.

The hybrid steam/electric charging scenario evaluated in this study looks quite favorable. The following principles characterize this scenario:

- Charging the TES with superheated steam from HRSG
- Topping with partial electricity charging to enable high temperature steam output to ST
- Utilizing the residual low temperature steam during charging back to the HRSG
- Using the same piping for charging and discharging of steam (for cost reduction)
- Enabling charging with electricity at any given time
- Reaching an internal rate of return (IRR) of more than 16% at the Zeltmann site with 200 MWh of storage

4.0 TECHNOLOGY GAP ASSESSMENT

4.1 Current State of the Brenmiller Thermal Storage Technology

Brenmiller Energy of Rosh HaAyin, Israel, has developed a modular thermal energy storage (TES) system, known as bGen™, using low cost crushed rock as the thermal storage media. The bGen™ system can be configured to be charged via steam, flue gas or electricity, and can discharge hot water or air for thermal utilization and/or steam for power generation (with an additional power cycle), as shown in Figure 4-1. The system is scalable in both power/heat rate and total energy storage quantity by stacking and parallel modules [1].

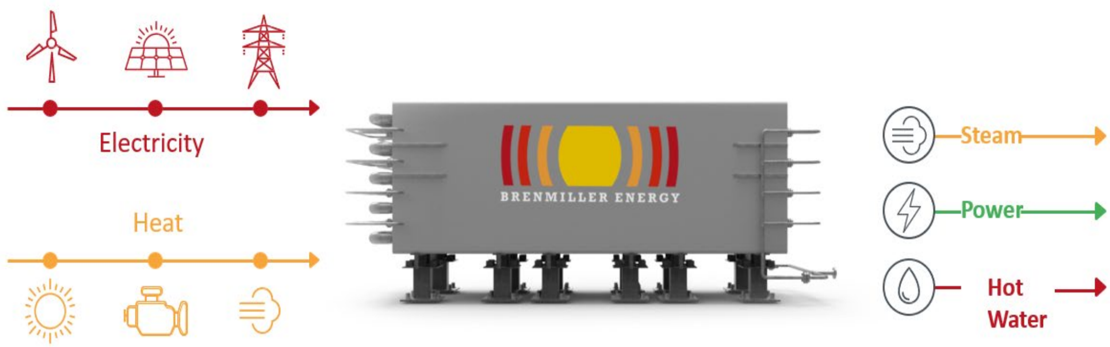


Figure 4-1. bGen™ charging and discharging options

The system has been developed over the last 8 years by Brenmiller Energy resulting in 3 generations of demonstration units at various sites, globally. Brenmiller have undertaken a number of projects during that time, such as the Rotem demonstration site in the south of Israel, Enel pilot in Italy, SUNY Purchase in New York, USA and a Rotomolding hot air supply storage based system in Brazil. These test sites are intended to demonstrate the ability to operate the bGen™ system for a prolonged period of time, thereby validating the unit performance. All these prototype installations are at the stage of final installation and commissioning.

4.2 Future Target for Brenmiller TES Deployment

The Brenmiller modular units, termed bCubes™, can be deployed in various scenarios for different use cases. The scale of deployment and the targeted thermal storage conditions are matched with the duty cycle needed – either industrial or utility cases.

4.2.1 Industrial Scale

Initial deployments of the Brenmiller system have been targeted at small pilot scale demonstrators and industrial scale commercial systems. **Error! Reference source not found.** details various development projects by Brenmiller Energy, and their corresponding status at the time of writing. These projects are built at prototype scales for various market segments, such as the industrial segment for medium to high temperatures, the power utility segment, and the CHP commercial segments. Final installation and commissioning of each of these prototypes is intended to advance the technology readiness for each of the related segments, utilizing the core technology of the bGen™ system.

Table 4-1. Status of other projects undertaken by Brenmiller Energy

Customer	Market	Power	Energy Capacity	Project Stage				
				Planning	FEED	Construction	Commissioning	Operation
Enel Italy	Utility	5 MW	24 MWh-th	Complete	Complete	Nov 2021 – Jun 2022	Jun 2022 – Dec 2022	2023
FORTLEV Brazil	Industrial	400 kW	2 MWh-th	Complete	Complete	Jun 2021- Jan 2022	Feb 2022 – Apr 2022	2022
SUNY USA	Industrial Cogen	400 kW	450 kWh-th	Complete	Complete	Jul 2021 - Dec 2021	Jan 2022 – Apr 2022	2022
IDF Israel	Industrial	150 kW	450 kWh-th	Complete	Complete	Complete	Complete	2021
Zeltmann USA*	Utility	4 MW	16 MWh-th	Apr-Aug 2021	2022	2023	2024	2025

*The Zeltmann project does not currently have construction approval at the time of writing

The industrial design produces temperature and pressure steam conditions of 300-350ºF at 120-150 pig (150-180ºC at 8-10 barg), focusing of thermal delivery of hot water and low-pressure steam. Heating is provided by thermal sources (flue gases, steam) or direct electrical heating. An example design for integration with a microturbine is shown in Figure 4-2.

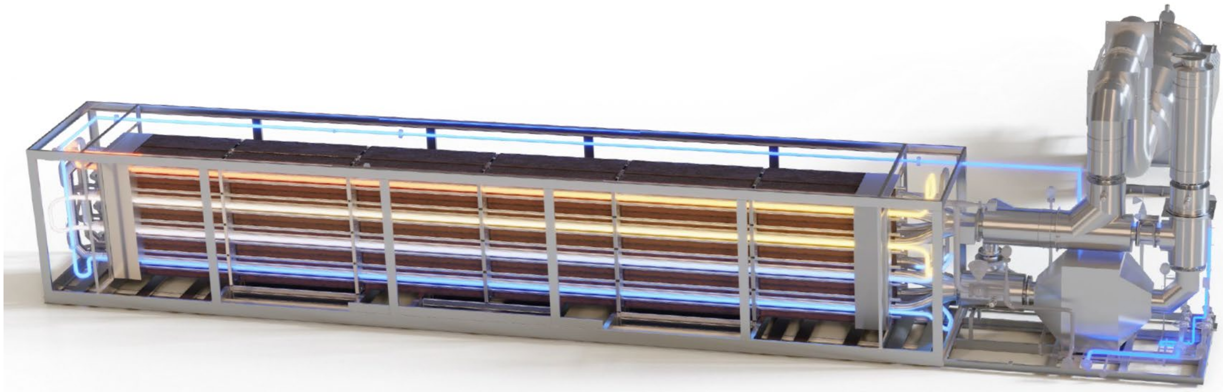


Figure 4-2. Industrial scale application

This design is currently installed and being commissioned at SUNY Purchase in New York, USA

Figure 4-3. SUNY Purchase in New York, USA – 400kW/450kWh

As detailed in **Error! Reference source not found.**, the project installed at the Israeli Defense Force (IDF) has been in operation since early 2021 and has demonstrated at 150kW scale for up to 3 hours of total storage. The operational data collected in this installation (and prior smaller demonstrations) have ensured that Brenmiller have confidence in their process design for industrial application. Several other projects are also scheduled to be operational in 2022.

The bCube™ modules allow for a scalable design. Small deployments can fit into standard shipping containers. Larger deployments will be constructed in stacks and towers depending on site requirements and limitations. The scale-up strategy is shown in Figure 4-4. A current installation at Enel in Italy is already using the stack approach and can be seen at the following images. Coudnations for the system in Italy are already in place including the base structure, next stages are the installation of 64 bCubes.

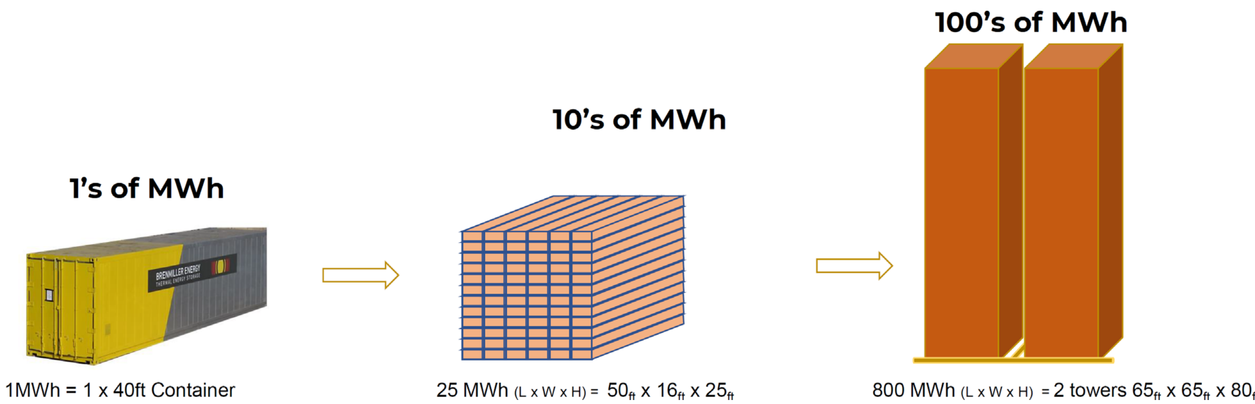


Figure 4-4. bCube™ modular approach to scaling to 100s of MWh

The stacking approach, as implemented at the Enel (Italy) project is fully designed for regulations in Italy related to the design of high rise buildings, for seismic and wind loadings. Finalizing the installation and testing it will cover the required approval of this stacking approach. The design of the stacking approach is shown in Figure 4-5, and the initial construction of a stacking arrangement is shown in Figure 4-6.

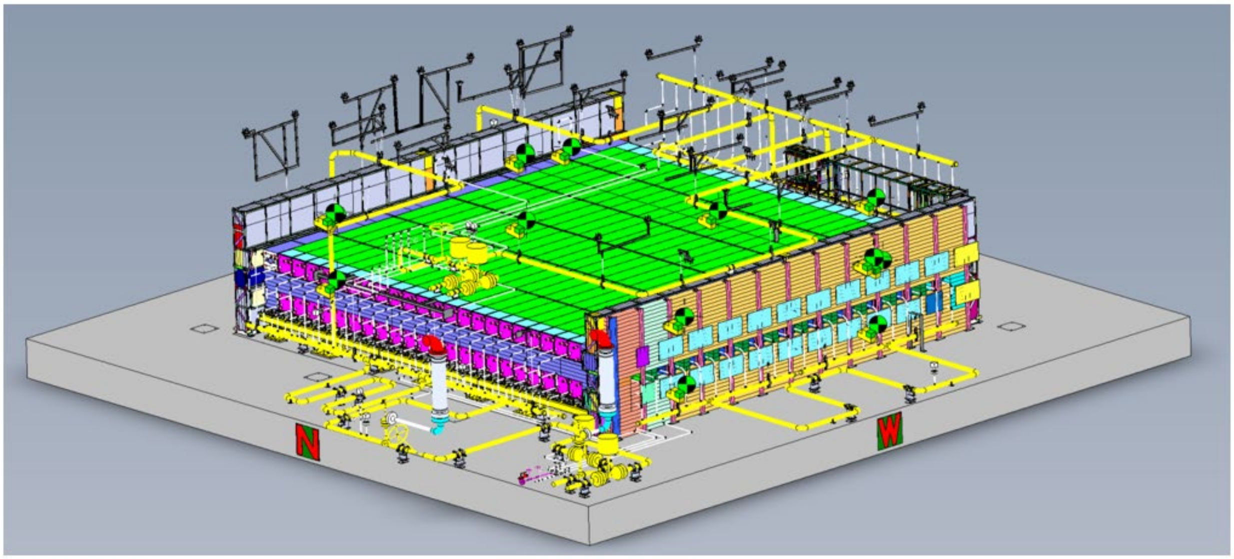


Figure 4-5. Stacking Arrangement Design

Figure 4-6. Construction of Foundation for Stacking Arrangement

4.2.2 Utility Scale

The utility scale variant of the bCube™ design uses materials of construction commensurate with higher service temperatures. As power production is a primary objective of utility scale TES systems, the Brenmiller BCube™ modules have been designed to deliver steam at temperatures up to 550ºC with delivered pressure of 120 barg.

A 24 MWh-th demonstration is being constructed at the time of writing for the Italian utility Enel. The foundations (shown in Figure 4-5) are currently being completed with a base of 12m x12m (40ft x 40 ft), and the bCube™ modules have been manufactured and are currently being shipped to the site. Stacking of these modules is expected to be completed by the end of March 2022. This system has been designed to discharge at temperatures up to 400ºC.

4.3 Technology Gaps

As a result of repeated cyclic testing carried out by Brenmiller during development of the bCube™ system at the testing field at the ROTEM area, the operational performance risks of the design have been addressed, at least up to the operating temperatures used at that site, with the most recent and largest operational system to date at the 150 kWh-th IDF system. Longer term operational risks cannot be fully understood without substantial operating hours and a variety of use cycles. As the Brenmiller TES technology can be configured to operate in several ways, with numerous strategies for charging and discharging – some risks will remain depending on the specific application being served.

4.3.1 Industrial Scale

Technology Gap 1 – Electrical heating elements

Brenmiller has been testing a 2 MWh-th unit with electrical (AC) heating elements since early 2020 to assess the responsiveness of both the charging and discharging with steam production. The system delivered fast response (measurable in minutes) and used heater elements that can operate up to 1300ºC, as tested by Brenmiller, even higher temperatures are possible with different materials of construction. The main technology gap with this element of the system is the sustained operation of these modules.

When failure has been detected in the electrical heating elements, they are designed to be withdrawn and replaced. The system layout will need to reflect the required withdrawal space and spare elements would need to be held at site to minimize the MTTR.

Technology Gap 2 – Long term mechanical failure rates

As the assembly has no moving parts (i.e. passive system within the TES boundary), the only mechanical failure pathways are in the piping (internal and connections), the structure of the bCubes (how they are stacked, how they move relative to each other during thermal cycling operation) and the potential risk from thermal ratcheting inside the structure. While thermal ratcheting is a considerable risk factor for large gravel packed bed TES units, the Brenmiller system has a very small bed width as the material is effectively compartmentalized both horizontally and vertically due to the individual bCube™ modules. An additional supporting factor for the thermal ratcheting is the fact that all bCubes are built with multiple bCell internal units which are each separately effected by the thermal ratcheting.

With extended periods of testing, Brenmiller will be able to determine the mean time between failure (MTBF) rate for each component part of the bCube™ module. As there is no welding connections inside the modules, it is anticipated to have a very low risk of internal failure. Hence the main identified risk is with the outside connections, such as fittings, elbows and in-line welds for distribution headers and manifolds. These risks are minimized by using established installation and welding procedures.

Technology Gap 3 – Water chemistry imbalance

Depending on the installation, the water quality delivered to the bGen™ system may cause some internal corrosion to the tubing. The impact of low corrosion rates can be exacerbated by flow induced corrosion/erosion interaction – this phenomenon should only be possible of the end connections and not the internal tubing due to straightness that will ensure fully developed flow is maintained. However, these mechanisms are complex and the interaction of phase changing conditions and two-phase horizontal flow (if the system is delivering steam as a product) will only be best quantified by extensive testing and strict control of the water quality.

When failures occur and have been detected, the mean time to repair (MTTR) for an operational system will be an important operational characteristic that should also be determined. As Brenmiller do not anticipate any internal failures due to simple arrangement due to there being no internal welding and completely straight tubes, this issue applies to external defects with the installation such as welding issues or the corrosion/erosion interaction described above. Determination of the exact location of the failure, and the procedure for repair needs to be defined for fully stacked, insulated and clad installations. It is likely that a lower MTTR will be achieved by mechanically isolating the damaged module and repairing the module during a scheduled outage.

4.3.2 Utility Scale

Technology Gap 4 – Manufacturing scale

Although Brenmiller currently have the capacity to construct as many as 2 bCubes/day in Israel, this production rate is insufficient for larger scale projects that may require 1000s of modules. This production line is able to produce 300 MWh-th capacity per year on the basis of a single bCube being able to store 0.25MWh-th.

Brenmiller are expanding the existing production line by making it semi-automated to increase from 2 bCubes™/day to up to 10 bCubes™/day – this is scheduled to be completed in 2023. However, this strategy still requires substantial transportation issues to get the modules to the site. While this is acceptable for the current small-scale projects, Brenmiller plans to develop local supply and fabrication when larger scale is needed. The production line configuration can be replicated to other locations in different continents as needed to substantially reduce lead time and transportation costs.

Another risk is that the Brenmiller engineering team will not be able to support the number of individual projects that will be needed as the market for TES installation grows. This includes the need for Brenmiller to deliver on-site support during commissioning and initial operations. Local staff training will be needed however this is currently not being carried out for existing pilot projects.

While the production line is capable of producing the higher pressure pipework, even using P91 materials, the main challenge for these systems is the interface connections to the module. This will be managed by carrying out on site weld verification testing.

Technology Gap 5 – Large scale stacking

The Brenmiller plan to deliver far larger systems without requiring large footprint requirements will require a degree of vertical stacking of the bCube™ modules. As stack heights become larger (see Figure 4-7), the mechanical implications for the lower modules may require additional strengthening of the structure to maintain rigidity.

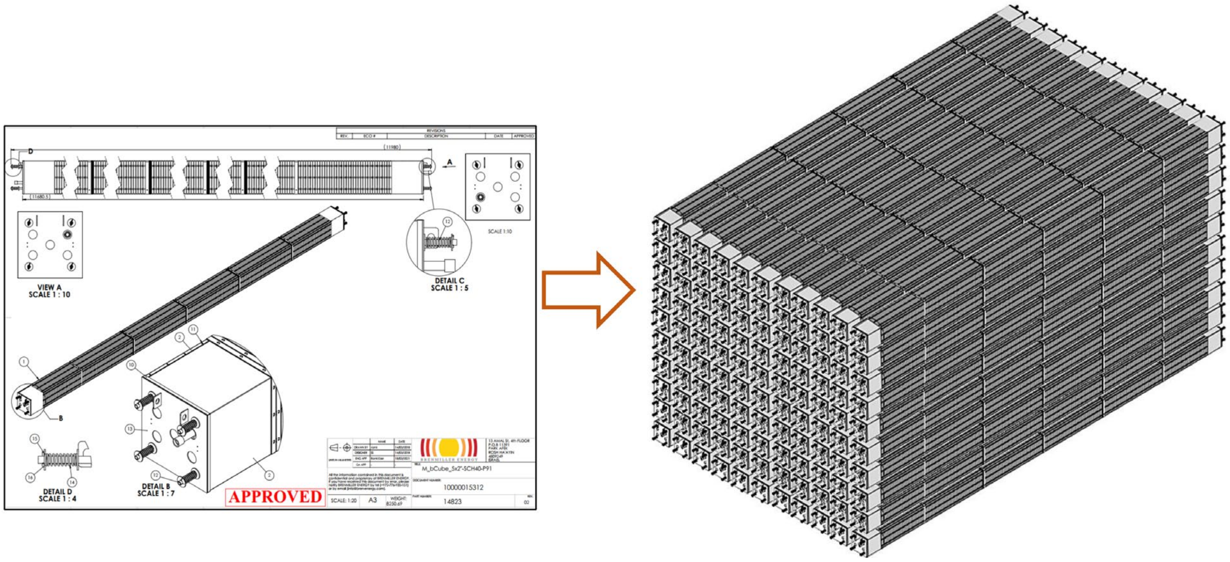


Figure 4-7. Stacking Approach for Utility Scale Installations

Additionally, higher stacks will likely require additional bracing to ensure that seismic stability is assured and wind loading requirements are suitably accounted for.

Technology Gap 6 – Parallel flow stability

As the Brenmiller systems become larger, the vertical and horizontal stack size will need to scale accordingly. This will increase the linear length of the distribution headers and will require additional distribution steps to ensure the pipework has sufficient flexibility for the temperature operating range. As a result of static pressure distribution caused by velocity changes in the manifold, each bCube™ module will experience slightly different flowrates due to the static pressure profile across the manifold, this will alter the heating rates during charging operations (if heated by steam) and the cooling rates during discharge. This behavior will be magnified during the initial discharging steps as some elements will establish stable two-phase flow before others, leading to higher imbalance in both flow and module temperatures.

There may also be issues with vertical static pressure distribution due to the hydraulic head of water and steam between the bottom and the top of a given stack. While adding flow restrictions at the inlet to the network can counteract the vertical distribution during discharge (ensuring feedwater is evenly distributed vertically, as well as horizontally thereby eliminating the header distribution issues stated above), the reverse flow case experienced during charging would not be as well balanced as the restrictions are on the outlet and not the inlet. If the TES is heated electrically or with flue gases, the steam/water flow path will always be operated in one direction (during discharge) and the inlet flow restrictions will be effective. The design uses a charging loop that is different from the discharge loop to help minimize instability issues.

Technology Gap 7 – Dynamic response of bGen™ units

In installations where the Brenmiller TES is being deployed to help balance renewable energy production. The responsiveness of these systems will be of critical importance to the usefulness to the operator in these cases. Brenmiller are claiming hot startup times as low as 5 minutes and warm startup times of 30 minutes for discharge. While this may be possible at the bCube™ level, testing will be needed to verify if larger scale installations can be as responsive given the need for distribution headers and manifolds that will be subject to temperature change rate limitations.

4.3.3 Potential Risks from Operational Externalities

The water chemistry imbalance (Gap #3) can be eliminated if continuous water quality monitoring of the process is installed along with associated controls. However, these systems can be expensive and could be cost prohibitive on smaller industrial scale applications. Thus, the ability of the Brenmiller design to withstand some water chemistry variation over the long term will be a valuable metric for future deployments. This can only be fully assessed with long term ‘real world’ application testing.

The electrical supply for the heating elements (Gap #1) could also cause operational issues if there is variation in the voltage supplied to the elements. To build reliable systems, the electrical interface for the heating elements is controlled by Brenmiller supplied hardware and will be adapted for local power quality conditions.

4.4 Plan to Address Identified Gaps

The gaps identified need to be addressed as the technology progresses to TRL 6-7. The largest installation being installed to date, the Enel project at a CCGT unit in Santa Barbara in Italy, will address the following gaps when substantial operating hours have been carried out:

- Long term mechanical failure rates (partially)
- Water chemistry imbalance
- Manufacturing scale (partially)
- Dynamic response of bGen™ units

Gaps marked ‘partially’ will be fully addressed when more operational time is achieved. As stated previously, the plan for manufacturing scale increases will be progressed this year with semi-automation of the production.

The electrical heating elements (Gap #1) is currently being investigated with small scale testing, however the operational and maintenance risks identified will not be fully addressed until larger scale testing is carried out at pilot scale.

The remaining gaps will be addressed when far larger projects are carried out (in the 100s of MWh-th scale):

- Large scale stacking
- Parallel flow stability

Flow and heat transfer modelling, using hydraulic, finite element and computational fluid dynamic models will need to be carried out to ensure that the parallel flow stability issues are fully incorporated into the design before larger scale deployments can be carried out.

4.5 References

1. https://www.bren-energy.com/

5.0 COMMERCIALIZATION PLAN

5.1 Executive Summary

This Commercialization Plan was developed for the Brenmiller Energy crushed-rock thermal energy storage system, specifically for the case of integration with a natural gas combined cycle power plant, and using a hybrid (steam / electric) charging configuration. The various market drivers were reviewed, including growth of renewable generation, need for increased flexibility, increases in carbon pricing, and increasing market support for grid-scale energy storage. The market potential for energy storage in US and global markets was presented. As part of the US market evaluation, interviews with potential end-users (utilities) were conducted to understand market potential from the customer perspective. Advantages of the technology for the focused markets were presented. Finally, the crushed-rock thermal energy storage system was compared against competing technologies, and a summary of the techno-economic analysis was presented.

5.2 Commercialization Plan

This Commercialization Plan identifies specific market sector targets and demonstrates a compelling pathway to penetration and wide-scale deployment for this thermal energy storage technology. This plan documents the end-user feedback guiding commercialization. The market scenarios and drivers are addressed, including renewables penetration, CO2 constraints/prices, and integration with fossil generation (e.g., coal and natural gas). The domestic and international market applicability of the crushed-rock thermal energy storage technology is reviewed. The market advantages of the concept, especially for integration with fossil power plants, in a setting of increasing variable renewable energy (VGE) penetration. This plan summarizes the estimated additional revenue of the concept, along with estimated additional non-financial benefits to the asset owner.

5.2.1 Market Drivers

5.2.1.1 Renewables Penetration

The growth of renewable capacity is forecast to accelerate in the next five years, accounting for almost 95% of the increase in global power capacity through 2026. Globally, renewable electricity capacity is forecast to increase by over 60% between 2020 and 2026, reaching more than 4,800 GW. This is equivalent to the current global power capacity of fossil fuels and nuclear combined.[10] China, Europe, the United States, and India. account for 80% of renewable capacity expansion worldwide. Electricity generation from renewables is forecast to increase by 8% in 2021 and by more than 6% in 2022. Despite these rapid increases, renewables are expected to be able to serve only around half of the projected growth in global demand in 2021 and 2022.

[10] https://www.iea.org/reports/renewables-2021/executive-summary

In just 10 years, renewable energy's share of US electricity generation has doubled—from 10% in 2010 to 20% in 2020. Over the 2021-26 period, the expansion of renewable capacity in the United States is expected to be 65% greater than in the previous five years. This is the combined result of the economic attractiveness of wind and solar PV, increased ambition at the federal level, the extension of federal tax credits in December 2020, a growing market for corporate power purchase agreements, and growing support for offshore wind. As can be seen from the chart in Figure 5-1 it is expected that the next five years will be driven by a high rate of renewable penetration and a higher retirement rate of conventional power plants (mainly coal). It's forecasted that capacity retirements, increasing renewables and increasing gas competitiveness will push down coal-based generation by almost 5% in 2022. The rate of increase for natural gas power plants will mainly depend on their ability to adjust to the new energy mix and their capability to operate in an economic and efficient way under a new generation regime. Almost 85% of new capacity will be added in Texas, Ohio, Florida, Minnesota, and Pennsylvania. Retirements are set to be concentrated in Texas, where plant closures will account for one third of the US total by 2022 and older.[11]

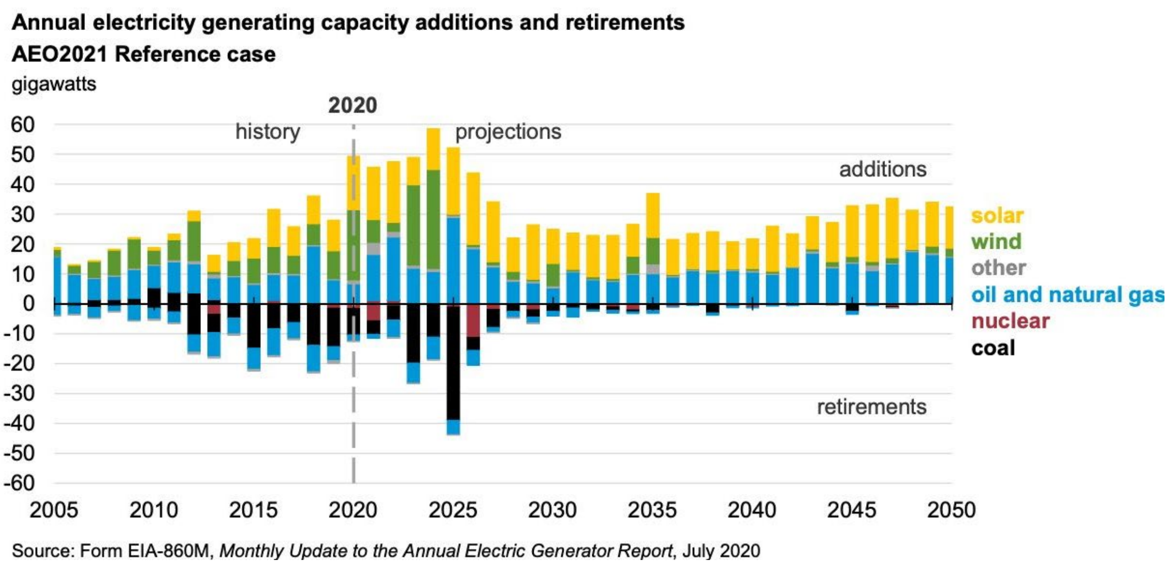


Figure 5-1. Annual Electricity Generating Capacity Additions and Retirements (AEO2021 Reference Case)

5.2.1.2 Required flexibility for market competitivness

Over the last decade, there has been a dramatic change in the power production paradigm. The energy generated by centralized power plants has been progressively integrated with, and even replaced by, power generation from variable renewable sources. This change presents a new challenge for owners of combined cycle plants which are accustomed to baseload operation with regular maintenance intervals. Today, Combined Cycle Gas Turbine (CCGT) power plants are required to operate in a more flexible manner: they follow a double peak demand curve, resulting

[11] IEA, Electricity Market Report, July 2021

in increased number of ramp-ups and daytime stops, as opposed to the traditional method of continuous operation during the week, with major load reductions mainly occurring on weekends.

As a result, these CCGT power plants are experiencing up to 250 start/stops per year, much more than the 50 start/stops per year they were typically designed for as baseload plants. Considering the foregoing, it has become vital for conventional power plants to change their operation mode and technical performance to increase their flexibility, yet at the same time ensure their reliability. The improved flexibility offered to the ancillary service market is the main way to guarantee the competitiveness of thermal power plants. Reduction of the minimum load, increase of the maximum power, reduction of the shutdown and start-up time, optimization of the ramp-up and ramp-down phases, are all capabilities that are increasingly being demanded and whose value continues to increase. Furthermore, energy storage will help to enable power plants to operate during low pricing periods without exporting power to the grid.

Energy storage is well-positioned to play a pivotal role in providing the required flexibility and offer balancing options to these thermal power plants. This is particularly true for Brenmiller Energy's crushed-rock thermal energy storage (TES) solution, which has unique features and can manage the variations in supply and demand at different scales, such as CCGT. Brenmiller Energy's TES allows CCGT to become more flexible and optimize market participation. bGen™ allows CCGT power plants to offer better performance in the ancillary service market with respect to power capacity, spinning reserve, frequency regulation, voltage regulation, reactive power compensation and minimization of imbalance penalties

5.2.1.3 Increasing Carbon Tax and Prices

Carbon Tax prices and Allowances Trading Systems are projected to have an increasing impact upon on the various markets segments, and presents additional opportunity for utilization of energy storage combined utility power plants. There are two main approaches currently used to address carbon; one is a pure taxation of carbon emissions (per ton of CO2 emitted), and the other is the allocation and trading in allowances or green certificates for CO2 pollution. Both approaches are widely and globally used. Europe currently has a robust trading system for the carbon allowances, called the EU ETS. The price of allowances in this system is reaching 100 Euros per ton of carbon, as shown in Figure 5-2.

These mechanisms of the carbon taxation and the trading of carbon allowances, which are becoming mandatory in various countries, are strong motivating factors for utilities and industrial generators to carefully plan their future technology investments to maintain their competitiveness. The combination of the carbon taxes and allowances trading is already changing the market behavior and resulting in reduction of carbon emissions.

In addition, in most countries, the revenues collected from carbon taxes and allowances trading are used to fund green programs and finance installations and modifications to existing sites.

and

Auction Clearing Price

Source: EEX

https://www.eex.com/en/
Liptzig

Figure 5-2. European System of Carbon Allowances trading, Liptzig, Germany

The allowances trading system is based on the Cap and Trade philosophy. The Cap is defined per each country or state and is divided between the utilities and other emitters in that region. Auctions are taking place to trade allowances among entities that have spare allowances, allowing entities to buy allowances to cover carbon emissions.
The cap for each site will be decreased by 4.2% per year, according to the new climate law in Europe. This is intended to drive a decrease in carbon emissions by 42%, below the original cap, over a period of 10 years. Heavy fines are imposed upon generators that do not cover the excess carbon emissions with purchased allowances.

The European Cap and Trade system has been imposed on industrial emitters, power generation utilities, aviation companies, transportation, shipping, and commuter traffic. In 2020 and 2021, the utilization of the carbon tax and allowances trading system in Europe has added 2 cents per KWh (produced from natural gas), and 4 cents per KWh (produced from coal). The resulting carbon emissions reductions (period 2011 – 2019) for the various segments can be seen in Table 5-1.

Table 5-1. Carbon Emissions Statistics, Europe 2011 – 2019 (Millions of tons CO2)

Source: European Environment Agency

Year	2011	2012	2013	2014	2015	2016	2017	2018	2019
Verified total emissions	1 904	1 867	1 908	1 814	1 803	1 750	1 755	1 682	1 530
Change from year x-1		-2.0%	2.2%	-4.9%	-0.6%	-2.9%	0.2%	-4.1%	-9.1%
Verified emissions from electricity and heat production	1 206	1 201	1 138	1 049	1 043	1 001	996	930	792
Change from year x-1		-0.5%	-5.2%	-7.8%	-0.5%	-4.1%	-0.5%	-6.6%	-14.9%
Verified emissions from industrial installations	698	666	770	765	760	750	759	753	738
Change from year x-1		-4.6%	15.6%	-0.7%	-0.7%	-1.3%	1.3%	-0.8%	-1.9%

This table illustrates the limited impact of the tax and trading tools upon the reduction of carbon emissions in the industrial segment. This has prompted Europe to develop special programs that focus on the industrial segment, recognizing that 40% of the emissions come from the industrial segment. To maintain competitiveness and block potential transfer of production and manufacturing to regions where the carbon tax and trading tools are not imposed yet, Europe has defined a special customs process, which is scheduled to be activated beginning in 2024 and is intended to limit the potential arbitrage.

It is anticipated that carbon pricing schemes would have an increasing impact on electricity pricing as renewable generation increases, especially during low-load, off-peak periods. A review of renewables-heavy markets and markets with stronger carbon prices shows that both renewables and carbon have an increasing effect on energy price volatility and high-low spreads. The California Independent System Operator (CAISO) market exhibits both high renewable penetration (primarily solar power, with some wind, hydro and geothermal) and substantial carbon prices. The impacts upon volatility due to these factors are twofold: not only do the price probability distributions get "wider", but they also become more fat-tailed and more asymmetric. The standard deviation of day-ahead prices in California has been increasing significantly in the last few months and is currently reaching values in the $30-40/MWh--almost triple the values of New York state, which are in the $10-15/MWh range.

To evaluate the potential impact of substantially higher carbon prices in the energy price volatility, Southwest Power Pool (SPP) conducted a market simulation based on SPP's current power plant mix. The results of the simulation are summarized on Table 5-2 below. The variability can be measured by statistical techniques including comparing standard deviations among other measures like Mean Absolute Deviation. The effect in the increased standard deviation[12] translates linearly to the estimated maximum margins of the storage system[13].

Table 5-2. Carbon Price Simulation Results

Change in Volatility due to Carbon Price levels: Simulated results for a market with high renewable penetration (SPP)

	Simulated Carbon Price		
	0	$30/ton	$60/ton
Resulting Standard Deviation :Day Ahead Price (Hourly Prices)	$17.70	$34.62	$52.45
Increase over case with no carbon price		95.6%	196.3%

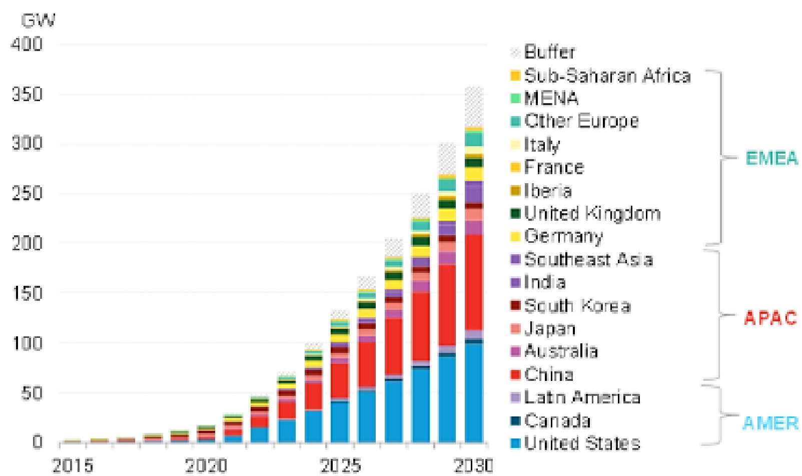
An increase of carbon prices to 60$/ton implies a 196% increase in Standard Deviation. In this case, the probability distribution becomes 3x wider. This would translate into a 3x increase in the implied maximum margin of a storage system in that market. It should be noted that while the New York market already has a carbon offset requirement via the Regional Greenhouse Gas Initiative (RGGI), the average RGGI price in the studied period (9/2015 through 8/2021) has been $5.17/ton, which translates into a relatively muted effect so far. The California greenhouse gas ("GHG") prices are currently in the $25/ton range and GHG prices in Europe are in the 80$/ton range, which can be seen as indicators of future prices in the New York market.

To make our economic/financial analysis consistent with the stated ambitious environmental goals of New York, we focused on scenarios in which carbon prices reach values in the order of 50$/ton. The standard deviations cannot be compared across markets without the full context of the distribution shape, but the magnitudes and percentage changes of that deviation provide a stronger directional indicator. For a change between the current US carbon price range of $5 - $10/ton to the future $50/ton we estimated a linear change of 140% of the expected margin (this affects both Day Ahead and Real Time margins).

[12] There are some potential non-linear effects in the actual results versus the simulated results.
[13] This is a valid assumption when comparing the same system over time and/or its changes.

5.2.1.4 Increasing Market Support for Energy Storage

Despite the challenges brought by Covid-19 and the global pandemic, global energy storage deployments, including all types, nearly tripled year-on-year, reaching 12 GW / 28 GWh in 2020, and are expected to approach 1 TWh by 2030. The total energy storage market is projected to double in size in 2021 to reach 56 GWh, with that number expected to increase 17-fold by 2030.[14] This increase in energy storage deployments is likely to be aided by new policies, such as the proposed 30% investment tax credit for standalone storage proposed in the latest US reconciliation budget proposal. Front-of-the-meter (FTM) storage will drive global storage deployments, with decarbonized efforts around the world pushing the FTM segment past 706 GWh by 2030.



Source: BloombergNEF. Note: MENA = Middle East & North Africa. Buffer represents markets and use-cases that we are unable to forecast due to lack of visibility.

Figure 5-3. Global Cumulative Energy Storage Installations (2015-2030)

Figure 5-3 shows the projected trend of global energy storage installations. The United States and China are the two largest markets and are projected to represent over half of the global storage capacity by 2030. Energy storage installations around the world are projected to reach a cumulative 358 GW /1,028 GWh by the end of 2030, more than twenty times larger than the 17 GW / 34 GWh online at the end of 2020.[15] The US commands a global leadership position in energy storage with a forecast of 40% cumulative share in 2030, while the US FTM market is expected to surpass 300 GWh in 2030, with annual installations hitting 53 GWh that year. (Wood Mackenzie, 2021)

[14] Wood Mackenzie, "Global Energy Storage Outlook: H2 2021", 2021
[15] BloombergNEF, "2021 Global Energy Storage Outlook", 2021

As grid-connected renewable generation increases, the duration of energy storage needed to ensure reliability also increases. As electricity generation transitions away from fossil fuels to renewable sources, more long duration energy storage will be needed. While battery energy storage solutions (primarily based on Lithium-Ion technology) dominate the currently commercialized deployments, many non-battery energy storage technologies are under development, such as compressed air and thermal energy storage. Many of these can provide longer dispatch duration compared to batteries, supporting energy supply during prolonged periods of low renewable energy generation in future net-zero power systems.

As can be seen in Figure 5-4, the key application in this segment, is related to energy shifting.[16] Deployment of energy shifting storage solutions is projected to increase from around 2,500MWh in 2020 to around 12,000MWh in 2022 - a 400% increase in just 2 years.[17]

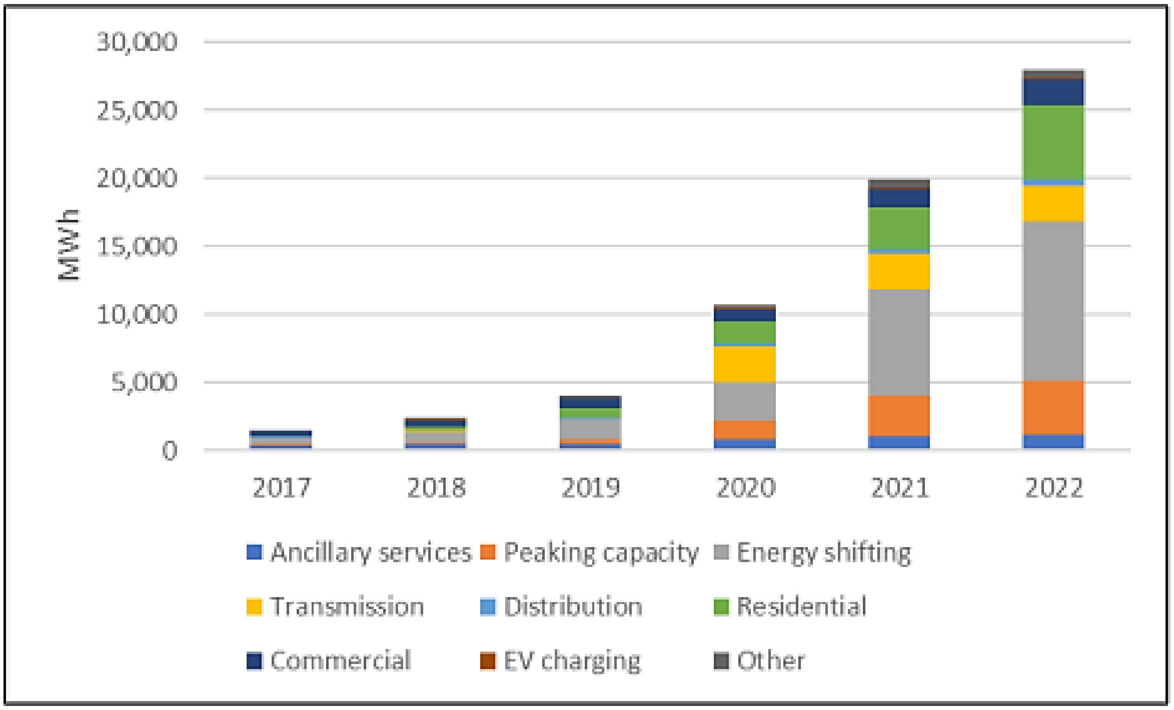


Figure 5-4. Projected Cumulative US Grid-Related Deployment by Application (2015-2022)

[16] Bloomberg New Energy Finance, "2019 Long-Term Energy Storage Outlook", BloombergNEF, New York, 2019.
[17] BNEF's forecast suggests that the majority, or 55%, of energy storage build by 2030 will be to provide energy shifting (for instance, storing solar or wind to release later).

5.2.2 United States Market

As part of the work scope under this award, the project team reached out to potential U.S. customers (end-users) of the crushed-rock TES concept. The goal was to solicit feedback from the power industry via interviews with power generation utilities that are considering adopting TES as part of their future plans. The following summarizes some of the key take-aways from the discussions:

- In support of their decarbonization initiatives, utilities are generally transitioning from fossil fuel generation to variable renewable energy (VRE) generation and are seeking energy storage solutions that can be installed by 2030 (for use with the fossil generating asset), and can transition to support the VRE generation, after retirement of the fossil asset.
- The main requirements that are frequently identified for adoption of energy storage include:
    - Low capital cost
    - Technical readiness by no later than 2030
    - No potential for environmental concerns
    - Small footprint
- There is a perception that crushed-rock TES is similar to concrete TES, with similar benefits and challenges.
- Presently, lithium-ion batteries are seen as the benchmark competition for energy storage.
- Environmental safety is important to the power industry. Certain energy storage technologies (e.g., lithium-ion batteries) have potential environmental concerns. The preferred energy storage technologies will be benign and raise no new environmental issues.
- Many existing power plant installations have limited space, and the footprint of the energy storage is an important consideration. Smaller footprint (higher energy density) will likely be a key factor for adoption by the power industry.
- While high round trip efficiency (RTE) of energy storage is often cited a desired attribute, in many practical cases, especially in market scenarios that involve periods of low (or negative) energy prices, a relatively low RTE, combined with a low capital cost, can result in an attractive energy storage solution.

5.2.3 Global Markets

As a result of disruptions in the electricity generation sector (primarily driven by increasing coal and natural gas prices), and the more extreme weather we are witnessing globally due to climate change, electricity prices in 2021 have become more volatile. In some cases, there are extreme prices (over $1,000/MWh during peak hours) vs. negative prices during off-peak hours. Figure 5-5 shows quarterly average wholesale prices for selected regions for the past six years. This illustrates some of the recent dramatic increases in wholesale electricity prices globally.[18]

[18] IEA, "Electricity Market Report", 2022

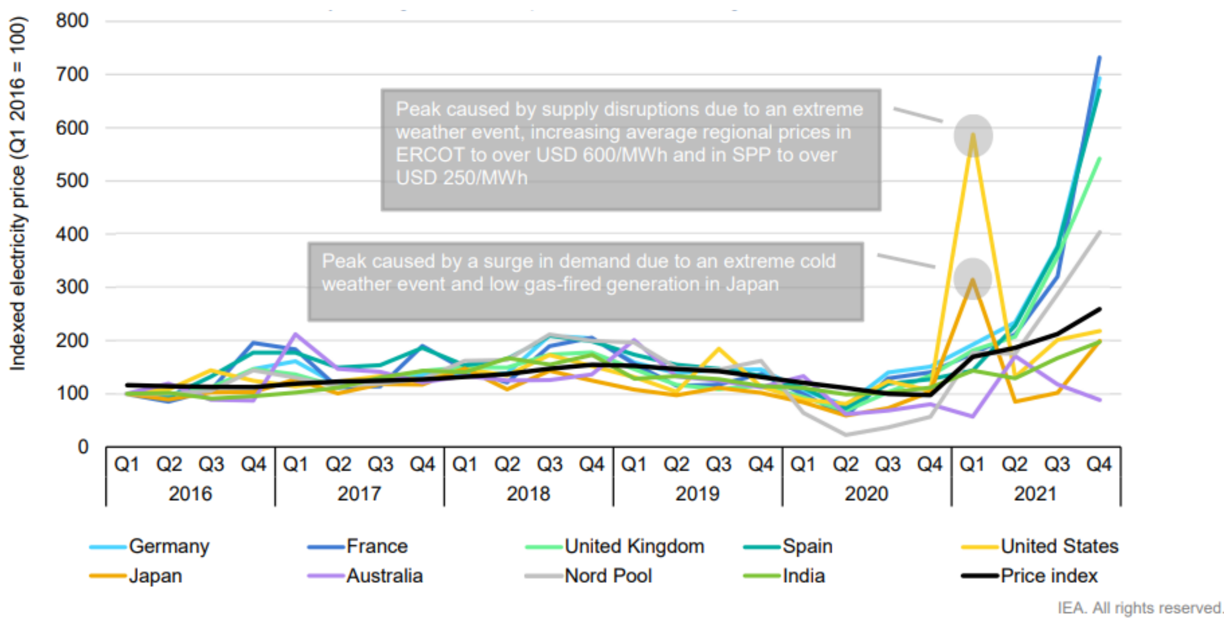


Figure 5-5. Quarterly average wholesale prices for selected regions (2016-2021).
Source: IEA, "Electricity Market Report January 2022", 2022

The need to shift energy from off-peak to peak hours is increasing as more VRE generation (especially wind energy) penetrates the grid. From an economic perspective, energy arbitrage spreads are increasing, along with higher volatility for electricity tariffs. This, combined with frequency regulation, capacity payments and other revenue streams, makes grid-scale energy storage facilities more economically viable.

In different countries the value of energy storage varies. While bill management (avoiding peak charges) delivers the highest value in Canada, in Germany the values derive from energy arbitrage and frequency regulation. Figure 5-6 shows selected results from an international case study on value of energy storage.[19]

[19] Lazard, "LAZARD'S LEVELIZED COST OF STORAGE ANALYSIS—VERSION 7.0", 2021

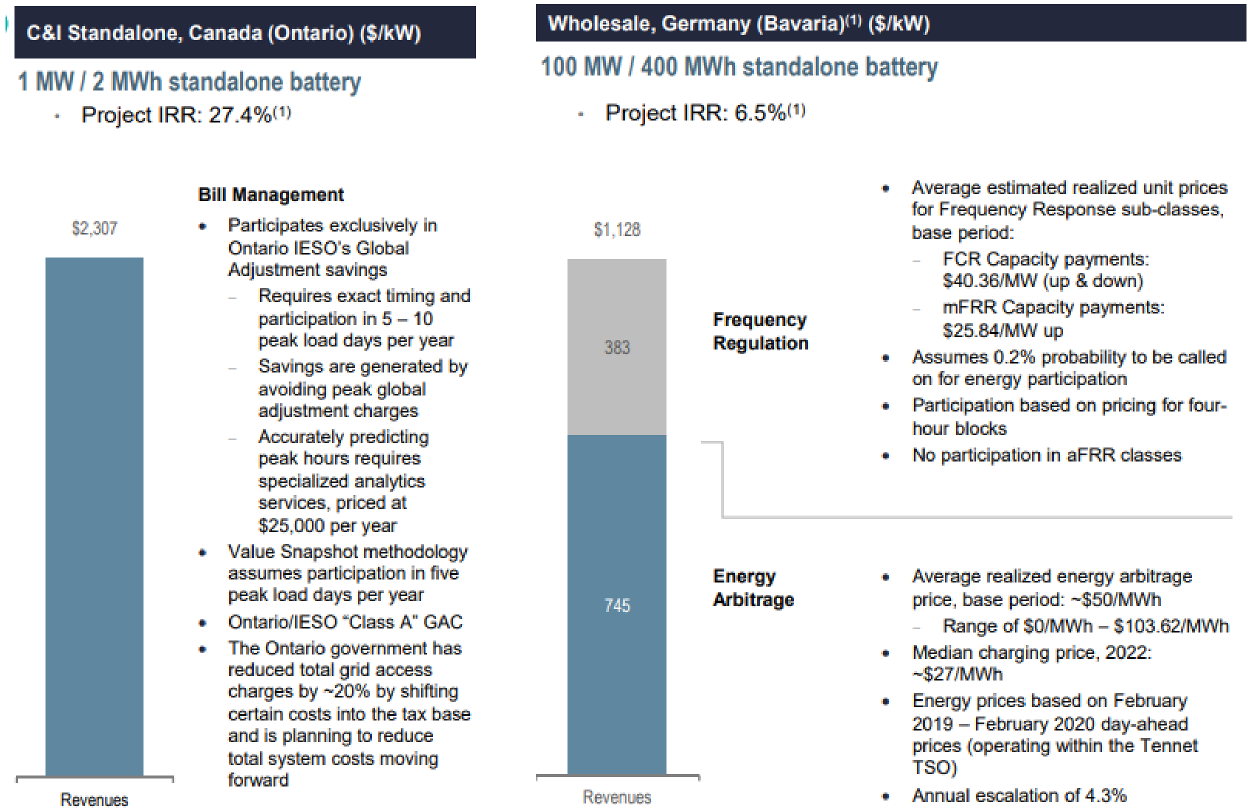


Figure 5-6. Value Snapshot of International Case Studies (Lazard, 2021)

As shown in Figure 5-7, EIA projects that most new power generation plants will be based on renewable energy sources. Global renewable energy share is expected to increase from 29% in 2020 to 61% in 2030 and to 84% in 2040, per IEA's net-zero scenario[20].

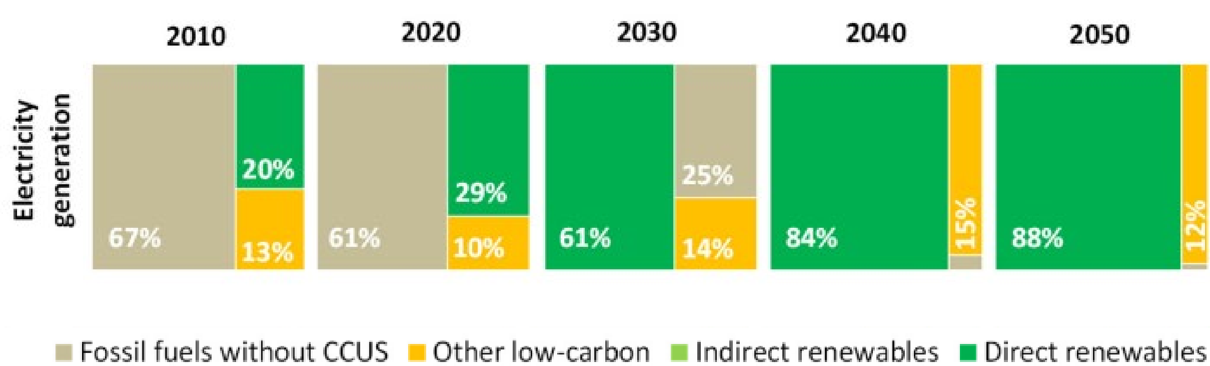
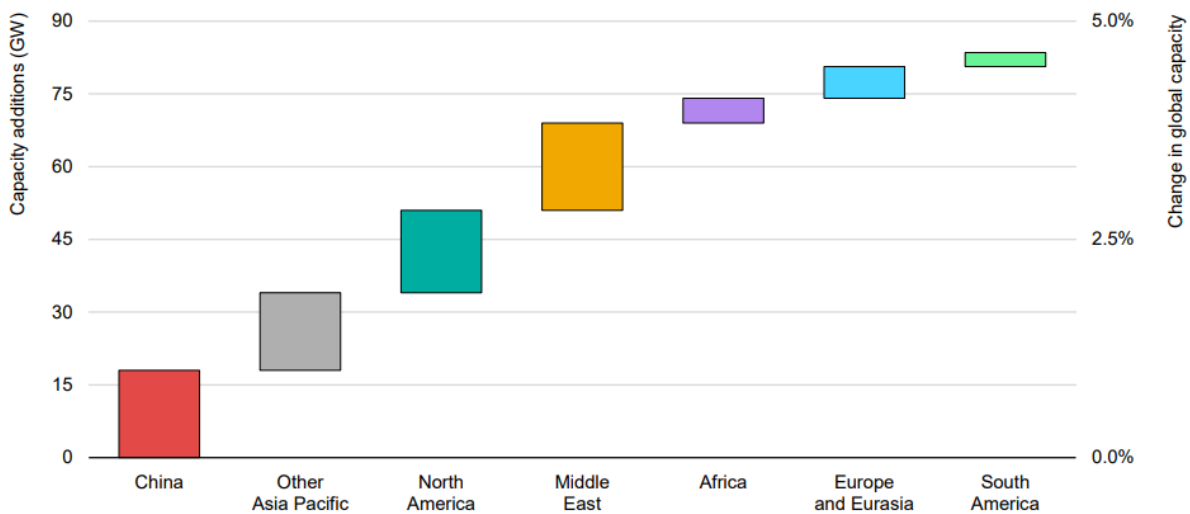


Figure 5-7. IEA's Projection of Electricity Generation Types

[20] IEA- Net Zero by 2050 report, May 2021

This dramatic increase in VRE generation on global electricity grids would require adjustments to the operation profiles of thermal power plants, as well as massive implementations of grid-scale storage facilities, which will be based on a variety of different technologies.

As of 2021, gas-fired power plants capacity is 1,850 GW and accounts for 25% of global electricity generation, which is expected to grow at a compound annual growth rate (CAGR) of 2.5% during the next decade. Figure 5-8 illustrates IEA's projections of short-term additions of gas-fired power generation capacity for various global regions. As coal-based power plants are retired, gas-fired power plants will likely supply most of the baseload needs, and some new combined-cycle power plants will be commissioned in the short and medium term.



IEA. All rights reserved.

Sources: IEA analysis based on EIA (2021), Electricity Data; IEA (2021), *World Energy Investment 2021*; S&P (2021), Energy Power Plant Project List; various companies and news reports.

Figure 5-8. Gas-fired power generation capacity additions by region, 2020-2022.
Source: IEA, 2021

5.2.4 Technology Advantages

Thermal energy storage (TES) represents an ideal technology to support the growing penetration of variable renewable energy (VRE) on the grid. The crushed-rock storage technology, which is being developed by Brenmiller, is a modular TES system termed bGen™, which can accommodate both thermal and electrical inputs and output steam, hot water, or hot air (as shown in Figure 5-9). For a fossil-plant integrated application, the estimated efficiency of the TES system is 80% thermal to thermal, with energy losses of less than 3% per day.

TES is a natural fit for thermal power plants as they both use thermal energy, helping to minimize conversion losses. Crushed-rock TES technology offers unique qualities to meet the needs and challenges of supporting flexibility and grid stability. In addition to offering relatively low cost per MWh and robustness, the technology can be deployed in modules to adapt to various plant sizes.

The bGen^{TM} TES integration with a fossil plant increases the functionality of the plant in a market with growing penetration of VRE. Energy storage will play a pivotal role in providing the required flexibility and offering balancing options to the energy system. This holds true especially for TES concepts, which have unique features and can be used to manage the variations in supply and demand at various scales for a multitude of generation options, including natural gas combined cycle (NGCC), coal-fired power plants and simple cycle gas turbine generators.

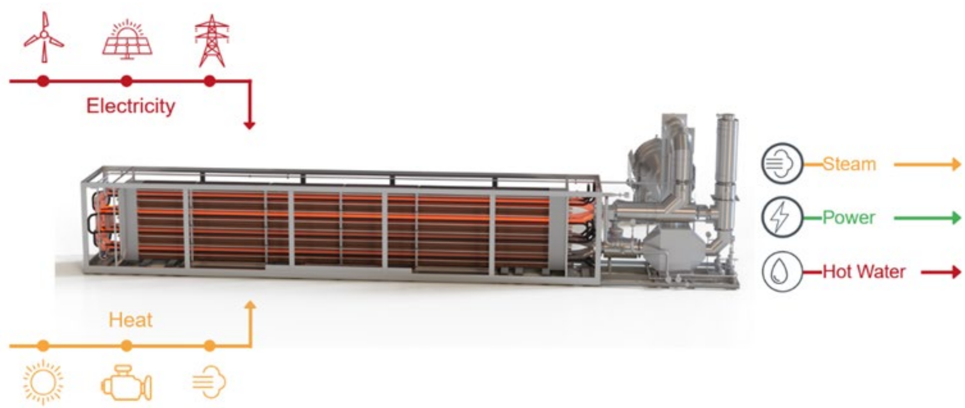


Figure 5-9. Flexible charging and discharging options for bGen™

The main patented technology is for a high temperature energy storage system that is based on crushed rocks, and combines three elements: a heat exchanger, thermal storage, and a steam generator (including superheated steam output). The bGen^{TM} unit has low costs, minimal maintenance and no requires no service for 30 years, therefore driving the price of storage lower. The storage medium is selected for properties conducive to economical sensible heat storage. The unit is built from multiple separate units called bCubes^{TM}, each enabling the exchange of heat, converting electricity to heat, and producing steam.

Thus, 4 main functionalities are embedded within the bGen™ unit: heat exchanging, heat storage, the steam generator and electricity conversion into high temperature heat. Charging of the bGen™ module may be accomplished by flowing the charging heat transfer fluid as steam, combustion turbine (CT) flue gases, or hot air through a tubing set that runs among the units of the bCubes^{TM}. There is no direct contact between the charging fluid and crushed rock, which is sealed within the bCubes^{TM}. Separate tubes allow the heat recovery asynchronously to the charging channels, in the form of steam, hot water, or hot air.

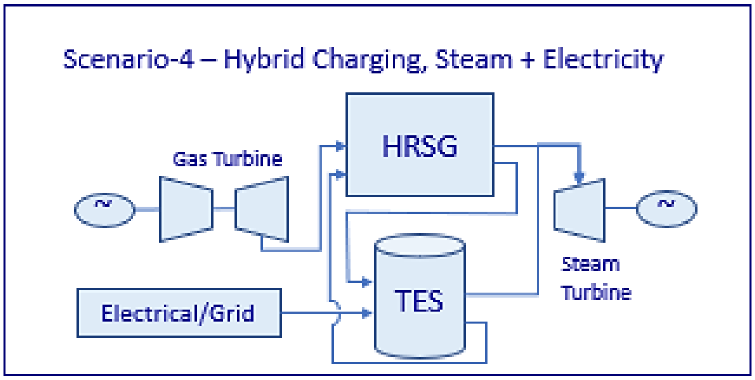


Figure 5-10. Hybrid Charging (Scenario 4)

Figure 5-10 presents the capability of the technology to utilize a hybrid approach to charge the TES from both thermal and electrical sources, including during different asynchronous time slots, while having an accumulated storage buffer from both the collected thermal and electrical streams. The hybrid charging configuration enables the TES to charge usign a flow of superheated steam from the existing power plant's heat recovery steam generator (HRSG), and top it with additional charging from electricity, which may be locally produced or taken from the grid. The topping with converted electricity to high-temperature thermal storage inside the TES enables high-temperature discharge that supports the direct production of superheated steam at the required conditions for steam turbines.

Minimizing the capital investment can be achieved by sharing the piping for charging or discharging of the TES. Electrical charging can be performed at any time. The ratio of electrical charging versus thermal charging can be dynamically set and optimized over time with the changing penetration of renewable energy and fluctuations in market prices.

In addition to what has been described above, the following list includes the main benefits and advantages of the bGen™ TES technology, compared to other technologies and competing approaches:

- Multiple high-temperature fluid (HTF) types are supported by this technology, allowing charge and discharge with different HTFs such as steam, flue gas, air, liquid, and electricity. Other solutions may support only one HTF (e.g., air) due to the direct contact design.
- Prior testing and development work by Brenmiller justifies bGen™ TES as a maturing energy storage technology that has the potential to be integrated into large-scale fossil assets.
- The modular nature of the bGen™ supports future expansion and variable application scale.
- The simple and robust bGen™ design supports a 30+ year life, for long-term reliability.

- The hybrid built-in ability to obtain both heat from a thermal process and electrical heating, allows the TES system to provide value even if the heat from the fossil-fueled power plant is no longer available in the future.
- Integration with NGCC plants increases the overall maximum output, i.e., bGen™ modules discharge to a relatively larger steam turbine than is normally paired with a given gas turbine.
- Integration with NGCC plants can reduce the overall minimum load, by allowing the bGen™ modules to charge while the gas turbine runs at moderate load.
- Projected costs for the TES module are < $50 / kWhth – lower cost than some other solutions.
- The bGen™ concept supports storage temperatures up to 700°C in charging, enabling higher energy density (due to higher temperature difference) per volume, allowing smaller footprint energy storage units.
- Hybrid charging capability inherent in this technology allows the TES to be charged with multiple sources simultaneously, including electricity, steam, and flue gases.

5.2.5 Competition

5.2.5.1 Comparison

The following Tables outline the main features and capabilities of the current existing technologies which can be considered as direct competitors to the bGenTM energy storage technology.

The market potential for the bGen™ technology is divided for 2 segments:

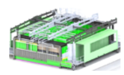
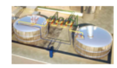
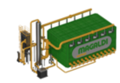
1. Industrial utilization of the bGen™ technology (Table 5-4)
2. Utility power segment utilization of the bGen™ technology (Table 5-5)

Table 5-3. Industrial Segment Energy Storage Comparison

Steam Supply to Industry 	 **Brenmiller Energy bGen™**	 **Electric Steam Boiler**	 **Biomass Steam Boiler**	 **Heat Pump**	 **Sensible Materials**	 **Concrete**
Storage Technology	Sensible Crushed Rock	Resistive Heating No Storage	Biomass Fire tube No Storage	Various heat pumps No Storage	Sensible Steel Slag	Sensible Cement Sleeves
Steam Generator Inside	Yes	Yes	Yes	Future	No	No
Output Temp. [°F]	250-1020	250-570	250-570	Current < 180	250-2000	250-750
Sizes Range [Mw]	0.25 - 100	0.1 - 70	0.1 - 35	0.25 - 40	4-60	0.5 - 100
Hybrid Charging	Yes	No	No	No	No	No
Efficiency E2H	95%	95%	80%	90% - 150%	80%	80%
Modular Design	Yes	No	No	No	Yes	Yes
TRL Status	6	9	9	9	5	6
Challenges	Weight / Volume	Cost to Grid	Ash & Maintenance	Limited Temperature	Storage Media Stability	Concrete Stability

Table 5-4. Utility Power Segment Energy Storage Comparison

Steam Supply to Utilities

	 **Brenmiller Energy bGen™**	 **Full Rocks**	 **Molten Salt**	 **Silica Media**	 **Containerized Sensible**
Storage Technology	Stacked Sensible Crushed Rock, No Contact	Sensible Tanks Full Stones, Direct contact	Sensible Tanks Moten Salt	Phase Change Silicon	Sensible, Containers Silica Sand
Steam Generator Inside	Yes	No	No	No	Yes
Output Temperature [°c]	570-1020	570-1020	570-1020	570-2550	470-1100
Hybrid Charging	Yes	No	No	No	Yes
Efficiency E2H	95%	80%	80%	80%	85%
Modular Design	Yes	No	No	No	Yes
TRL Status	6	6	9	5	5
Challenges	Weight / Volume	Output Stability	High OPEX	Narrow Segment	Uniformity, Losses

The industrial segment comprises the various production operations where process heat is required at temperature ranges of 300 to 850 F. Pressures in this segment are in the range of 90 to 170 psi. A major target has been defined for this segment to move to electrification of the heat with a special target for renewable penetration. The focus on this segment is built from the challenge of reduction of emissions in the production floors, knowing that energy storage for this target is a must.

The Utilities segment is characterized by a demand for heat at temperatures which are in the range of 650 to 1100 F. High pressures are typically required for this segment, in the range of 1100 to 1900 psi.

5.2.5.2 Techno-economics Calculation

The objective of the techno-economic task under this award was to evaluate the cost and performance for a commercial-scale application of the bGen^{TM} TES technology, when integrated with a fossil fuel power plant. Costs were estimated using a bottom-up costing approach in conjunction with an experienced engineering company to improve the validity especially for off-the-shelf balance of plant equipment and systems.

During the conceptual design study, the project team analyzed four different potential scenarios, to be installed at the NYPA Zeltmann power plant in Astoria, New York. The scenarios range from a pure thermal charging of the TES using hot flue gases from the two onsite combustion turbines, up to a full charging of the TES with an electrical source, and also a scenario utilizing the hybrid charging capability of the bGen™. The utilized electrical sources are the local produced electricity or the future renewable electricity from the grid.

Scenario #4, hybrid charging, was selected as the basis for the techno-economic assessment. The bGen™ ability to charge and discharge from both the thermal and the electrical sources creates a device that stores low-value, off-peak energy and re-injects that energy into the facility steam cycle to boost steam turbine generator ("STG") during periods of high electricity demand/prices. Charging with steam comes at the cost of reduced electricity output in the STG. The analysis includes 75% charging of the TES capacity from the thermal HTSG steam, and 25% charging from the electrical source. The ratio of electricity used for charging is assumed to grow along with the renewable energy penetration on the grid. The analysis is based on 4 hours of charging and 4 hours of discharging.

For optimization of the required CAPEX investment in this scenario, this hybrid scenario was designed to enable only thermal charging or discharging at the same time. No parallel charging and discharging of superheated steam. Such a design enables multiple cycles per day, depending on the selected TES size. Electricity can be used for charging the TES at any time, during charging or discharging and especially at off peak time slots.

Design and Cost Basis

The Brenmiller technology was analyzed for an installation at NYPA's Eugene W. Zeltmann Power Plant (Zeltmann), a natural gas combined cycle (NGCC) power plant.

A storage capacity of 200 MWh thermal was selected to enable the utilization of the existing installed capital equipment at Zeltmann plant for the incremental power produced by the TES, with no need to increase the capacity of the existing steam turbine.

The storage system is designed to charge and discharge from both thermal and electrical sources. This creates a device that stores low-value, off-peak energy and re-injects that energy into the facility steam cycle to boost steam turbine generator ("STG") during periods of high electricity demand/prices. Charging with steam comes at the cost of reduced electricity output in the STG.

The storage system is based on 4 hours of charging and 4 hours of discharging at the rated discharge steam flow and electric output. There is no requirement for continuous discharging or charging. Thermal charging or electrical charging time slots can be asynchronous.

The initial split of charging assumes 75% charging of the TES capacity from the thermal HTSG steam, and 25% charging from the electrical source. The ratio of electricity used for charging is assumed to grow along with the renewable energy penetration on the grid.

This cost estimate for this project is defined as an AACE Class IV estimate which has typical accuracy ranges of -15% to -30% on the low side and +20 to +50% on the high side, based on AACE International Recommended Practice No. 18R-97.

The capital cost for the bGen™ storage modules and other major storage system components were provided by Brenmiller Energy. The cost estimate was based on 692 bCube ™ modules, which would be needed for the 200 MWh energy storage capacity of the selected scenario.

United E&C was responsible for all balance of plant (BOP) scope. This included engineering (all home office services), procurement, construction management, and startup and commissioning. United developed this estimate utilizing a construction subcontract approach. Process flow diagrams were developed, and a general arrangement drawing was developed for Scenario 4.

Engineering services and home office support services during construction are included in the estimate based on a percentage. Owner's costs were not included in the overall estimate

Capital and O&M Costs

Table 5-5 details the required investment for this scenario and is based on the use of 692 bGen™ modules.

Table 5-5. Capital Cost Summary for Scenario 4 – Hybrid Charging

Configuration main blocks – Cost	$ M
200MWh bGen™ Storage	$9.0
BOP Connection and Commissioning	$13.3
Total Cost	**$22.3**

It is assumed that the existing operations team at the Zeltmann plant will take control of the TES operation at no additional cost. All the additional installed balance of plant equipment will be maintained by the local power utility staff. Annual maintenance cost for the TES storage modules is estimated to be approximately 3% of the TES cost (without BOP), or $258,737 per year.

In the NYISO market, energy storage resources are eligible to receive different levels of capacity credits at discharge duration periods from 2 to 8+ hours.

The following potential revenue streams are valid for this scenario's energy calculation:

6. Energy arbitrage based on historical real time prices

7. Additional margin for optimization of the Day Ahead (DA) prices with the real time prices

8. Ancillary services

9. Margins resulting from the penetration of renewables and carbon credits prices

10. Capacity payments for a storage system in the NYISO arena, last guidelines

Values of these revenue streams are presented in Table 5-6 for the year 2023.

Table 5-6. Potential Energy Arbitrage and Capacity Value of bGenTM Storage

Sources of Increased Value of Storage (2023)	Energy Margin $/kW-mo
Deployment based on historical RT prices (4-hr storage)	$4.06
Combination with DA activity + Overall optimization	$1.58
Ancillary services	$0.26
Renewable's penetration, less carbon in off-peak prices	$0.50
Capacity Revenues (Net of ICAP/UCAP and derating factors)	$5.13
Total Energy Margin + Capacity Payment	**11.53**

Table 5-75-8 shows the internal rate of return analysis for Scenario 4. The cash flow analysis shown in Table 5-8 forecasts the overall project revenue and expenses for future years. The year-by-year cash flows assume an annual O&M escalation rate of 2%, while the revenue/energy margin rates are assumed to escalate by 2.5%.

Note that the percentage of electric charging increases over time due to the increasing price volatility and real-time margins. This means that there will be more hours to charge at lower, or even negative, prices. Charging electric power cost starts at $10/MWh in 2023 and decreases to -$20/MWh by 2050.

Table 5-7. Project IRR – Scenario #4 – Source of charging energy: Hybrid Steam and Electricity

		2023	2033
Operating Parameter			
Power Gen capability	kW	17,800	17,800
Electric storage capability	MWh	71.2	71.2
Derated/Adjusted capacity	kW	15,120	15,120
Assumed cycles per day	cycles/day	1.5	1.5
Selling hours	%	1,971	1,971
Annual generation	MWh	35,084	35,084
Hybrid electrical charging		25%	60%
Revenues/Margins			
Real time margin	$/KW/mo	4.06	10.06
Adder for DA and optimization	$/KW/mo	1.58	2.02
Inc. volatility + Renewables + CO2	$/KW/mo	0.5	8.41
Ancillary services	$/KW/mo	0.26	0.33
Capacity price	$/KW/mo	5.13	6.57
Total revenues	**$/KW/mo**	**11.53**	**27.38**
Anuual revenues			
Real time margin	$/yr	867,288	2,147,806
Adder for DA and optimization	$/yr	337,488	432,013
Inc. volatility + Renewables + CO2	$/yr	106,800	1,795,308
Ancillary services	$/yr	55,536	71,091
Capacity price	$/yr	930,787	1,191,486
Total revenues	**$/KW/mo**	**2,297,899**	**5,637,704**
Operating cost			
Variable operating cost	$/yr	29,237	35,640
Fixed operating cost	$/yr	229,500	279,759
Net cash flow	$/yr	**2,039,162**	**5,322,305**
Investment	$	22,261,326	
Project IRR	%	**16.6%**	

Table 5-8. Scenario 4 - Cash Flow Analysis for Scenario 4

		2023	2024	2025	2026	2027	2028	2029	2030	2050	2051	2052
Operating Parameter												
Power Gen capability	kW	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800	17,800
Electric storage capability	MWh	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2
Derated/Adjusted capacity	kW	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120
Assumed cycles per day	cycles/day	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Selling hours	%	1,971	1,971	1,971	1,971	1,971	1,971	1,971	1,971	1,971	1,971	1,971
Annual generation	MWh	35,084	35,084	35,084	35,084	35,084	35,084	35,084	35,084	35,084	35,084	35,084
Hybrid electrical charging		25%	27%	29%	31%	34%	37%	40%	45%	90%	90%	90%
Revenues/Margins												
Real time margin	$/KW/mo	4.06	4.38	4.74	5.14	5.59	6.10	6.67	7.38	12.43	12.46	12.48
Adder for DA and optimization	$/KW/mo	1.58	1.62	1.66	1.70	1.74	1.79	1.83	1.88	3.08	3.15	3.23
Inc. volatility + Renewables + CO2	$/KW/mo	0.5	1.5	2.5	3.5	4.5	5.5	6.5	7.5	12.79	13.11	13.44
Ancillary services	$/KW/mo	0.26	0.27	0.27	0.28	0.29	0.29	0.30	0.31	0.51	0.52	0.53
Capacity price	$/KW/mo	5.13	5.26	5.39	5.52	5.66	5.80	5.95	6.10	9.99	10.24	10.50
Total revenues	**$/KW/mo**	**11.53**	**13.03**	**14.56**	**16.15**	**17.79**	**19.49**	**21.25**	**23.16**	**38.80**	**39.48**	**40.18**
Anuual revenues												
Real time margin	$/yr	867,288	935,913	1,012,905	1,098,238	1,194,992	1,303,944	1,425,044	1,576,156	2,655,986	2,660,792	2,665,717
Adder for DA and optimization	$/yr	337,488	345,925	354,573	363,438	372,524	381,837	391,383	401,167	657,359	673,793	690,638
Inc. volatility + Renewables + CO2	$/yr	106,800	320,400	534,000	747,600	961,200	1,174,800	1,388,400	1,602,000	2,731,773	2,800,068	2,870,069
Ancillary services	$/yr	55,536	56,924	58,348	59,806	61,301	62,834	64,405	66,015	108,173	110,877	113,649
Capacity price	$/yr	930,787	954,057	977,908	1,002,356	1,027,415	1,053,100	1,079,428	1,106,413	1,812,987	1,858,312	1,904,770
Total revenues	**$/KW/mo**	**2,297,899**	**2,613,220**	**2,937,734**	**3,271,437**	**3,617,432**	**3,976,515**	**4,348,659**	**4,751,752**	**7,966,279**	**8,103,842**	**8,244,844**
Operating cost												
Variable operating cost	$/yr	29,237	29,822	30,418	31,027	31,647	32,280	32,926	33,584	49,904	50,902	51,920
Fixed operating cost	$/yr	229,500	234,090	238,772	243,547	248,418	253,387	258,454	263,623	391,730	399,565	407,556
Net cash flow	**$/yr**	**2,039,162**	**2,349,308**	**2,668,544**	**2,996,864**	**3,337,367**	**3,690,848**	**4,057,279**	**4,454,544**	**7,524,645**	**7,653,375**	**7,785,367**
Investment	$	22,261,326										
Project IRR	%	**16.6%**										
Project cash flow	-22,261,326	2,039,162	2,349,308	2,668,544	2,996,864	3,337,367	3,690,848	4,057,279	4,454,544	7,524,645	7,653,375	7,785,367

Economic Assessment

Looking ahead to the power generation mix in future years and recognizing that there are limitations on installation of new capital equipment, it is evident that the optimum scenarios must be ready for integration of renewable electricity from the grid. The hybrid steam/electric design described in this study enables a gradual shift from thermal charging sources to electrical charging (from renewable sources).

The hybrid steam/electric charging scenario evaluated in this study looks quite favorable. The following principles characterize this scenario:

- Charging the TES with superheated steam from HRSG
- Topping with partial electricity charging to enable high temperature steam output to steam turbine
- Utilizing the residual low temperature steam during charging back to the HRSG
- Using the same piping for charging and discharging of steam (for cost reduction)
- Enabling charging with electricity at any given time
- Reaching an IRR of more than 16% at the Zeltmann site with 200 MWh of storage

6.0 TECHNOLOGY MATURATION PLAN

6.1 Introduction

Brenmiller Energy of Rosh HaAyin, Israel, has developed a modular, containerized thermal energy storage (TES) system, known as bGen™, capable of accommodating both thermal and electrical inputs and generating steam or hot water [1]. The storage medium is crushed rock, which is selected for specific properties conducive to economical sensible heat storage. This TES system has been developed by Brenmiller Energy over the last 8 years and has been tested in 3 generations of demonstration units at various sites, globally. Brenmiller Energy expects a bGen™ module will have a 30-year life without any replacement of the storage media. The bGen™ modules are configured in a manner that allows interconnection both vertically (i.e., in a stack) and horizontally to build systems ranging in thermal capacity from 0.5 MW-th to 1.0 GW-th. The modules' operation is configurable, so the thermal or electrical input runs through all or some of the modules during charging or discharging. Targeted applications of this crushed rock TES system include renewables integration and grid support; decoupling of the time of electricity and thermal energy supply in combined heat and power (CHP) systems; power-to-heat applications where there are sharp swings in the cost of electricity from off-peak to peak; and the ability to independently operate the gas turbine and steam turbine for flexible power generation in natural gas combined cycle (NGCC) plants. In the latter application, the bGen™ module effectively acts as the NGCC plant's heat recovery steam generator (HRSG).

6.1.1 Process Description

The bGen™ technology, is a modular crushed-rock TES system that can be charged from both thermal and electrical inputs, and can output steam, hot water, or hot air, as shown in Figure 6-1. Charging of a module is accomplished by electrical resistance heating, or by a fluid (e.g. heated oil, steam, hot water, or hot flue gases) flowing through tubing set among the crushed rock. There is no direct contact between a charging fluid and the crushed rock. A representative module, without the exterior container, is shown in Figure 6-2.

Figure 6-1. Flexible charging and discharging options

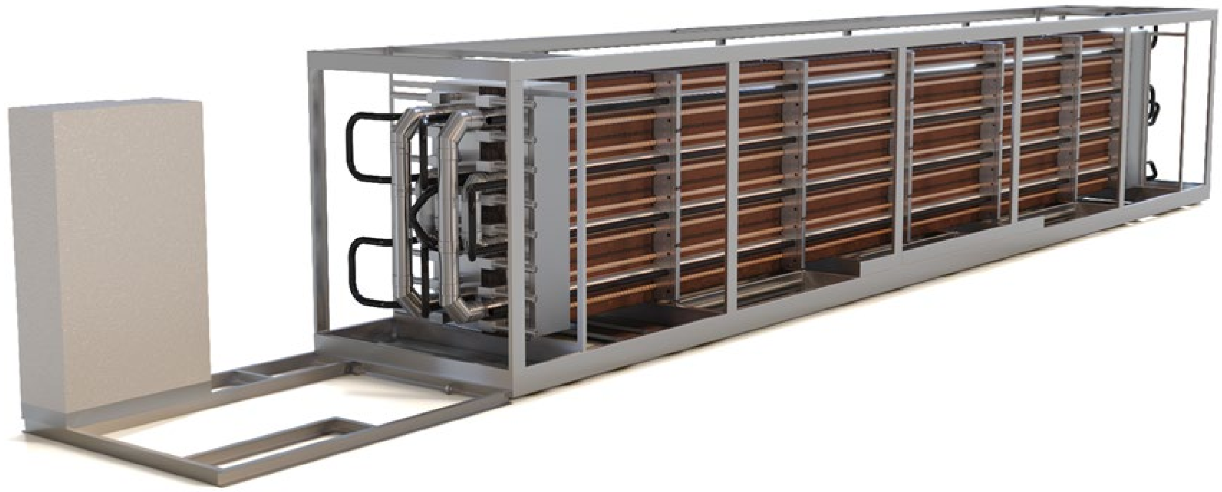


Figure 6-2. Artist's rendering of a Brenmiller Energy bGen^{TM} thermal storage module

The main patented technology includes a high temperature energy storage system based on crushed rocks, which combines three elements: a heat exchanger, thermal storage and a steam generator. The bGen^{TM} unit is claimed to have low costs, minimal maintenance and requires no service for 30 years. The typical output capacity for a bGen^{TM} module in a power generation application will be about 2 MW-th. The storage medium is selected for properties conducive to economical sensible heat storage. The projected installed cost of the TES system is projected to be less than \$50 /kW-th. The unit is built from multiple separate units called bCubes, each enabling the exchange of heat, converting electricity to heat and producing steam. Each bCube is about 20 in. (0.5 m) square by 40 ft (12 m) long. The bCubes are visible in Figure 6-3. Each bCube contains horizontal and vertical tubes for effective heat transfer and interconnecting piping that supports stacking and horizontal interconnection of multiple bGen^{TM} modules. These bCubes are assembled into bGen^{TM} module, which are designed to fit in a standard 40-ft (12 m) shipping container, as shown in Figure 6-4. The modules can accommodate charging fluid temperatures up to 1300°F (700°C), but for temperatures above 1050°F (565°C), special high-temperature alloy tubing is needed. If flue gas is the charging fluid, corrosion-resistant tubing is used if the exit gas temperature will be at or below the dew point.

Figure 6-3. Photo of a Brenmiller Energy bGen^{TM} thermal storage module internals (bCubes)

Figure 6-4. Containerized bGen^{TM} thermal storage module

6.2 Technology Readiness Level

The Brenmiller Energy bGen^{TM} crushed rock TES system has been evaluated to assess the Technology Readiness Levels (TRL), using the criteria defined by the U.S. Department of Energy, as shown in the Appendix (Table 6-4). The evaluation of current TRL score includes a review of prior development work, as well as other simultaneous supporting activity. The assessment of TRL score at the end of the proposed work scope is based upon the assumption of a successful outcome of the proposed effort.

6.2.1 Technology Status

Brenmiller Energy has a working proof-of-concept for the storage system, which has been tested, verified, and validated at the Rotem demonstration site in the south of Israel. This test rig demonstrated the ability to operate the bGen^{TM} system for a prolonged amount of time and to achieve performance goals. In this test, the salient performance parameters were stable production of superheated steam at high temperature and pressure, storage heat capacity, storage discharging rate, overall storage heat transfer coefficient, and low storage heat loss.

As of September 2018, the demonstration has shown a prolonged steady production of steam, for a duration of 8 hours, at temperatures up to 970°F (520°C) and at a pressure of about 1160 psig (80 barg), as shown in Figure 6-5. The brief pressure dip seen in the graph is related to startup of the discharge cycle when pressure builds up from 0 to 1160 psig (0 to 80 barg). The steam is delivered to users at the end of the startup stage when it reaches operating conditions.

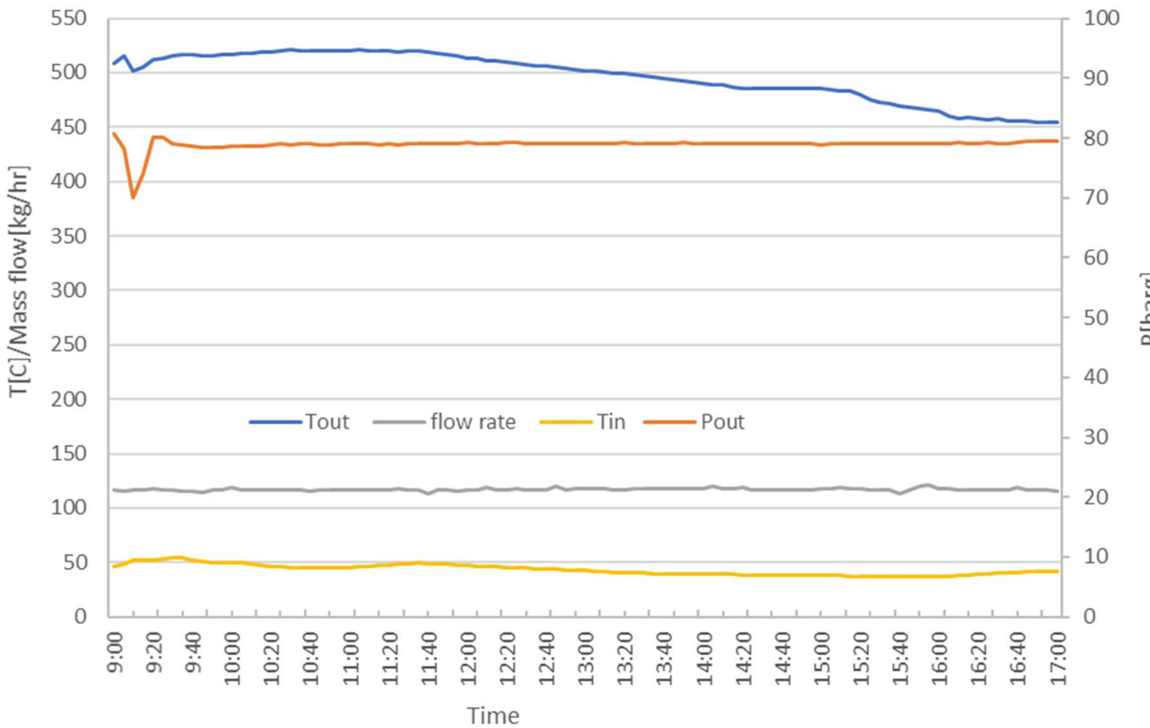


Figure 6-5. Brenmiller Energy bGen^{TM} pressures, temperatures, and flow rate during an 8-hour discharge cycle

Brenmiller Energy is supplying its energy storage technology at 1.7-MWe scale as part of the Rotem 1 Concentrated Solar Power (CSP) in the Negev desert, which is scheduled to begin grid-connected operation in 2021. The addition of storage will allow the plant to generate electricity for up to 16 hours per day. Potential addition of natural gas could allow the unit to operate up to 24 hours per day. A successful demonstration will allow bGen^{TM} technology to achieve a technology readiness level (TRL) of 9 at this small scale, as Rotem 1 is a commercial project with a 20-year power purchase agreement with the Israel Electric Corporation. Relative to the ultimate utility scale of hundreds of MWhe, bGen technology will be at a TRL of 6 following successful operation at Rotem 1.

Separately, Brenmiller Energy is conducting a pilot project with the New York Power Authority (NYPA) at 1-MWth scale that pairs a bGen^{TM} TES module with a microturbine in a CHP application to improve energy efficiency and provide flexibility in extreme conditions on a State University of New York campus, including operation independent of the grid [2, 3, 4]. Startup is scheduled for mid-2021. A 3D rendering of the TES system to be used for the CHP integration is shown in Figure 6-6.

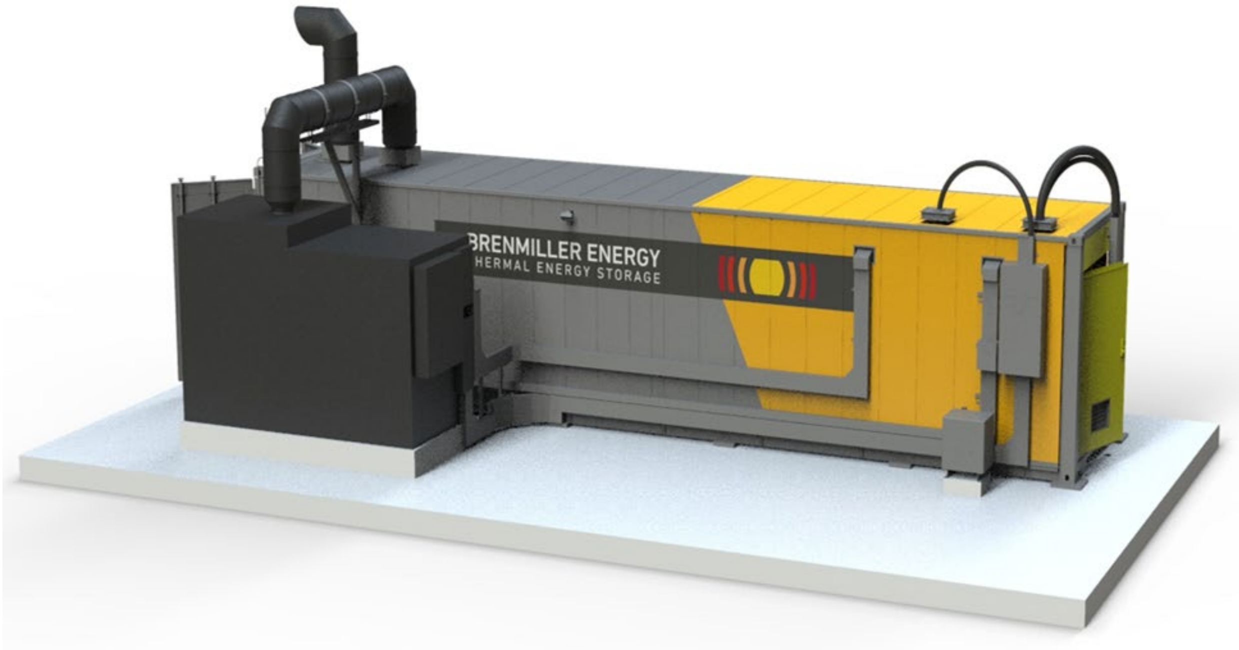


Figure 6-6. Brenmiller Energy bGen™ as planned for integration with NYPA

Table 6-1 details various development projects by Brenmiller Energy, and their corresponding status. These projects are built at prototype scales for various market segments, such as the industrial segment for medium to high temperatures, the power utility segment, and the CHP commercial segments. Final installation and commissioning of each of these prototypes is intended to advance the technology readiness for each of the related segments, utilizing the core technology of the bGen™ system.

Table 6-1. Status of other projects undertaken by Brenmiller Energy

Site / Customer	Market Segment	Development Stage	Power	Capacity	Planning	FEED	Construction	Commiss-ioning	Operations
ENEL Italy	Power Utility	Commercial Pilot	5MW	24MWh	Completed	Completed	Sep 2021 – Nov 2021	Dec 2021 – Mar 2022	2022
FORTLEV Brazil	Industrial Mid. Temp	First Commercial Deployment	400KW	2MWh	Complete	Completed	Jun 2021 – Oct 2021	Nov 2021 – Dec 2021	2022
SUNY US	Cogen Commercial	First Commercial Deployment	500KW	510KWh	Jan 2020 – Jun 2021	Completed	Jul 2021 – Aug 2021	Sep 2021 – Oct 2021	2022
IDF Israel	Industrial Mid. Temp	First Commercial Deployment	150KW	450KWH	Completed	Completed	Completed	Completed	Mar 2021
ZELTMANN US	Power Utility	Commercial Pilot	4MW	16MWh	Apr 2021 – Aug 2021	2022	2023	2024	2025

6.2.2 Commercial Application

Fossil fuels continue to be the main source of power generation in the U.S. In recent years, the relatively low cost of natural gas has allowed it to overtake coal as the dominant fossil fuel in the U.S. In addition, continued growth in power generation from variable renewable energy (VRE) sources challenges the stable operation of the power transmission and distribution system. The addition of energy storage to increase the flexibility of the fossil generation assets can help to address this challenge. The increased flexibility could support the further growth in integration of VRE sources, while maintaining stability and backup reserves for the electrical grid. The scalability of the Brenmiller bGen^{TM} TES technology provides the opportunity for direct application to NGCC and other fossil generation assets that would benefit from increased flexibility due to VRE, across a wide range of plant sizes, and addresses thermal capacity storage needs from 0.5 MW-th to 1.0 GW-th.

TES is a natural fit for thermal plants as they are both use thermal energy, helping to minimize conversion losses. The bGen^{TM} technology offers unique qualities to meet the needs and challenges of supporting flexibility and grid stability. In addition to offering relatively low cost per MWh and robustness, the technology can be deployed in modules to adapt to various plant sizes. The bGen^{TM} technology can combine multiple thermal and electrical inputs, resulting in enhanced flexibility to both the plant's thermal cycles (gas, steam) and to the electrical side, as shown in Figure 6-1, as well as in Figures 6-7, 6-8, and 6-9.

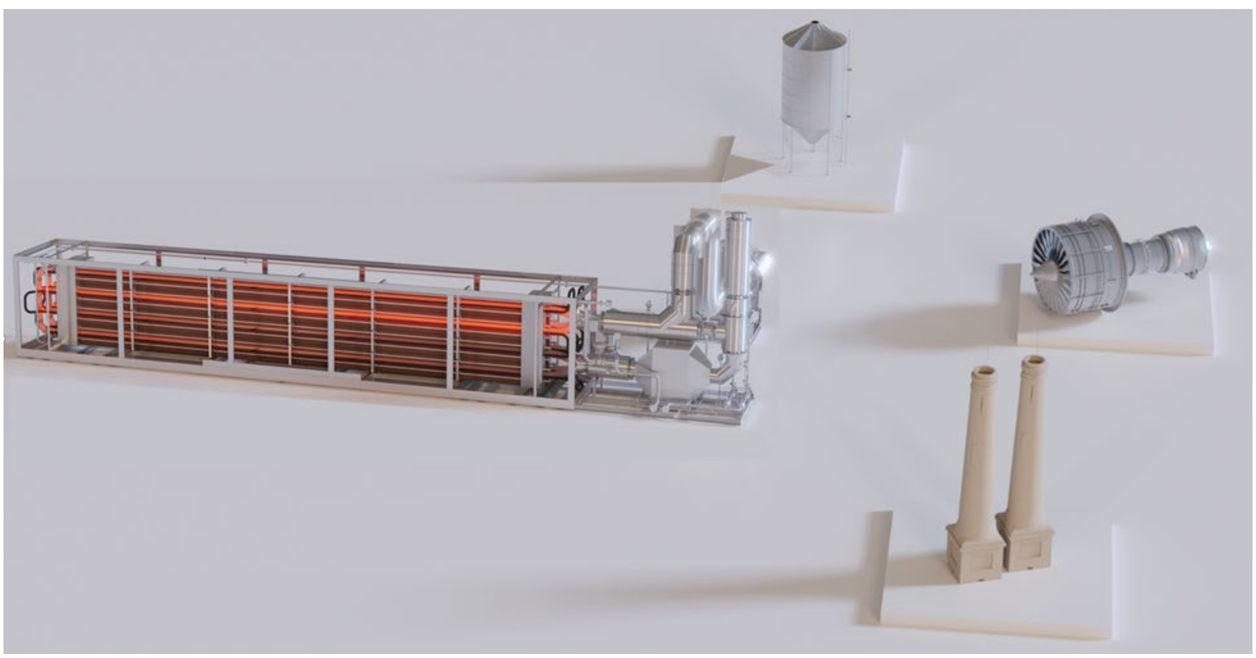


Figure 6-7. Thermal Charging of TES

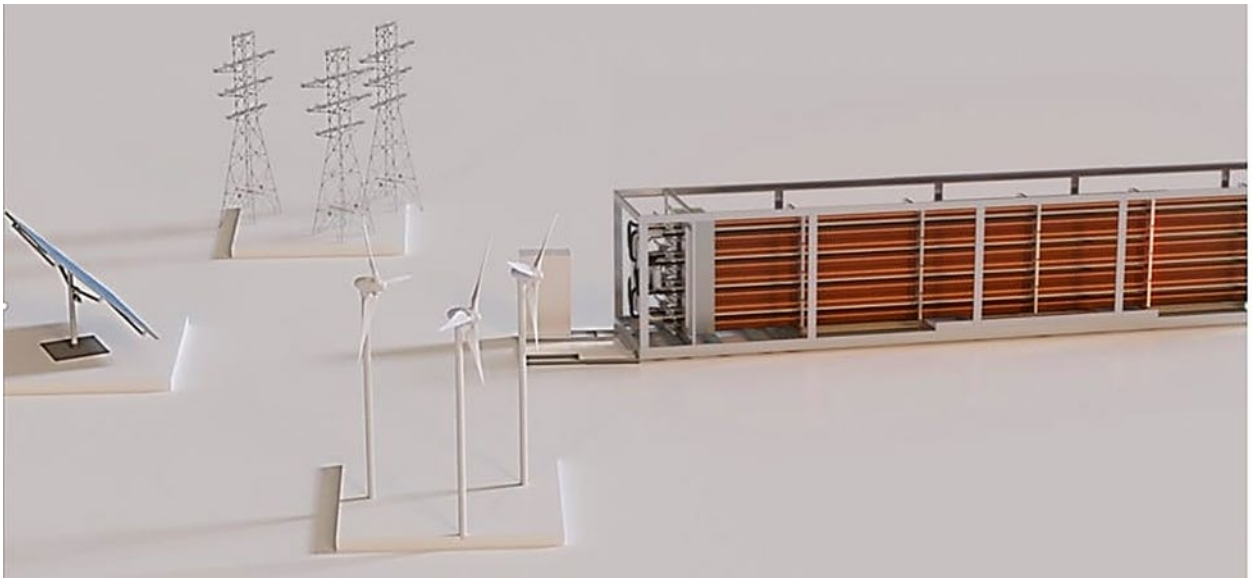


Figure 6-8. Electrical Charging of TES

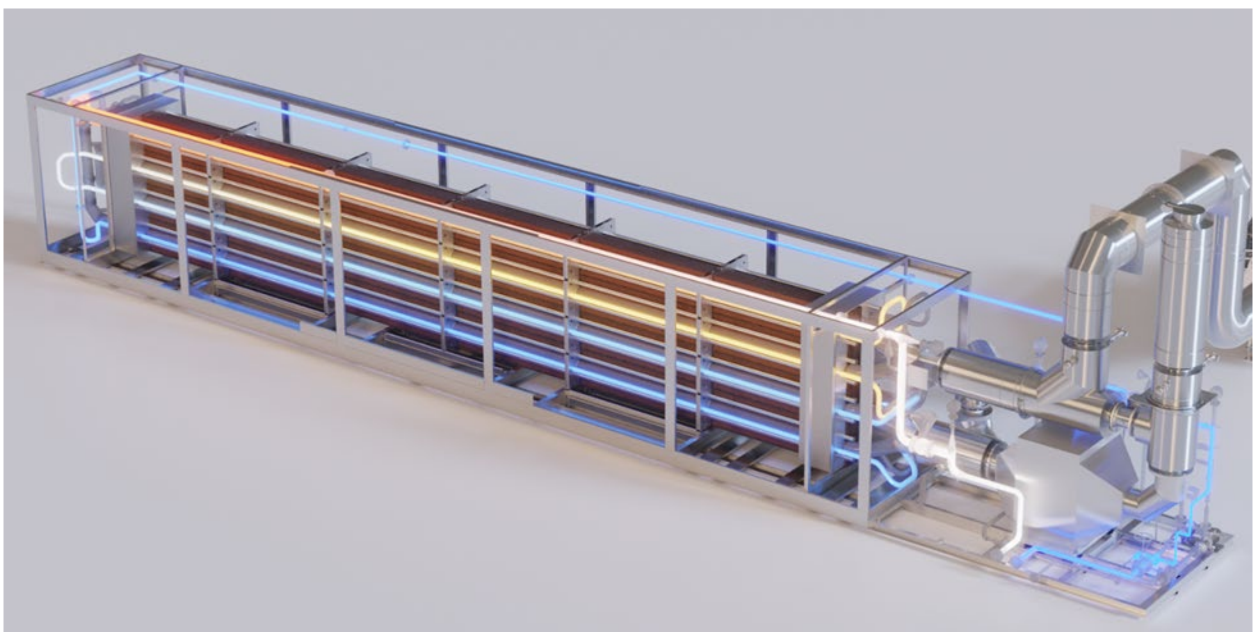


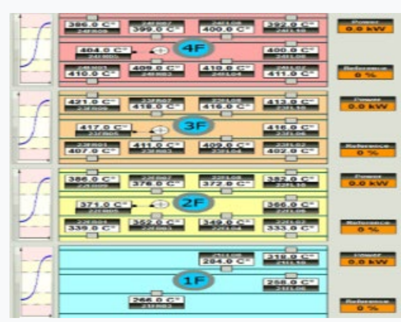
Figure 6-9. Steam Discharging from TES

6.3 Proposed Work

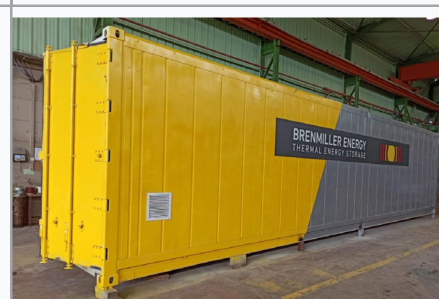
The tasks proposed to be performed under the current project award are intended support a next-step pilot, which would advance the TRL of the crushed rock TES technology. If the effort is successful, the technology would advance from TRL 5 to TRL 6.

The proposed work builds upon the prior efforts of Brenmiller Energy, including multiple stages of pre-design, demonstration prototypes, lab testing, charging with multiple sources and measuring of output results. Table 6-2 summarizes various milestones and results for the crushed-rock TES system that have been achieved to date:

Table 6-2. Prior Development Activities, Milestones and Results

Milestone Description	Results	TRL	Time	Picture
Identification of the preferred Storage Media, Crushed Rocks as the viable thermal storage media, Building a Lab Testing Device.	Experimental evidence showing 90% performance with the required thermal conductivity and storage density on a lab scale compared to the other materials tested. Other analyzed materials included Stones, Concrete, Lava Rocks, Sand and PCM, Phase Change Materials. The built testing device was designed to enable measurements of heat transfer efficiency, of edge effects, possible charge and discharge cycles and special effects during charging and discharging.	2	March 2015	
Experimental proof of concept developed with a detailed technical specification and a test unit to screen different modes of operation.	Proof of concept was used to form and improve the bGen^{TM} system design, identify the technical issues and arrive at solutions to be tested with a prototype. Technical requirements were set for both the feasibility stage and the preliminary design. The aim of the measurements and proof of concept	2	January 2016	

	was to find the real values, compared to the set targets in the technical specification. Hundreds of sensors were installed in different positions inside the testing device, enabling a full analysis during different phases of the storage cycles. Graphs were prepared to show feasibility.			
Initial prototype of working bGen™ system for in house testing. Selected configuration was an underground system utilizing a CSP charging loop.	The prototype was built in Rotem, South of Israel. The inputs were energy produced from a CSP thermal solar loop. The storage system was built underground as a 100 meters system, to reduce plan area and better integration in existing fields. The unit went through 5 months of testing for thermal conductivity, mechanical expansion, inherent steam generation and interface learning topics. Results were analyzed and used for the decision of the next stage and prototype building. The usage of an underground system was found to be complex and not advantageous.	3	June 2017	

bGen^{TM} system validated at Rotem plant site, were a direct grid connection was used to charge the system, planning to supply the output to the Rotem customer.	The configuration for this site was selected to be of a 12 meters block design, charged with the grid energy and supplying steam at its output, according to the demand time slots. The special interface to the grid was tested, curves of heat loss, steam generation stability, start-up and shut-down times were created to finalize the learning curve of the system. The system performed according to specification and supplied steady steam for more than 8 hours, as designed. The units of the system were manufactured by Brenmiller at a new factory, located in Dimona, south of Israel. A full engineering product tree was created including all drawings.	4	August 2019	
Pilot project at an Israel Defense Forces (IDF) remote base facility to demonstrate the system in a real environment.	The Israeli IDF has remote bases where supply of high amount of heat at short times has been required. The company has built the unit and installed it at the site. The charging of the unit is from residual flow gas	5	March 2020	

	from existing generators and the output, on demand, is high amount of heat at short bursts in time. The infrastructure was prepared by the IDF, the company installed the system and running according the defined specification. The system has been manufactured in Brenmiller's factory in Dimona, Israel while the raw materials were purchased in Europe and Asia. The company is guiding the operation of the system.			

The work to be executed under this project includes preparation of several scenarios for the NYPA Zeltmann power plant. Each scenario will be calculated to present the results and outcome of the target merit and performance parameters of these scenarios. These calculated parameters will include the storage charging capabilities, the energy losses, the capacity, the emissions reduction, and the power supply capabilities. Table 6-3 presents an example of the performance data to be calculated for each scenario.

Table 6-3. Representative example of performance parameters

Parameter	Units	Operation		
		Min. Value	Ref. Value	Max. Value
Charge cycle				
Flow rate	Kg/h			
Power	MWt			
Charging time (@ given flow)	hours			
Discharge cycle				
Flow rate	Kg/h			
Power	MWt			
Discharging time (@ given flow)	hours			
Other Performances				
Total Storable Energy	MWt hour			
Thermal Energy losses	%/day			
Charging time from cold	hours			
Cold condition TESS media temperature	°C			

6.3.1 Objectives of Current Project

The goal of this project is to design a next-step pilot to advance near-term energy storage integrated with a fossil plant to provide a facility capable of being viable and effective in a market with growing penetration of variable renewable energy (VRE). Thermal energy storage (TES) represents an ideal technology for this purpose. The effort under the current project will perform a feasibility study to prepare for the Phase II pre-front end engineering design (pre-FEED) for implementing a crushed-rock TES system integrated with a natural gas combined cycle (NGCC) plant. The crushed rock storage technology, which is being developed by Brenmiller, is a modular TES system termed bGen™, which can accommodate both thermal and electrical inputs and output steam, hot water, or hot air. For this application, the estimated efficiency is 80% thermal to thermal. The market for TES systems is seeking low capital cost, high round-trip efficiency, and low standby energy losses. The current project scope is designed to help address these objectives as part of the next-step pilot plant.

6.3.2 Project Specific Attributes

For the current project, the Brenmiller TES technology will be designed to operate on a slipstream from NYPA's Eugene W. Zeltmann Power Project (Zeltmann) NGCC plant or a similar plant in their portfolio. The projected size of the system will be up to 4 MWe with at least 4 hours of storage duration, or 16 MWh-e total. Final sizing will be determined during the feasibility study. EPRI has reviewed Brenmiller's technology, which is being built to demonstrate bGen™ at 1.7 MWe on a solar plant (Rotem) and has been designed for an

NGCC facility in Italy, assessing it at technology readiness level (TRL) 5. As noted separately, Brenmiller is also conducting a parallel project to deploy a 1-MWth pilot with NYPA that pairs a bGen™ module with a microturbine for a combined-heat-and-power (CHP) application to improve efficiency and provide flexibility.

When integrated with a NGCC plant, the bGen™ TES system is charged with steam, delivered from the final stages of the heat recovery steam generator (HRSG). One of the potential arrangements is shown on the process diagram in Figure 6-10. When the unit is charged, a controlled temperature is maintained, transforming the feed water into steam, which is discharged into the HRSG according to the plant's needs. The embedded heat exchanger, steam generator, and electricity convertor within the bGen™ system eliminates the external heat exchangers, steam generators, and electricity convertors that require an additional cost and special warming-up procedure to synchronize the internal and external temperatures and pressure. The bGen™ can inherently produce the required superheated steam since it is designed to store the heat at temperatures between 500°C and 700°C. This enables a relatively simple interface into the fossil plant.

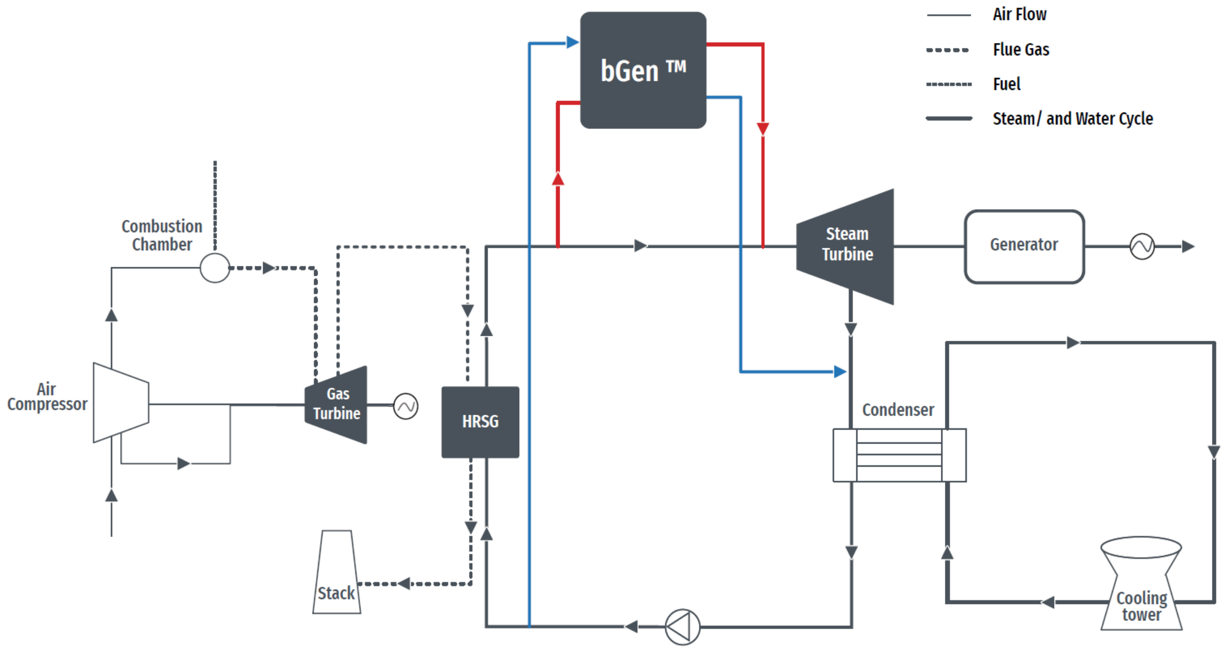


Figure 6-10. Potential Process Diagram for bGen™ Technology Integration with NGCC Power Plant

For the proposed configuration, the estimated efficiency is 80%, on a thermal-to-thermal basis. The unit energy losses are less than 3% per 24 hours of operation and the required operation and maintenance of the unit are minimal due to the passive design of the system. The estimated efficiency and losses can be validated during the next-step pilot testing effort. The planned size of the TES pilot system will be up to 4 MWe with at least 4 hours of storage duration. Final sizing will be determined during the feasibility study.

The next-step pilot being designed as part of the current project will represent a 5-fold increase in scale, versus Rotem, and will show the technology's ability to provide effective and economical energy storage, bringing the technology to TRL 6. This pilot would represent the next-to-last demonstration scale before the technology could be commercial ready at GWh-e scales in the 2030 timeframe. Funding for this project will provide the design for the critical next-step pilot, which will be undertaken in real-world operating conditions to better determine the Brenmiller technology's ability to be integrated with an NGCC plant and assess degradation over transient cycling at rates befitting various marketplaces.

The results of the project are expected to include performance parameters such as the storage capacity per storage size, the resulting losses per hour, its discharging capabilities in regards to power and stability, the capability to have hybrid charging for possible future charging from renewable sources (grid or local), required interfaces to an existing NGCC plant, and the overall advantage of reduction of plant emissions, once integrating the TES.

6.3.3 Key Metrics

The tasks included in the proposed Phase I project have been planned to attain the critical metrics and corresponding targets necessary to allow the bGen™ crushed-rock TES technology to reach the proposed project end state (TRL 6) at the conclusion of next-step pilot testing. The metrics and targets include effective plant integration, low installed cost (<$50 /kWth), high efficiency (80% thermal), reduction in plant emissions (>7%), reduction in electricity price per produced KWh (>5%) and 5-fold increase in the demonstrated scale to support modular scalability.

6.4 Post-Project Plans

The work included in the current project plan is part of the effort needed to advance crushed-rock TES technology toward large-scale commercialization (TRL 9) by the 2030 target date. The next-step pilot would be the subsequent logical step after the currently defined work scope and would advance the technology from TRL 5 to TRL 6.

As part of this effort, the project is expected to assess potential local suppliers for main blocks of the system, potential local EPC companies for the installation challenges, final definition of required integration and commissioning procedures, finalizing the system documentation as training, operation, and maintenance. The overall control of the TES, as an integral part of the plant control will be one the challenges for the project Pre-FEED stage, for integration of the TES into the existing plant, both in defining the required algorithms and in allocating the local companies, capable of implementing these TES integration control algorithms and software. In preparation for commercialization and multiple installations of the TES in NGCC plants, the company will assess the required maintenance capabilities, potential agreements with local maintenance companies and all logistic aspects of the TES installation and shipments to various spots in the US.

6.5 References

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6.6 Appendix – Technology Readiness Levels Defined by DOE

Table 6-4. Technology Readiness Level Definitions

Relative Level of Technology Development	Technology Readiness Level	TRL Definition	Description
System Operations	**TRL 9**	Actual system operated over the full range of expected mission conditions.	The technology is in its final form and operated under the full range of operating mission conditions. Examples include using the actual system with the full range of wastes in hot operations.
System Commissioning	**TRL 8**	Actual system completed and qualified through test and demonstration.	The technology has been proven to work in its final form and under expected conditions. In almost all cases, this TRL represents the end of true system development. Examples include developmental testing and evaluation of the system with actual waste in hot commissioning. Supporting information includes operational procedures that are virtually complete. An Operational Readiness Review (ORR) has been successfully completed prior to the start of hot testing.
	TRL 7	Full-scale, similar (prototypical) system demonstrated in relevant environment	This represents a major step up from TRL 6, requiring demonstration of an actual system prototype in a relevant environment. Examples include testing full-scale prototype in the field with a range of simulants in cold commissioning (1). Supporting information includes results from the full-scale testing and analysis of the differences between the test environment, and analysis of what the experimental results mean for the eventual operating system/environment. Final design is virtually complete.
Technology Demonstration	**TRL 6**	Engineering/pilot-scale, similar (prototypical) system validation in relevant environment	Engineering-scale models or prototypes are tested in a relevant environment. This represents a major step up in a technology's demonstrated readiness. Examples include testing an engineering scale prototypical system with a range of simulants.(1) Supporting information includes results from the engineering scale testing and analysis of the differences between the engineering scale, prototypical system/environment, and analysis of what the experimental results mean for the eventual operating system/environment. TRL 6 begins true engineering development of the technology as an operational system. The major difference between TRL 5 and 6 is the step up from laboratory scale to engineering scale and the determination of scaling factors that will enable design of the operating system. The prototype should be capable of performing all the functions that will be required of the operational system. The operating environment for the testing should closely represent the actual operating environment.
Technology Development	**TRL 5**	Laboratory scale, similar system validation in relevant environment	The basic technological components are integrated so that the system configuration is similar to (matches) the final application in almost all respects. Examples include testing a high-fidelity, laboratory scale system in a simulated environment with a range of simulants (1) and actual waste (2). Supporting information includes results from the laboratory scale testing, analysis of the differences between the laboratory and eventual operating system/environment, and analysis of what the experimental results mean for the eventual operating system/environment. The major difference between TRL 4 and 5 is the increase in the fidelity of the system and environment to the actual application. The system tested is almost prototypical.

Relative Level of Technology Development	Technology Readiness Level	TRL Definition	Description
Technology Development	**TRL 4**	Component and/or system validation in laboratory environment	The basic technological components are integrated to establish that the pieces will work together. This is relatively "low fidelity" compared with the eventual system. Examples include integration of ad hoc hardware in a laboratory and testing with a range of simulants and small-scale tests on actual waste (2). Supporting information includes the results of the integrated experiments and estimates of how the experimental components and experimental test results differ from the expected system performance goals. TRL 4-6 represent the bridge from scientific research to engineering. TRL 4 is the first step in determining whether the individual components will work together as a system. The laboratory system will probably be a mix of on hand equipment and a few special purpose components that may require special handling, calibration, or alignment to get them to function.
Research to Prove Feasibility	**TRL 3**	Analytical and experimental critical function and/or characteristic proof of concept	Active research and development (R&D) is initiated. This includes analytical studies and laboratory-scale studies to physically validate the analytical predictions of separate elements of the technology. Examples include components that are not yet integrated, or representative tested with simulants.(1) Supporting information includes results of laboratory tests performed to measure parameters of interest and comparison to analytical predictions for critical subsystems. At TRL 3 the work has moved beyond the paper phase to experimental work that verifies that the concept works as expected on simulants. Components of the technology are validated, but there is no attempt to integrate the components into a complete system. Modeling and simulation may be used to complement physical experiments.
	TRL 2	Technology concept and/or application formulated	Once basic principles are observed, practical applications can be invented. Applications are speculative, and there may be no proof or detailed analysis to support the assumptions. Examples are still limited to analytic studies. Supporting information includes publications or other references that outline the application being considered and that provide analysis to support the concept. The step up from TRL 1 to TRL 2 moves the ideas from pure to applied research. Most of the work is analytical or paper studies with the emphasis on understanding the science better. Experimental work is designed to corroborate the basic scientific observations made during TRL 1 work.
Basic Technology Research	**TRL 1**	Basic principles observed and reported	This is the lowest level of technology readiness. Scientific research begins to be translated into applied R&D. Examples might include paper studies of a technology's basic properties or experimental work that consists mainly of observations of the physical world. Supporting Information includes published research or other references that identify the principles that underlie the technology.

[1] Simulants should match relevant chemical and physical properties.
[2] Testing with as wide a range of actual waste as practicable and consistent with waste availability, safety, ALARA, cost and project risk is highly desirable.

Source: U.S. Department of Energy, "Technology Readiness Assessment Guide". Office of Management. 2011.

7.0 ACKNOWLEDGEMENT AND DISCLAIMER

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