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Power-to-Gas System Valuation: Final Report

June 2020

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U.S. DEPARTMENT OF ENERGY

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Summary

To provide a framework for evaluating the technical and financial benefits of a power-to-gas (P2G) system deployed in the Holyoke Gas and Electric (HG&E) system, Pacific Northwest National Laboratory modified its energy storage valuation tools to run a 1-year simulation of P2G operations. The simulation was used to evaluate the benefits of P2G for multiple grid and industrial applications over the economic life of the unit, or units, depending on the asset configuration.

A P2G system includes a number of general hardware and software elements: an electrolyzer that uses electrical energy to split water into hydrogen and oxygen; water and hydrogen purification and power conditioning; hardware and software subsystems that inject hydrogen into the gas grid network and deliver renewable gas at appropriate volumes and pressures; system enclosures; and safety control systems. System size is largely a function of the power input of the electrolyzer and it is scalable. The ITM Power Proton Exchange Membrane electrolyzer production output and power consumption can be ramped up or down with a sub-second response making it available for market operations. System size and operating levels are key variables that the model used to maximize the system economics for the HG&E case. Under the base case, we assume a basic 10 megawatt (MW) ITM Power system. This report also considers a scenario with a 5 MW P2G system. With that noted, the system is scalable in the model.

The model developed for this study allowed the research team to evaluate a broad range of scenarios with varying parameters associated with prices, technology cost and performance, and incentives. Table ES.1 defines the cases evaluated in this study and presents the economic findings with respect to each case. Total present value (PV) benefits and costs incurred over the 20-year economic life of the P2G unit and other subsystems are presented along with return on investment (ROI) ratios. An ROI ratio is calculated by dividing PV benefits by PV costs. An ROI ratio greater than 1.0 indicates a positive economic return. Note the range presented for each case. Within each case, and indeed every sub-case, there are four scenarios that include conditions with and without reservoirs and both real-time market and day-ahead market pricing. Sub-cases identified in Table ES.1 include varying assumptions around pricing, demand and policy incentives. The description in the table indicates how each case varies from the base case. More detail is provided for each case in the main body of the report. Detailed findings are presented in two appendices.

Of the 82 cases evaluated under this study, 76 yielded ROI ratios of under 1.0. Four of the cases generating ROI ratios in excess of 1.0 had lower costs because the capacity of the P2G unit was reduced to 5 MW, suggesting that the base system evaluated in this study at 10 MW was larger than optimal given the landscape of economic opportunity.

Results were most affected by demand for hydrogen as a transportation fuel. At $7/kg, the transportation sector represents the best economic opportunity for hydrogen revenue. In the absence of cavern storage, methanation is required and injection into the natural gas pipeline generates very limited revenue. With depleted natural gas reservoir storage, as explored in this study, hydrogen can bypass the methanation process, thus lowering costs. Benefits also are higher under scenarios with reservoirs because the hydrogen can be stored seasonally to take advantage of higher natural gas prices during winter months when pipeline capacity is constrained and HG&E is paying higher prices for delivered liquified natural gas. Even in scenarios with reservoirs, hydrogen for natural gas injection in the current price environment was largely a minor economic driver. With that noted, HG&E does not currently have any reservoir storage capacity.

Table ES.1. Results by Scenario Examined in this Report

Case #	Case Definition	20-Year PV Benefits ($Millions)	20-Year PV Costs ($Millions)	ROI Ratio
1	Hydrogen for transportation fuel only	5.6-5.7	21.5-22.1	0.26
2	Hydrogen for transportation fuel and natural gas injection	5.6-6.2	21.6-22.4	0.25-0.28
3	Hydrogen for transportation fuel and natural gas injection, with additional revenue from varying P2G unit electrical load to provide frequency regulation (base case)	8.5-15.7	23.2-29.0	0.37-0.54
4a	Industrial gas sold at $2/kg	10.6-16.7	25.6-30.5	0.41-0.55
4b	Industrial gas sold at $4/kg	12.3-18.5	25.7-30.7	0.48.-0.60
5a	Doubling of demand for transportation fuel	14.8-20.9	24.4-29.3	0.61-0.71
5b	Tripling of demand for transportation fuel	21.2-26.3	25.8-29.9	0.82-0.88
5c	Transportation fuel price of $4/kg	6.0-13.3	23.1-29.0	0.26-0.46
5d	Transportation fuel price of $10/kg	10.9-18.2	23.2-29.0	0.47-0.63
6a	Allow 1% hydrogen injected into natural gas grid w/o methanation	8.5-15.7	23.0-28.9	0.37-0.54
6b	Allow 2% hydrogen injected into natural gas grid w/o methanation	8.6-15.7	23.1-28.9	0.37-0.54
6c	Allow 5% hydrogen injected into natural gas grid w/o methanation	8.7-15.7	23.2-28.9	0.38-0.54
7	Assume that energy prices are zero with no emissions from electricity used to power the electrolyzer from March 19-June 20	11.8-19.2	23.6-27.0	0.50-0.71
8a	Carbon tax at $50/ton	16.3-31.3	29.4-39.9	0.56-0.78
8b	Low carbon fuel standard at $2.5/kg	10.5-17.8	23.2-29.0	0.45-0.61
9a	P2G unit paying retail prices, served by a distribution utility	11.0-13.6	25.0-27.0	0.44-0.50
9b	P2G unit paying retail prices, served by a municipal utility	11.1-13.5	24.9-26.8	0.45-0.50
10a	Case 3 with 5 MW P2G unit	7.4-10.5	13.6-16.2	0.54-0.65
10b	Case 5b with 5 MW P2G unit	20.1-21.7	16.8-18.1	1.19-1.21
10c	Case 8a with 5 MW P2G unit	11.0-18.2	16.3-21.6	0.68-0.84
10d	Case 7 with 5 MW P2G unit	9.0-12.2	13.7-15.2	0.65-0.80
11	Zero energy prices and emissions 3/19-6/20 with carbon tax and double transportation demand	26.7-40.1	28.8-36.2	0.93-1.12

Participation in the frequency regulation market improves project economics considerably by both generating revenue and improving the value proposition for injection into the natural gas grid. Under scenarios with frequency regulation, revenue associated with natural gas grid injection is much higher because participation in the frequency regulation market effectively subsidizes production costs by providing the operator a source of revenue obtained by varying production rates while following an automatic generation control signal.

While the economic returns for the system considered in this study are not sufficient in nearly all scenarios to justify system costs, the model accompanying this report will enable utilities, developers, and other interested parties in Massachusetts, to evaluate a number of future scenarios in which increased demand for hydrogen, clean energy incentives and reduced costs could lead to more positive returns. This report outlines default values for every price, cost, and policy element, but the model itself will enable the user to vary each of these parameters to evaluate scenarios with alternative operational paradigms or future economic or policy environments.

Acknowledgments

We are grateful to the Massachusetts Clean Energy Center for its financial support and leadership without which this project would not have been possible. We also are grateful to Dr. Imre Gyuk, who is the Energy Storage Program Manager in the Office of Electricity at the U.S. Department of Energy, for providing financial support and leadership on this and other related work at Pacific Northwest National Laboratory.

Acronyms and Abbreviations

AC	annualized cost
AGC	automatic generation control
ATRR	Alternative Technology Regulating Resource
bcf	billion cubic feet
BTU	British Thermal Unit
CI	capital investment
CRF	capital recovery factor
DAM	day-ahead market
DOE	Department of Energy
DRR	demand response resource
Dth	dekatherm
EIA	Energy Information Administration
FCA	Forward Capacity Auction
FCEV	fuel cell electric vehicle
FCR	fixed charge rate
HG&E	Holyoke Gas & Electric
ISO-NE	Independent Service Operator-New England
kg	kilogram
kW	kilowatt
kWh	kilowatt hour
LCFS	low carbon fuel standard
LNG	liquified natural gas
MACRS	Modified Accelerated Cost Recovery System
MW	megawatt
MWh	megawatt hour(s)
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
P2G	power-to-gas
PEM	proton exchange membrane
PNNL	Pacific Northwest National Laboratory
PV	present value
RCCP	regulation capacity clearing price
RCP	regulation clearing price
RNS	Regional Network Service
ROI	return on investment
RSCP	regulation service clearing price
RTM	real-time market
TOU	time-of-use

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1.0 Introduction

For the development and evaluation of alternative power-to-gas (P2G) control and dispatch algorithms, energy storage evaluation tools previously developed by Pacific Northwest National Laboratory (PNNL) were modified to simulate P2G operations and evaluate the services provided by an ITM Power P2G unit sited in the Holyoke Gas and Electric (HG&E) service territory within Massachusetts. The size, scope, and cost of a P2G system is such that ITM Power must demonstrate P2G system feasibility using the functional data from already-installed systems with economic modeling of a system at HG&E prior to system purchase and deployment. Therefore, this activity involved modeling rather than hardware procurement and placement.

Funded by the U.S. Department of Energy (DOE), the Bonneville Power Administration, the U.S. Department of Defense, and the State of Washington, PNNL has been advancing the functionality and sophistication of grid and storage analytics ranging from large electric system analyses that identify high-value applications for storage systems to highly detailed analyses seeking optimal placement options for grid-connected energy storage systems in a utility's service territory.

Figure 1.1 presents the project synopsis, the objectives of which were to evaluate the technical and financial benefits of P2G in the HG&E network and to develop a tool that can be used more broadly to evaluate the benefits of P2G used by other Massachusetts-based entities.

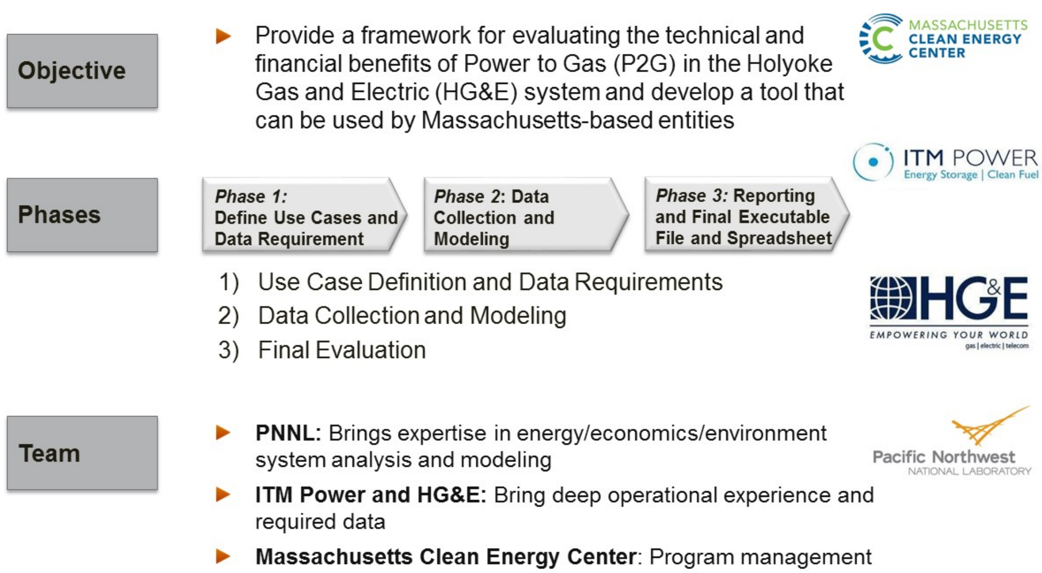


Figure 1.1. Power-to-Gas Analytics Program Synopsis

PNNL defined P2G operational scenarios to be evaluated in this project—use cases that reflect a wide range of potential market pricing, product tariff, market demand possibilities, and alternative combinations of products based on likely future pricing. The evaluated use cases used P2G operational data from ITM Power's installed systems in Europe and pricing and market data supplied by HG&E and obtained from the Independent System Operator-New England (ISO-NE). This represents the final report, and presents a detailed overview of the study methodology and economic findings for each use case evaluated in the study.

2.0 Methodology

This section provides a detailed description of the necessary methods and input information used to perform the use case analyses and, where appropriate, to provide input for the development of optimal control strategies. PNNL assisted ITM Power in the definition, development, and refinement of methods used to assess the technical and financial benefits of the use cases selected for evaluation.

P2G operations were modeled to determine the financial benefits for each use case or service offered by P2G and any accompanying systems. Bundling of services (providing multiple services over a set period) was analyzed, and improvement in the overall economics of P2G was evaluated. Because these services are effectively in competition for P2G hydrogen and energy, PNNL developed a simulation platform to define optimal control strategies. PNNL's energy storage evaluation tools have been refined to enable the assessment of P2G facilities and were used to run a 1-year simulation of P2G operations. The simulation platform was used to evaluate the benefits of P2G for multiple grid and industrial applications.

For the purposes of this study, a base case (Case 3) was established with 1 year being analyzed in detail. The mapping of cost savings, economic benefits, and operational benefits to HG&E was explored. The PNNL team evaluated alternative scenarios around hydrogen and natural gas prices, carbon regulatory regimes, and others to determine the sensitivity of the results with respect to each of these conditions. Present value (PV) benefits over the economic life of the P2G plant was compared to PV life cycle costs to determine net benefits and return on investment (ROI) ratios. An executable file with a graphical user interface was provided, along with spreadsheets for data input. The model is broadly applicable to other entities considering P2G in Massachusetts. With the data sources and parameters clearly defined, users have the ability to update the model to aid in evaluating P2G in other markets and locations. The broad application of the model dictates that certain scenarios and combinations of assets may not be directly applicable to HG&E. We include these additional elements to make the tool useful to a broader audience.

2.1 Technology Definition and System Scope

P2G supports a web of potential assets that could be used to transform electrical energy into hydrogen either for use as transportation fuel or industrial gas, or as a source of clean fuel for injection into the natural gas grid. When P2G operates independently, it also can provide wholesale grid services (e.g., frequency regulation) through load modification. When combined with fuel cells or other generation technologies, the set of use cases the system can provide expands.

The P2G system scope for this analysis includes an electrolyzer and two pathways for sale of the end-product: bulk sale in the form of transportation fuel or industrial gas, and injection into the natural gas grid. The technology components necessary for sale to transportation and industrial users include compression and modular storage tanks. For direct injection into natural gas pipelines, technology components include methanation reactor (optional) and cavern storage (optional). The tool also allows for short-term storage of hydrogen in compressed hydrogen storage tanks, which may be accessible to inject into the natural gas pipeline, and for longer term storage in underground caverns.

Figure 2.1 illustrates the pathways modeled under this program. The model contains a P2G electrolyzer that is fed from the electricity grid and connected to two end uses: 1) high-pressure (550 bar) storage tube tanks for direct sale in the transportation or industrial sectors and 2) the natural gas pipeline for direct injection. Methanation of hydrogen and seasonal bulk storage are options prior to injection into the natural gas pipelines. The model co-optimizes between the two pathways and the user can select methanation and cavern storage as optional variants.

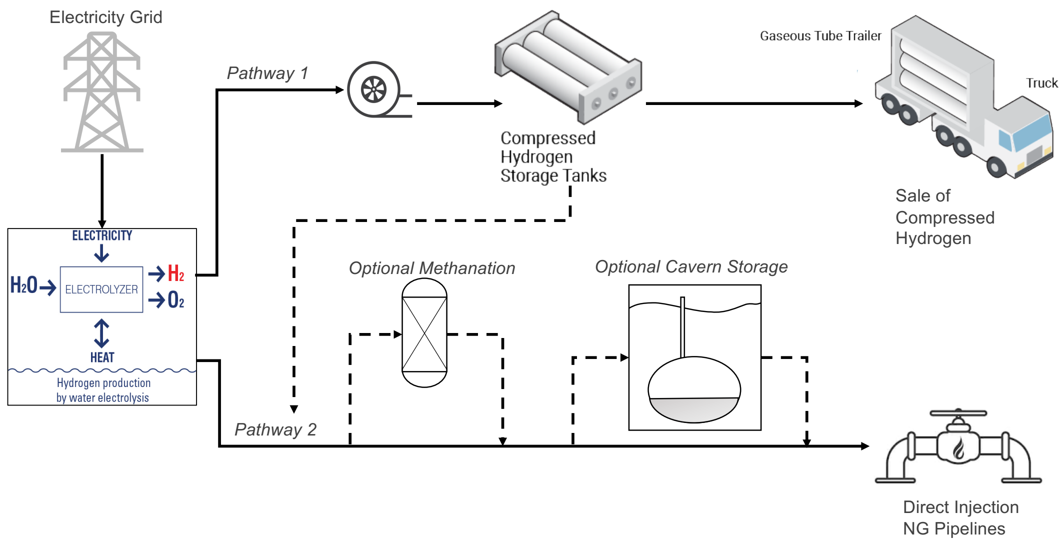


Figure 2.1. Power-to-Gas System Scope

Performance and cost characterizations of the electrolyzer, storage, and methanation are presented in Table 2.1, Table 2.2, and Table 2.3, respectively. Data presented in Table 2.1 was provided by ITM Power and DOE's Hydrogen and Fuel Cell Technologies Office. All price values are brought to $2019 using the Consumer Price Index (BLS 2019).

A P2G electrolysis system is comprised of a number of general hardware and software elements: an electrolyzer, which uses electrical energy to split water into hydrogen and oxygen; water and hydrogen purification and power conditioning; hardware and software subsystems, which inject hydrogen into the gas grid network and deliver renewable gas at appropriate volume and pressure; system enclosures; and safety control systems. System size is largely a function of the power input of the electrolyzer and it is scalable. The ITM Power Proton Exchange Membrane (PEM) electrolyzer production output and power consumption can be ramped up or down with a sub-second response. For this analysis, we assume a standard 10 megawatt (MW) ITM PEM system design under the base case, and a smaller 5 MW system under an alternative case. This peak load includes all ancillary systems associated with the P2G system. Loads associated with compression and methanation are separate from the P2G system load. This P2G system produces hydrogen pressurized to 20 bar at a rate up to 166.7 kilogram (kg) per hour. A pressure of 20 bar would exceed the limits of the HG&E natural gas distribution pipeline into which it would be injected. Thus, a regulator would be used to reduce the pressure to below 5.5 bar prior to injection. ITM Power could provide systems of larger scale. Thus, the tool enables the user to build the system up to 100 MW. Technology cost and performance characteristics of the electrolyzer are presented in Table 2.1. All costs scale linearly in our model. Where ranges are provided, the user can toggle costs up and down, while the mid-point estimate will serve as a default.

Table 2.1. Electrolyzer Technology Cost and Performance Characteristics

Element	Costs and Performance Characteristics
P2G Rated Power Capacity (MW)	10[(a)]
P2G Overnight Capital Cost ($/kilowatt [kW])	800-1,200[(a)]
P2G Fixed Operations and Maintenance (O&M) ($/kW-year)	40-60[(a)]
Hydrogen Production at Maximum Input Power (kg/24h)	4,000[(a)]
Electrolyzer Efficiency (%)	55-60[a)]
Electrolyzer Efficiency (kWh/kg)	55-61[(a)]
Electrolyzer Minimum Part-Load (%)	20 (operational) – 0.5 (idling)[(a)]
Startup Time (Time to First Production of Hydrogen)	30 sec (idling) – 300 sec (off)
Electrolyzer Economic Life (years)	20[(a)]
(a) Jones 2018.	

Production of hydrogen involves heavy water usage and drainage. Depending on the system dynamics and size, the cost for the use of water and drainage can vary significantly. The tariff rates for water use and drainage are set by the Holyoke Water Works Department and Holyoke City Works Department, respectively. For water use, the rate is $0.4709/100 gallons with a minimum of $47.09 for 0-10,000 gallons per quarter (Holyoke Water Works Department 2020). Beyond 10,000 gallons, the price is $0.4709 per 100 gallons. For drainage, the cost is $0.6650/100 gallons with no minimum (Holyoke City Works Department 2020). This results in a cost of $0.004709 per gallon for usage and $0.006650 per gallon for drainage. The P2G system uses 5.3 gallons of water and drains 2.65 gallons of water per kg of produced hydrogen (Smith 2020). Thus, the total cost for water charges is approximately $0.025 per kg of hydrogen produced and drainage is approximately $0.018 per kg of hydrogen produced.

In the first pathway in Figure 2.1, the final end-use of the hydrogen is compressed transportation fuel or industrial gas. After exiting the electrolyzer, the hydrogen is sent through a compressor into tube storage tanks. Compressors are necessary to pressurize hydrogen from 20 bar to 500 bar for short-term onsite storage prior to transport via tube trailer trucks. Pressures for modular composite storage in tube trailers range from 500 to 550 bar (7,300-8,000 psi) with size limits of roughly 720–1100 kg (DOE FCTO 2015). The default in the model was set at 1000 kg. These highly pressurized storage tubes are designed for the transport of hydrogen destined for vehicle refueling stations or industrial users. The efficiency of the entire compression unit, which encompasses the isentropic efficiency, losses, motor efficiency, and motor size, can be characterized as a function of electricity consumed per each kg of hydrogen compressed, which is 1.4 kilowatt hours (kWh)/kg (DOE FCTO 2015). The compressor is sized based on the production capacity of the P2G plant. Once the hydrogen has been compressed and injected into the modular steel storage tubes, a tube trailer either exchanges empty on-board tubes for filled ones or directly fills its payload from the compressor. In the system modeled in this analysis, the former fill technique is adopted.

The storage tanks enable the system to buffer the infrequent arrival of tube trailer trucks; demand for compressed hydrogen as a transportation fuel in New England is small compared with the proposed production of this system (see Section 2.2.3). Storage equivalent of 2 to 5 days of end-use demand will be necessary to maintain a rolling stock (Jones 2019). This storage capacity also can be scaled to cover demand for industrial gas. The total number of tanks is a function of the customer's demand and the number of customers. As modeled, it is the equivalent to one tank connected to the P2G unit plus one customer-sited tank for each

1000 kg of half-weekly demand reserves for each customer. For HG&E, the default number of tanks will be four; two connected to the P2G unit, and two at a single customer site, sized for the demand of hydrogen. In scenarios with industrial gas sales, two additional units are required. Technology cost and performance characteristics for hydrogen compression and storage are given in Table 2.2. As the number of customers and weekly demand for transportation fuel and industrial gas grows, the model will automatically adjust to modify the number of required storage tanks.

Table 2.2. Hydrogen Compression and Storage Technology Cost and Performance Characteristics

Element	Costs and Performance Characteristics
Compressor CAPEX, 100 kg/h ($) (2 Compressors are Required at Stated Cost for 10 MW P2G system)	100,000[a]
Compressor Specific Energy (kWh/kg)	1.4[a]
Compressor Annual OPEX (% of CAPEX)	4[a]
Compressor Losses (% of Hydrogen)	0.5[a]
Gaseous Hydrogen Tube Storage (500 bar) CAPEX ($/kg)	680 [a]
Gaseous Hydrogen Tube Storage Capacity (kg)	720-1,100[a]

(a) DOE FCTO 2015.

In the second pathway shown in Figure 2.1, the final end-use of the hydrogen is uncompressed fuel into the natural gas pipeline. The pressure of hydrogen exiting the electrolyzer is 20 bar (300 psi), which is higher than the acceptable range for natural gas distribution lines. This is addressed through the use of a regulator that will reduce the pressure of the hydrogen exiting the electrolyzer to below 5.5 bar prior to injection in the HG&E natural gas distribution line. Natural gas transmission lines operate between 35 and 80 bar. Leakage of hydrogen is not a concern for distribution lines due to the lower pressure; injection into the distribution lines is recommended (Ogden et al. 2018). For HG&E, injection into the natural gas pipeline system would occur at the distribution level.

There are limitations on the amount of hydrogen that can be injected into the natural gas pipelines. Hydrogen may be admixed directly into the natural gas pipelines assuming two conditions are met: the pressure exiting the electrolyzer is equivalent to that of the distribution pipelines and admixture rates do not exceed allowable levels. While some countries, such as the United Kingdom, have well-defined regulations for hydrogen injection and admixing (0.1% by volume for the UK today), hydrogen injection projects in other countries typically follow national biomethane injection protocols (Tractabel 2017). There are several European nations with higher injection rates, reaching as high as 12% as a percent of volume in Holland. At HG&E, at its peak the system delivers 950 dekatherms (Dth)/hour. At a minimum, the system delivers 20 Dth/hour. The model has been designed to use monthly minimum delivery rates, as specified by HG&E. The model will enable the user to change these monthly delivery rates.

Two options in the system are available to the user along the second pathway: methanation of hydrogen and underground cavern storage. Cavern storage and hydrogen methanation may be selected independently or together.

Methanation of hydrogen would alleviate volumetric admixture constraints on pipeline injection. The model determines the rate of energy injection (e.g., Dth/hour). The user is allowed to define the hourly delivery rate of the natural gas system and the hydrogen volumetric admixing percentage allowable for the plant. If the production of the P2G electrolyzer exceeds the hydrogen admixing volumetric limit, the model will automatically require redirection of the marginal hydrogen production. The hydrogen would be redirected to either methanation and then injection of methane, cavern storage, or compressed onsite storage. The methanation process has the option of either a biologic or catalytic reactor, with the catalytic reactor serving as the base case, and requires carbon dioxide as a feedstock. The model allows the user to specify a cost for the purchase of carbon dioxide for methane production; however, a default value of 2.4 cents per kilogram is used (IHS 2020). The methanation system efficiency is constrained by the Sabatier reaction, where four molecules of hydrogen and one of carbon dioxide produce one molecule of methane and two of water. With 100% conversion of gas, the energy efficiency is 77.85%; for every 1 kg of hydrogen, 5.5 kg of carbon dioxide are needed to generate 2 kg of methane. The power requirement of biologic methanation is 220 – 250 kW for a maximum intake of 190 kg/h. Additional conversions, unit costs, and technology characteristics are given in Table 2.3.

Underground cavern storage affords the user large scale seasonal storage to hedge against natural gas price spikes at the tail-end of the winter season when supply has waned or at any time of peak demand in pipeline capacity constrained regions such as New England, including the HG&E service territory. Storage capacity was limited by the size of an average depleted natural gas reservoir. The working underground storage of natural gas in an average depleted field is roughly 11.5 billion cubic feet (bcf) (Fang, Ciatto, and Brock 2016). This type of cavern can deliver a maximum of 0.23 bcf per day. Assuming the gas is pressurized to 200-500 bar within the cavern, this corresponds to 575 million kg annual average, and a maximum daily withdrawal rate of 115 million kg (Sheffield, Martin, and Folkson 2014). In general, caverns created from natural gas reservoirs require slower injection and withdrawal rates compared with salt caverns. The majority of caverns in the U.S. East Region are depleted natural gas or oil fields (Fang, Ciatto, and Brock 2016). The availability of gas from the U.S. East Region fluctuates from over 750 bcf prior to winter to less than 250 bcf toward the end of winter (EIA 2019a). The user is allowed to modify the size of the storage cavern.

Hydrogen that is injected into the cavern will mix with the existing natural gas. The ratio of injected hydrogen to existing base natural gas in the cavern is so small that the resulting mixture is effectively natural gas. Methanation prior to cavern injection is thus not necessary; however, the user will retain the option to include this step. As the gas is injected into the cavern, the pressure of the gas will increase due to the existence of base gas. Thus, all the injected gas is considered working gas. This pressurization via injection allows for extraction at a later time for injection into the natural gas pipelines. Although natural gas caverns are typically cycled (filled and withdrawn) one to two times per year, the underground storage in this analysis is treated as though it may be cycled at liberty (Reddi et al. 2016). Costs for underground storage are considered negligible, as the system will take advantage of existing underground caverns, though the model will enable the user to specify a storage cost per bcf.

Table 2.3. Methanation Technology Cost and Performance Characteristics

Element	Costs and Performance Characteristics
Methanation Nominal Power (kW)[i]	220[a]-250[b]
Biologic Methanation Reactor CAPEX ($/kW)[j]	330-780[c]
Catalytic Methanation Reactor CAPEX ($/kW)	450-560[c]
Fixed Methanation OPEX (% of CAPEX)	5[d]
Variable Methanation OPEX ($/h; Cold Standby/Hot Standby/Operation)	0.55/34.40/6.90[d]
Methanation Electricity Consumption (kW; Cold Standby/Hot Standby/Operation)	20/250/250[d]
Methanation Gas Conversion (therms$_{CH4}$ out/kg$_{H2}$ in)	1.05[e]
Time from Cold Standby to Hot Standby (Biological Methanation, h)	1[f]
CO_2 necessary for Methanation (kg CO_2/kg hydrogen)	5.5
Cost of CO_2 ($/kg)	0.024[h]
Minimum Natural Gas Distribution Line Energy Throughput (Dth/hour)	20[g]
Methanation Reactor Economic Life (years)	20[d]

(a) Electrochaea (2018)
(b) Thema, et al. (2019)
(c) Thema, Bauer, and Sterner 2019
(d) Gorre et al (2019)
(e) Assumes 100% conversion of gas; 1 MJ hydrogen yields 0.7785 MJ CH_4 based on higher heating value
(f) Gorre (2019)
(g) Beauregard (2019)
(h) IHS (2020)
(i) The methanation system outlined here is scaled to the size of the electrolyzer; the power requirement of the methanation system is 25 kW for each MW electrolyzer (Gorre, et al 2019). The model automatically adjusts energy consumption and production to account for larger P2G systems.
(j) The methanation system outlined here is scaled to process 190kg/h. The model automatically adjusts energy consumption and production to account for larger P2G systems.
(k) Cost per kW of installed electrolyzer.

The values in Table 2.1, Table 2.2, and Table 2.3 serve as model defaults. The user can change these values to customize the analysis to meet their needs. This feature also will ensure that the model remains useful as efficiencies are realized and costs evolve over time.

2.2 Definition of Operational Scenario and Use Cases

Working with HG&E, PNNL has defined operational scenarios for simulating the economic operation of the P2G system defined by ITM Power for potential deployment in the HG&E system. The operational scenarios evaluated in this project included use cases that reflect a wide range of potential market pricing, product tariff, and market demand possibilities. These use cases are based on P2G operational data from ITM Power's installed systems in Europe and pricing, policy, and market data supplied by HG&E or obtained directly by PNNL through ISO-NE.

The operational scenarios evaluated included the following services: load reduction / demand response, frequency regulation, capacity, regional network service (RNS) charges, renewable gas delivered by the natural gas grid, transportation fuels, industrial gas, and clean energy incentives. It is important to note that capacity and RNS fees represent costs that the model attempts to avoid by minimizing load during peak system-wide load events. Clean energy incentives, including carbon taxes and hydrogen or low carbon fuel standard (LCFS) credits, could result in enhanced value to P2G systems and are, therefore, also evaluated.

In addition to the operational scenarios outlined above, the model developed under this project allows the user to evaluate results across multiple scenarios differentiated by several additional parameters:

- *Prices* – Market prices, capital costs, production costs, and prices for natural gas or hydrogen
- *Specifications/configuration* – System scale and asset configurations
- *Incentives* – Clean energy grant programs, carbon taxes, tax incentives, hydrogen or LCFS credits.

Each of these parameters serves as inputs into the model, with results demonstrating the sensitivity of the results to assumptions governing each parameter (Figure 2.2).

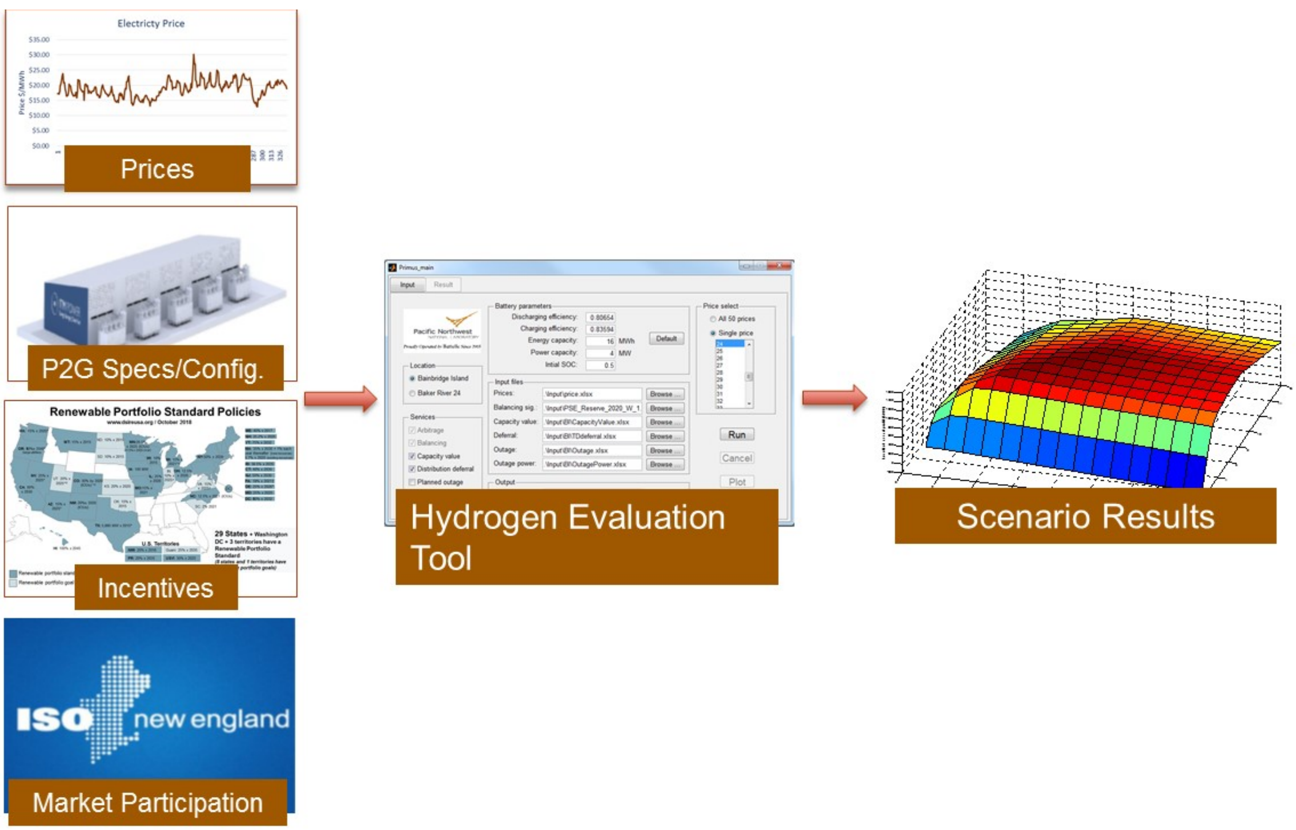


Figure 2.2. Varying Key Parameters to Evaluate Multiple Scenarios

In this section, we define four operational approaches for deploying P2G in Massachusetts. Each approach involves different energy costs and market opportunities. There are four options explored in the model:

1. *Operation by a municipal utility*. As an HG&E asset, the P2G system would be subject to energy related costs, including energy purchases, capacity, and RNS charges. One set of use cases relies on the P2G system being operated in a manner as to minimize these costs. Energy prices are based on day-ahead market (DAM) or real-time market (RTM) ISO-NE prices. The model also enables the operator to provide frequency regulation services as an alternative technology regulation resource (ATRR)
2. *Operation as a transmission connected asset*. P2G operating in the transmission system would face spot-market ISO-NE prices, RNS, and capacity charges. In terms of market revenue, the model enables the user to operate the P2G plant as an ATRR.
3. *Operation in the distribution system served by a distribution utility*. In this scenario, the operator would face demand charge and time-of-use (TOU) rates. It could enroll in utility-sponsored demand response programs and ISO-NE frequency regulation markets.
4. *Operation in the distribution system served by a municipal utility*. Under this structure, the operator would pay for energy based on the tariff set by the municipal utility. These rates typically do not involve TOU rates, though they do in limited circumstances. The model enables the user to participate in regulation markets but no demand response opportunities are offered.

Each utility will have different distribution charges, and potentially tariff designs, affecting costs. These differences are discussed in the next section of this report.

2.2.1 P2G Operation as a Grid Asset

As a 10 MW asset, the P2G system will have several options for incurring energy prices and operating as a grid asset, as outlined in the previous section. This section defines operations in a more detailed manner, as differentiated based on each of the aforementioned four operating scenarios.

2.2.1.1 Operation by a Municipal Utility

If operated by a municipal utility, like HG&E, the operator would pay for energy based on either DAM or RTM prices in the ISO-NE market area. In addition, the operator would pay capacity and RNS charges.

Energy Prices

Hourly wholesale market data has been obtained for Load Zone Location ID 4007 WCMASS for the May 2011-December 2018 period. Hourly RTM prices for the October 2018 period are presented in Figure 2.3. As shown, prices fluctuated between $7.21 and $366.72 per megawatt hour (MWh) during this time period. If HG&E were able to accurately predict day-ahead production schedules, it could minimize costs by adding P2G load into its load bid into the DAM. These prices are included as costs in the production of hydrogen by the P2G system, and the user is given the option of assuming DAM or RTM prices. These values serve as model defaults but can be modified by the user. There are hours when HG&E is a net producer and while this excess energy could effectively be used to support hydrogen production, there would be an opportunity cost equal to the hourly ISO-NE price as it could have otherwise been sold in the market. Thus, ISO-NE energy prices always serve as the basis of energy costs at all times for the municipal utility. Note that if the model user wishes to explore a scenario where the source of the energy is renewable-generated and would otherwise be curtailed, the user can simply enter $0 for each hour when energy costs are eliminated. We explore a scenario in this study where hydro production is producing excess supply and would otherwise be curtailed. In that scenario, energy prices and emissions during the spring are set to zero.

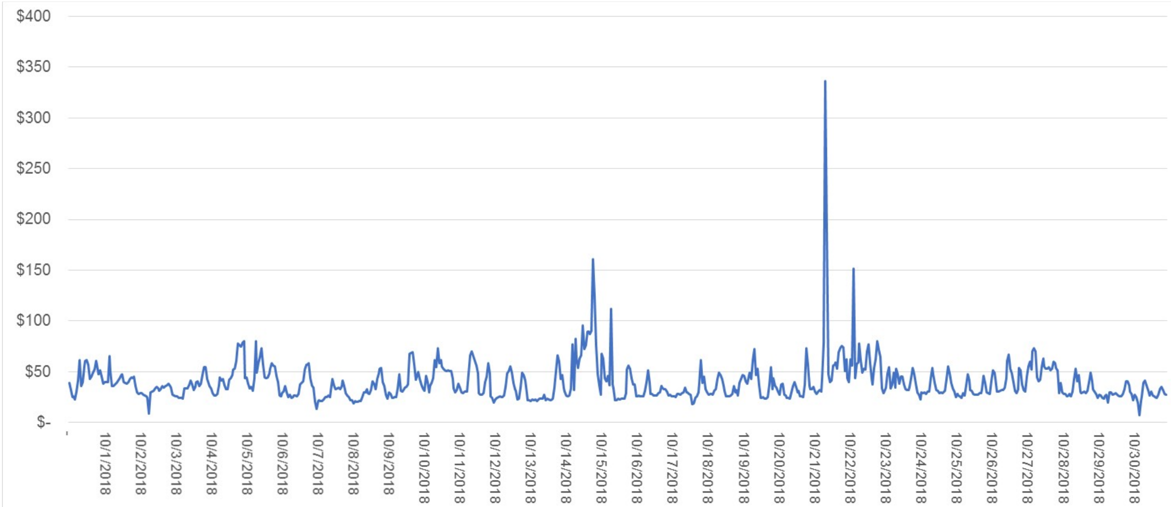


Figure 2.3. Energy Prices (per MWh) for Load Zone Location ID 4007 WCMASS in October 2018

Capacity and Regional Network Service Charges

As with the purchase of energy for the P2G system, HG&E would be subject to additional ISO-NE Capacity and RNS Charges.

A forward capacity market has been implemented by ISO-NE. Those market charges are allocated to load serving entities, including HG&E, based on the following equation:

$$\text{Capacity Payment} = \text{Capacity Supply Obligation} \times \text{Net Regional Clearing Price}$$

The Net Regional Clearing Price is calculated for each load zone. The Forward Capacity Auction has been cleared through 2023–2024 at varying rates, dipping to $2.00/kW-month. The current capacity charge is $7.03/kW-month. The capacity supply obligation is based on the peak contribution value for the load area, that is the load on the peak hour, each year, as identified by ISO-NE. To minimize the cost associated with this charge for the HG&E system, the P2G system must minimize energy use during the annual ISO-NE system-wide peak. The peak load hour for the year in 2018, for capacity purposes, occurred on August 29 from 4–5pm. The model uses this hour to establish the basis of capacity costs.

The Schedule 9 RNS is a monthly charge that represents a payment for transmission system use, that is the use of pool transmission facilities to transmit electricity within the New England Balancing Area. The monthly charge is based on the pool RNS rate and the monthly network load for a customer with a monthly regional network load (i.e. HG&E). The current Schedule 9 RNS rate is $9.33/kW-month. In addition, the RNS monthly charge also includes a charge for Open Access Transmission Tariff (OATT) Schedule 1 service, which includes transmission operator scheduling, system control, and dispatch costs. Each load customer's monthly regional network load is multiplied by the Schedule 1 OATT rate to determine this monthly charge.[1] The Schedule 1 OATT is currently $0.13 per kW-month. The P2G unit operates so as to minimize these RNS charges.

[1] Schedule 1 and Schedule 9 of the ISO-NE OATT.

Capacity values through 2022-23 and the 2018 RNS Schedule 9 value are presented in Table 2.4. Forecast values for both capacity and RNS charges have been obtained from HG&E through May 2035, though these values have been identified as proprietary and are not presented in this report. Note that for this study, capacity and transmission (RNS) costs would not generate positive revenue. Rather, they would be minimized or avoided.

Table 2.4. Capacity and RNS Costs

Start	End	Capacity ($/kW-month)	RNS ($/kW-month)
June-2018	May-2019	9.55	9.17
June-2019	May-2020	7.03	9.33
June-2020	May-2021	5.30	
June-2021	May-2022	4.63	
June-2022	May-2023	3.80	
June-2023	May-2024	2.00	

These charges apply regardless of the type of utility territory (i.e., municipal- or investor-owned distribution utility) in which the P2G asset may be placed. The charge incurred, assuming all else being equal, by the P2G system will be identical, but the relative magnitude of the impact of the P2G system to the overall rate for each network load customer will vary depending on the total load.

Table 2.5 presents the hours that defined the peak load for each month in 2018 for RNS purposes. The P2G system would benefit from curtailing load in these hours. These hours are used as defaults in the model but could be altered by the user.

Table 2.5. Peak Load Time and Date to Determine RNS Payment for 2018

Month	Peak Day Date	Peak Hour	Real-Time LMP ($/MWh)	Peak Demand (MW)
1	5	18	398.71	4,059
2	7	18	64.90	3,547
3	7	18	34.88	3,334
4	16	12	244.60	3,101
5	3	15	49.70	3,518
6	18	18	39.26	4,373
7	3	17	56.03	5,016
8	29	17	142.19	5,317
9	6	16	96.43	5,104
10	10	17	69.57	3,619
11	15	18	106.75	3,397
12	18	18	53.62	3,549

Frequency Regulation[2]

The electric power system must maintain a near real-time balance between generation and load. Balancing generation and load instantaneously and continuously is difficult because loads and generators are constantly fluctuating. Minute-to-minute load variability results from the random turning on and off of millions of individual loads. The services needed to meet such a balancing requirement are referred to as “ancillary services,” which are necessary to support the basic services of generating capacity, energy supply, and power delivery.

Regulation services are required to continuously balance generation and load under normal conditions. Regulation is the use of online generation, storage, or load that is equipped with automatic generation control (AGC) and that can change output quickly to track the moment-to-moment fluctuations in customer loads and to correct for the unintended fluctuations in generation. Regulation helps to maintain system frequency, manage differences between actual and scheduled power flows between control areas, and match generation to load within the control area. ISO-NE has a four-second AGC signal, that is AGC set points for movement are set every four seconds.

The P2G system can register as an ATRR and participate in the frequency regulation market, receiving an energy neutral AGC signal. To participate, it will have to submit a regulation capacity offer on a daily basis and clear in the regulation market.

Within ISO-NE, frequency regulation payments are determined based on regulation capacity clearing prices, the service or mileage payment of the fluctuating resource, and the regulation service performance score. A 10 MW rapid response electrolyzer can provide up to 4 MW of regulation up and 4 MW of regulation down service, using 6 MW as its base operating point. The 8 MW range covered by 4 MW of regulation up/down service is based on the operating range of the ITM Power system using a minimum operational level at 2 MW of load and a maximum at 10 MW. The ability of the ITM Power system to provide this service has been demonstrated in Europe.

Regulation prices were obtained from the ISO-NE market database for the time period 2016-2018. Regulation prices represent system-wide regulation pool prices. The amount of regulation services in each hour is limited by the capacity of the P2G system. Such constraints have been modeled in the optimal scheduling process. When regulation services are being called, the P2G system needs to modify its energy consumption in order to follow the AGC signal.

Two datasets pertaining to the regulation market were retrieved from the ISO-NE website:

- *Energy Neutral AGC Dispatch Data*. This dataset contains simulations of four-second AGC setpoints. The AGC setpoint data is based on some representative conditions such as system conditions, resource characteristics, and AGC dispatch methodologies, which are essential to normal AGC dispatch.
- *Hourly Regulation Clearing Prices (RCP)*. This dataset contains final hourly RCPs from 30 November 2010 up to 6 February. 2019. However, the regulation clearing price starting from March 31, 2015 is decomposed into the regulation service clearing price (RSCP) and regulation capacity clearing price (RCCP). RCSP is the price of the highest regulation service offer provided among the resources in the specific interval and RCCP is the price

[2] *See* ISO-NE Market Rule 1, Section 14 (Section III of the ISO New England Inc. Transmission, Markets, and Services Tariff).

that warrants recovery of the energy opportunity costs, regulation capacity costs, and resource-specific incremental cost savings. Note that the RCCP is based on the capacity of the unit's load bid into the market while the RCSP is based on the mileage of the fluctuations of load. All these figures are in $/MW units.

The final decomposed hourly RCPs are further broken down into five-minute intervals starting November 30, 2017. To compile the data and keep it consistent, the average of the 5-minute intervals was obtained to maintain a database of hourly RCPs.

The hourly RCP has been increasing both in terms of magnitude and standard deviation from 2010 to 2019. Table 2.6 summarizes the RSCP and RCP in the dataset. Note that while the maximum bids are capped for the RSCP and RCCP at $10/MWh and $100/MWh, respectively, prices have climbed as high as $2,331.55 per MWh due to the opportunity cost component of the market clearing price. These high prices reflect price spikes in the RTM that drive up the value of the next best alternative use of the market asset.

Table 2.6. Summary Statistics of the Regulation Clearing Price Data

Year	RSCP ($/MWh)	RCCP ($/MWh)
Min	0	0
Median	0.15	17.64
Max	10	2,331.55
Mean	0.34	27.86

2.2.1.2 Operation as a Transmission Connected Asset

When operating as a transmission connected asset, the operator would participate directly in ISO-NE markets and would therefore face spot-market ISO-NE energy prices. For modeling purposes, we use an average hourly RTM price. The asset would be subject to RNS and capacity costs as outlined in the previous section. The system also could operate as an ATRR and provide frequency regulation services. This scenario is effectively the same structurally as the previous scenario.

2.2.1.3 Operation in the Distribution System, Served by a Distribution Utility

A third-party owned P2G system connected directly to a distribution system will incur energy charges, which may be a flat rate-based system or TOU-based system. The rates for each provider can be accessed on Massachusetts.gov at www.mass.gov/service-details/electric-rates-and-tariffs (State of Massachusetts 2019). The rates for each of the distribution utilities in Massachusetts have been built into the model.

A third-party P2G system also would pay distribution charges in addition to any energy charges. These charges would, of course, apply to any load interconnected to a distribution system. For the purposes of this discussion, National Grid is used as the example of the utility to which a third-party P2G system would be connected, and the system would be classified under National Grid's General Service TOU G-3 Rate, which includes the following individual charges:[3]

[3] Massachusetts Electric Company. General Service Time-of-Use G-3 Rate. Tariff Provision MDPU No. 1428.

- Customer charge
- Distribution demand charge
- Distribution charge (may be broken into peak and off-peak charges and includes several adjustment and recovery factors)
- Transmission charge
- Transition energy charge
- Energy efficiency charge
- Renewables charge
- Distribution solar charge.

These charges would vary by utility, but a P2G system would generally fall under the largest rate class (e.g., General Service TOU Demand) in any utility system. In this situation, the third-party would be responsible for capacity and RNS charges as identified above, but instead pay for these services to the distribution utility through the distribution rates (e.g., transmission charge component). Once again, these rate structures have been built into the model.

Grid benefit streams when operated under this category are outlined below.

Utility Program Demand Response Participation

A third-party P2G system could participate in the Connected Solutions Program of the Massachusetts' Program Administrators (i.e., investor-owned utilities: Eversource, National Grid, and Unitil), which compensates commercial and industrial customers to curtail their energy when the ISO-NE system is forecasted to be at its peak. A participating P2G system would be compensated for the amount of energy curtailed on a pay-for-performance basis.[4]

The program offers three options to participate:

1. *Targeted Dispatch* to reduce load at the peak hour of the year (two to eight dispatch events per summer).
2. *Daily Dispatch* to reduce load at the peak hour of the year and during daily peaks in July and August (30 to 60 dispatch events per summer).
3. *Winter Dispatch* to reduce load during five peak hours of the winter.

Depending on the program administrator, the rules and incentives vary; however, they can range from $35/kW-summer to $200/kW-summer depending on the type of dispatch and therefore, associated number of events. The P2G system will be judged to reduce its consumption relative to a baseline calculated by the applicable program administrator.

[4] *See* https://www.nationalgridus.com/media/pdfs/bus-ways-to-save/connectedsolutions-ciprogrammaterials.pdf.

Demand Response Resource Baseline Calculation[5]

The demand response baseline is calculated differently for three different sets of days: weekdays, Saturdays, and holidays/Sundays. The baseline load for any day is constructed of 5-minute intervals. The calculation of each type of day is described below:

- *Weekdays*: Each 5-minute baseline interval of a weekday is based on the average of all the identical five-minute intervals from the previous 10 weekdays. For example, 10:00 am to 10:05 am baseline for a Wednesday is based on the average load from 10:00 am to 10:05 am across the 10 weekdays prior. This baseline is continuously updated for each 5-minute interval for each day using the preceding 10 appropriate days. Days on which the demand response resource (DRR) is dispatched for load reduction do not count toward the average the next day and are merely skipped over in the 10-day period.
- *Saturdays and Sundays/Holidays*: For Saturdays and Sundays/holidays, the average is based on the five preceding days of that type. For example, 10:00 am to 10:05 am baseline on Saturday is based on the average 10:00 am to 10:05 am load from the previous five Saturdays. Sundays and holidays are treated interchangeably, and the five historical days of both types are used in the average calculation for either. For example, if Monday is a holiday, the Sunday preceding it would be incorporated into the total average calculation.

ISO-NE calculates a baseline adjustment 15 minutes prior to dispatch as the difference between load and the unadjusted baseline (Figure 2.4). This adjustment is intended to capture differences in predicted load due to factors such as weather or DRR operational variations. The adjustment is added to the baseline for all intervals within the dispatch timeframe. The calculation for this adjusted baseline is based on the average load (MW) difference between the metered demand in real-time and the baseline during the three most recently completed 5-minute intervals prior to the notification window for a dispatch event (i.e., 30 minutes before an event) (Lehman 2019).

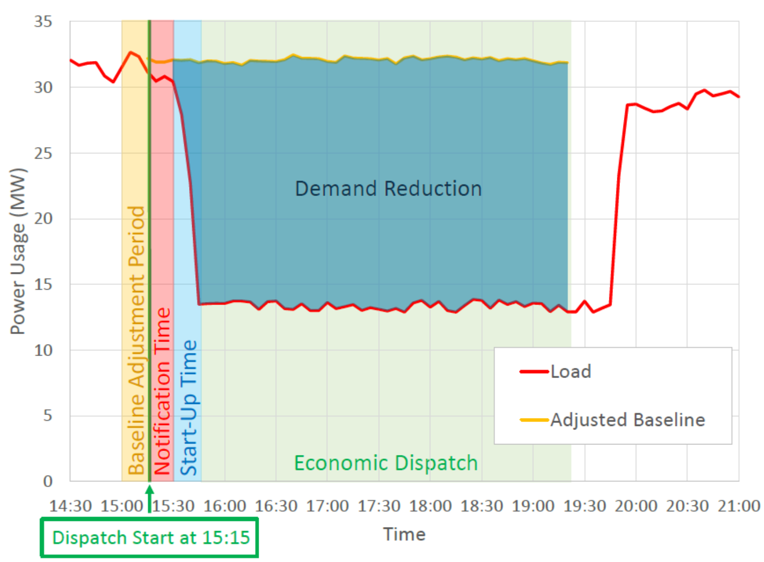


Figure 2.4. DRR Dispatch in the Energy Market

[5] *See* ISO-NE Market Rule 1, Section 8 (Section III of the ISO New England Inc. Transmission, Markets, and Services Tariff).

In addition to the demand response programs, the P2G asset also may pursue regulation revenue as an ATRR.

2.2.1.4 Operation in the Distribution System, Served by a Municipal Utility

Municipal utility structures typically involve flat rate-based systems, though some offer optional TOU and tiered structures. For example, Ipswich Municipal Light offers tiered demand and electricity charges under the Power Rate C Schedule, with rates for electricity beginning at 5.95 cents per kWh for the first 1,000 kWh of consumption each month and falling to 3.11 cents per kWh for all over 100,000 kWh per month. The model enables the user to build up municipal tariff structures, including tiered demand charges, tiered energy charge rates, and load. Aside from cost minimization, the P2G asset also may pursue revenue opportunities as an ATRR through the ISO-NE markets.

2.2.2 Hydrogen Gas Injected into the Natural Gas Grid

Hydrogen can be injected into the natural gas grid as a clean fuel, reducing greenhouse gas emissions from natural gas-fired systems served by HG&E. Hydrogen limits for injection into the natural gas grid vary by country, reaching as high as 12% by volume in Holland. In the United States, the limit is less than one percent (Jones 2017), and in many places, including Massachusetts, methanation is required to inject any hydrogen at all into natural gas pipelines.

The ITM Power P2G system requires 55-61 kWh of energy to generate 1 kg of hydrogen. One kg of hydrogen has an energy content of 0.1346 million British thermal units (BTU). Pure methane has 0.0526 MMBTUs. Prices for delivered natural gas in the HG&E system (TPG Zone 6) ranged from $3.10 to $5.20 per MMBTU in 2018. Forecast prices have been provided by HG&E through 2023.

The P2G case is stronger in New England during winter months due to natural gas pipeline capacity constraints. With no plans to expand gas pipeline capacity in the region, these constraints could continue into the future. The marginal price of natural gas during winter months can be much higher than the aforementioned base fuel prices. HG&E has fixed transportation contracts for gas up to 11,800 Dth/day, yet in winter the HG&E peak has reached as high as 19,000 Dth. Liquefied natural gas (LNG) fixed transportation, trucking, and fuel costs are significantly higher pricing than the natural gas delivered over pipeline over the winter period.

During the winter months HG&E typically executes two separate LNG contracts in the fall with fixed capacity costs and charges for trucking and fuel as delivered to meet the demand for natural gas during winter months. HG&E has shared LNG prices and daily delivered volumes during the 2018/2019 winter season. Prices ranged from $6.21 per Dth to $8.60 per Dth, or roughly twice what is paid for pipeline delivered natural gas. For this case, PNNL will run a scenario where the P2G system either uses its own storage capacity or it can take advantage of natural gas reservoirs to perform a form of natural gas arbitrage. In so doing, it will take advantage of low cost electricity prices during off-peak periods to avoid peak natural gas prices. It is important to note that HG&E does not presently possess the reservoirs necessary to take advantage of this opportunity.

2.2.3 Hydrogen as a Transportation Fuel or Industrial Gas

The market for hydrogen as a transportation fuel, while showing great promise for reducing vehicle emissions, is at a nascent stage of development in Massachusetts. A recent report completed by the Northeast Electrochemical Energy Storage Cluster evaluated the technical and economic potential for hydrogen in Massachusetts (Northeast Electrochemical Energy Storage Cluster 2018). It recommended deployment of 250 MW of fuel cell electric generation, 907 fuel cell electric vehicles (FCEV), and seven to nine hydrogen refueling stations to support FCEV deployment.

The price of hydrogen to end users in California is approximately $15 per kg (Eichman 2016). The production process can account for roughly 33 to 60% of total costs of delivering hydrogen to FCEVs, with other costs tied to transport and fueling station costs (Ramsden 2008, Fletcher 2006). Thus, the base prices for produced hydrogen included in this study range from $4 to $10 per kg, with a default of $7 per kg used in the model. The model allows the user to shift the price between $4 and $10 per kg.

Existing demand for hydrogen in and near Massachusetts to serve FCEVs is quite low at roughly 130 kg hydrogen per day (Dillich 2014). Currently, retail hydrogen fuel stations are not commercially open in Massachussets. For this reason, the demand for hydrogen from the system modeled herein via tube trailers is uncertain and, therefore, can be established by the user. At this stage in the FCEV hydrogen market on the East Coast, there is very little demand for the product; however, demand for hydrogen from FCEV users is projected to grow 4.65% annually in Massachusetts (Northeast Electrochemical Energy Storage Cluster 2018). Demand is growing much more aggressively in California. Should the electrolyzer be sited in a different market, such as California, demand would be much higher (Praxair 2019).

In this study, we explore various levels of demand to judge the sensitivity of P2G profitability with respect to low or high levels of demand for hydrogen as a transportation fuel. The monthly variability in demand for hydrogen is modeled after the monthly average daily demand for gasoline in Massachusetts (EIA 2019b). The median and inter quartile range of the monthly average daily demand is scaled to the current demand for hydrogen in Massachusetts of 130 kg per day, as shown in Figure 2.5. Variability in monthly average daily demand comes from a random draw from this distribution. The user is able to change the annual average daily demand for hydrogen from its initial set point of 130 kg. An alternative scenario that includes a doubling and tripling of demand for hydrogen as a transportation fuel also is considered.

With respect to storage, the model allows the user to define the number of customers purchasing transportation or industrial fuels. For each customer, the model reserves one tank and enough storage at the production site to cover 2-5 days of storage for the entire customer base. The model uses the mid-point of 3.5 days as the default. The number of customers will be defined for transportation and industrial uses. Under the base case, we assume there are two transportation customers and no industrial customers.

Industrial gases are offered at lower prices points, typically below $5/kg. Based on a review of published prices and those presented in relevant literature, the model establishes a price range for industrial gases at $2–$4 per kg, with $2 per kg used as the default (Glenk 2019).

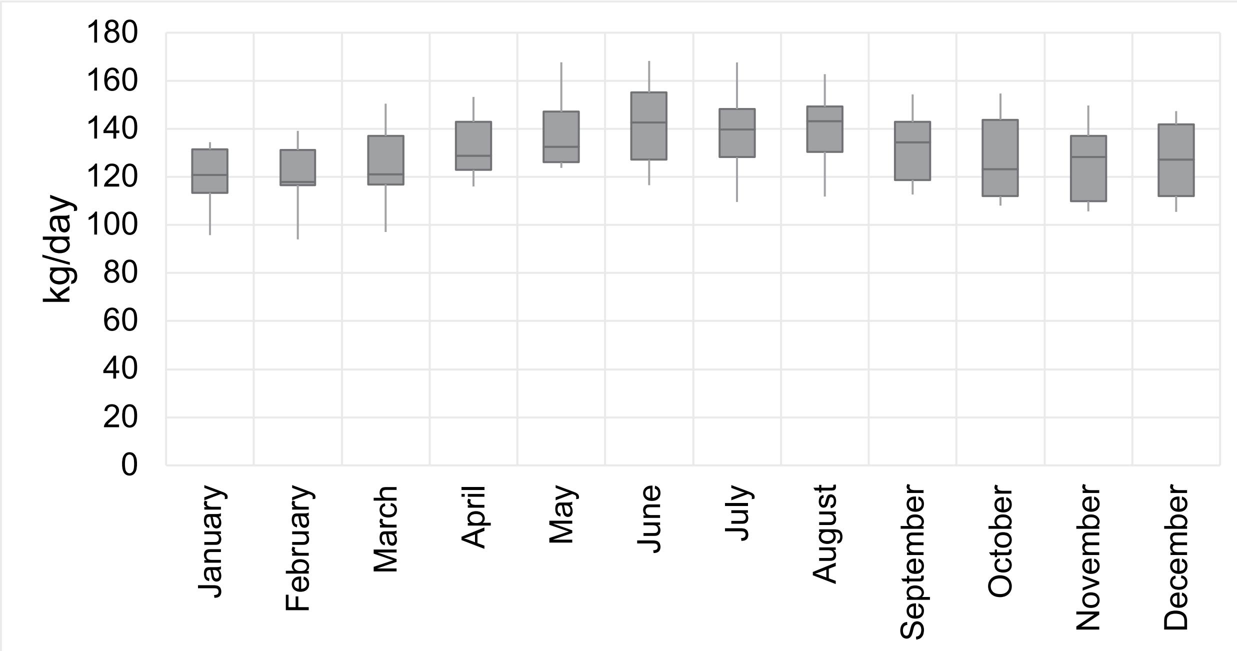


Figure 2.5. Anticipated Daily Hydrogen Sales in Massachusetts, Modeled from Monthly Average Daily Gasoline Demand

2.2.4 Clean Energy Incentives

The model enables the user to consider a number of clean energy incentives, as outlined in Table 2.7. While the user is allowed to define each of these values, a range of potential values for hydrogen or LCFS credits and carbon taxes are provided as defaults. These values are defined in Table 2.7 for this analysis. The LCFS credit range was established using rates presented by Eichman and Flores-Espino (2016). Carbon taxes are expanding around the world as countries move to implement the provisions of the Paris Accord on Climate Change.

As of 2018, 51 nations have implemented carbon pricing initiatives or are scheduled for implementation. Carbon tax rates around the world range from below $1 per ton CO_2e in Mexico, Poland, and Ukraine to as high as $139 per ton CO_2e in Sweden (World Bank Group 2018). Grant receipts, federal investment tax credits, and accelerated depreciation result in system cost reductions accounted for in the ROI calculations. With accelerated depreciation, the model uses a 5-year Modified Accelerated Cost Recovery System (MACRS) half-year convention to further discount the capital costs of the assets. See Section 2.3 for an overview of how the model treats costs.

Table 2.7. Clean Energy Incentives

Incentive	Description
Business Energy Investment Tax Credit and Accelerated Depreciation	30% Federal Investment Tax Credit and 5-year Accelerated Depreciation Schedule
Hydrogen or LCFS Credits	Credits translated into $1-$5/kg (default at $2.50/kg) based on $125/kg-$200/kg LCFS Credits
Carbon Tax	$20-$100 per ton, we use $50 in model as default
Clean Energy Grant Funding	Grant funding support through Massachusetts-based clean energy funds (user defined)

2.2.5 Emissions Impacts

Emissions savings can be realized either through the greening of the natural gas grid or by displacing vehicles powered by internal combustion engines. Natural gas combustion releases 117 pounds of CO_2 per million BTU. One kilogram of hydrogen has an energy content of 0.1346 MMBTU. That means that 7.4 kg of hydrogen have an energy content of one million BTU. Thus, 1 kg injected into the natural gas grid has the potential to eliminate 15.7 pounds (117 pounds/7.4 kg of hydrogen) of CO_2 emissions. To determine how much of this potential could be realized, PNNL has defined the carbon profile of the energy used to power the P2G system. In every hour, HG&E has a different generation and load profile. In certain hours, HG&E is a net consumer of energy. During other hours, it is a net producer. HG&E has obtained data from 40 meters to determine its net position on an hourly bases. The emission impacts of P2G operations were measured on the margin based on when the energy was consumed. If, in a given hour, HG&E produces 40 MWh of energy but consumes only 20MWh of energy, it would be exporting 20MWh of energy to the grid. During that hour, the load of the P2G facility would displace mostly clean hydro exports. Thus, the profile of the HG&E generation mix would be the input into the process and as such, the emissions profile of that set of generators should be used. During another hour, HG&E would be a net importer of energy. In that case, the grid's generation mix should be used. ISO-NE data on generation amount (in MWh) by fuel type was obtained to determine the grid's emissions profile. The emissions produced in the process of water electrolysis are embodied in the emissions profile of the electricity grid at the time of usage. The emissions profile of this process will therefore decrease assuming that there is further decarbonization of the electricity grid The model enables the user to change this mix over time.

The energy produced at HG&E comes from a generation resource mix of hydro, solar, wind, and fossil fuels, with fossil fuels being the lowest used resource. As a result, the energy generation has lower emissions per MWh than ISO-NE, the energy generation resource mix for which consists of a higher percentage of fossil fuels.

To generate the hourly emissions profile for HG&E for the year 2018, data pertaining to the generation mix of both HG&E and ISO-NE was required. HG&E was able to provide, for the year 2018, the hourly fossil fuel generation data, the load and total energy generation data, and monthly energy generation values for each of the resources used by it. The data for carbon dioxide emissions for each fuel type was retrieved from the Energy Information Administration (EIA) for the State of Massachusetts (EIA 2019c). Provided this data, an hourly emissions profile for HG&E production was generated. Similarly, from the ISO-NE website, the hourly generation for each fuel type was retrieved for the year 2018 (ISO-NE 2019). Using this data, the hourly emissions profile for ISO-NE was generated. All the data was transformed to pounds-per-MWh basis for consistency across the analysis.

The final emissions profile gives hourly emissions of carbon dioxide, sulfur dioxide, and nitrous oxide based on the net position of HG&E observed in each hour. These emissions are listed in pounds of each gas emitted per MWh of energy consumption.

LNG incurs an additional emissions cost associated with the transport of the fuel. HG&E secures LNG from suppliers at distances of between 85 and 225 miles from Holyoke, Massachusetts. With an average round trip distance of 300 miles and an average motor fuel economy of 5.5 miles per gallon, a heavy tanker truck would consume roughly 55 gallons of diesel per trip. Every gallon of diesel consumed on the trip would emit 22.4 pounds of CO_2. Each trip delivers 850 Dth. Thus, each trip would emit approximately 1200 pounds of CO_2, which is roughly the equivalent of 1.5 pounds per Dth of delivered LNG. These additional emissions were factored into the model's emissions calculations.

When modeling emissions associated with transportation fuels, we assume that each kilogram of hydrogen would displace 2.07 gallons of gasoline (Elgowainy et al. 2016). While the energy content in a kilogram of hydrogen is roughly equivalent to that in a gallon of gasoline, hydrogen motors are more efficient and that is reflected in the quoted displacement rate. When burned, gasoline emits 157.2 pounds of CO_2 per MMBTU or 19.6 pounds per gallon. The model also enables the user to modify the transportation fuel equivalent of hydrogen and the emissions rate. This added feature will enable the user to evaluate displacement of alternative fuel types or combinations of fuel types.

In terms of valuation, we focus only on CO_2, and we monetize that value using the incentive values outlined in the previous section.

2.3 Treatment of Costs

2.3.1 Annualization Methodology

In order to reach an annualized cost value for the P2G system, a transformative cost methodology must be applied. The methodology described in the sections that follow integrates the aforementioned capital and O&M costs into a pro forma that incorporates assumptions surrounding the required costs of financing a project over the duration of its expected life. This total long-run revenue requirement is then evaluated as an annualized payment in present-day dollars based on an assumed weighted cost of capital for discounting. Any energy costs would be in addition to these costs. The approach detailed in this section was originally presented in Doane et al. 1976.

Table 2.8 provide the parameters necessary to reach an annualized cost for a P2G system. The financial assumptions listed in Table 2.8 were provided by HG&E. Capital costs were detailed in Section 2.1.

Table 2.8. Pro Forma Assumptions

Parameter	Value
Discount rate/weighted cost of capital	4.46%
Escalation rates for all cost and price variables other than capacity and RNS fees	2.0%
Insurance rate as a fraction of the PV of capital costs	0.1002%
Property tax rate	0%
Federal and state income tax rate	0%
Other taxes as a fraction of CI_{pv}	0%
CI = capital investment	

2.3.2 Capital Recovery Factor (CRF)

The internal rate of return for a project (based on the weighted cost of capital) is typically a known factor by project developers and therefore is not discussed in detail here. The capital recovery factor (CRFk,N) can characterize what percentage the annual payments made toward the fully amortized loan are in comparison to the original loan principal.

The formula for calculating the CRF is given in Equation 1.

$$\mathrm{CRF} = \frac{k}{1-(1+k)^{-N}} \tag{1}$$

where: k = Weighted cost of capital
N = System operating lifetime.

Based on the parameters outlined in Table 2.8, a CRF of 7.7 percent was used.

2.3.3 Annual Fixed Charge Rate

The annualized fixed charge rate (FCR) works to take data associated with utility accounts such as applicable taxes and insurance and combine them all into a single number. This rate is required later to determine what proportion of the total annualized system cost is made up of capital costs, income taxes, and other applicable costs. Equation 2 shows the calculation for FCR.

$$\mathrm{FCR} = \frac{1}{1-T}\left(CRF_{k,N} - \frac{T}{N}\right) + B_1 + B_2 \tag{2}$$

where: T = Effective income tax rate
CRF = Capital recovery factor
N = System operating lifetime
B1 = Annual “other taxes” as a fraction of CI_{PV}
B2 = Annual insurance premiums as a percentage of CI_{PV}.

While conducting this calculation, it is important to consider the tax implications associated with the depreciation of the asset over its economic life. Common practice for depreciating property is conducted though the MACRS. This depreciation schedule is provided by the U.S. Internal Revenue Service to provide annual deductions in depreciation (IRS 2019). To accurately compute the FCR, the PV of the applicable schedule percentage found based on the economic life of the asset is used. For example, assuming an 8% discount rate and a 10-year life, the PV of the depreciation schedule would be 0.7059. This percentage is built into the FCR equation, multiplying it by the income tax rate for the project. Using the 10-year MACRS depreciation schedule at an 8% discount rate, and assuming a 24.873% tax rate, T will equal 0.176. Using the parameters outlined in Table 2.8, we use a FCR of 7.8%.

2.3.4 Capital Investment (CI_{pv})

The CI calculation works to generate a single value of all combined investments in PV terms. For systems that require capital investments at numerous time steps, this calculation also should include adjustments for cost growth. Thus, Equation 3 captures PV capital costs.

$$CI_{pv} = (1+g_c)^P \sum_t \left[CI_t \left(\frac{1+g_c}{1+k}\right)^j\right] \tag{3}$$

where: g_c = escalation rate for capital costs
p = first year of commercial operation – price year
CI = capital investment
j = year of investment outlay – first year of commercial operation + 1
k = weighted cost of capital
t = Time.

2.3.5 Present Values of Recurrent Costs (OM_{pv})

Costs that recur throughout the economic life of the P2G system such as O&M costs need to be computed into a single present value. Equation 4 below shows how this is conducted based on cost escalation factors and the discount rate.

$$OM_{pv} = (1+g_x)^P X_o \left(\frac{1+g_x}{k-g_x}\right)\left[1-\left(\frac{1+g_x}{1+k}\right)^N\right] \tag{4}$$

where:
- g_x = Escalation rate for recurring costs
- P = $y_{co} - y_d$, an integer constant
- y_{co} = First year of commercial operation
- y_b = Base year for constant dollars
- X_o = Annual O&M cost
- K = Weighted cost of capital
- N = System operating lifetime.

2.3.6 Annualized System-Resultant Cost (AC)

The annualized cost in this section uses the previous calculations to find an individual annual value. The annualized cost is a sum of values which, if invested, would sustain a stream of withdrawals at interest rate k. Equation 5 works to annualize the present values previously calculated into annual payments of constant values in base year dollars.

$$AC = (1+g)^{-d}\left[FCR \times CI_{pv} + CRF_{k,N} \times OM_{pv}\right] \tag{5}$$

where:
- g_x = Escalation rate for recurrent costs
- d = $y_{co} - y_p$, an integer constant
- y_{co} = First year of commercial operation
- y_p = Price year for cost information
- X_o = Annual recurrent cost
- K = Cost of capital to (and internal rate of return in) a typical utility
- N = System operating lifetime

The weighted cost of capital can be used as a discount rate to transform annualized costs back into a single PV form.

2.4 P2G System Modeling and Optimal Dispatch

The P2G system can be operated as a controllable load to reduce electricity cost and generate value streams from selling end-products and providing grid services. When evaluating the economic benefits of any system with multiple uses, it is essential to avoid the double-counting of benefits. The economic benefits of the P2G system depend on how it is operated. The dispatch of the P2G system affects hydrogen production, compression, and methanation. As the model reviews the landscape of economic opportunities, it makes decisions regarding which value pathway will offer the highest value. The electricity cost and revenues from different grid services also depend on P2G loading levels. Therefore, to estimate the potential benefits, the operation of a P2G system needs to be optimally dispatched in a manner that is technically achievable and avoids the double-counting of benefits.

With hydrogen storage tanks and the optional underground cavern, there are three dimensions of coupling in the P2G optimal dispatch problems. First, different end-products along with pathways 1 (transportation and industrial gas end-use) and 2 (natural gas pipeline injection) compete for hydrogen produced. Second, hydrogen production and regulation services are coupled through the power constraints of the electrolyzer. Third, the operation of the P2G system in different hours are coupled through hydrogen storage tanks and the optional underground cavern. When the monthly demand charge is applicable, another temporal interdependency is introduced to the dispatch of the P2G system.

The economic analysis in this project leverages the modeling capability we developed in our previous projects and tools. Herein, we model the P2G system operation and constraints (including electrolysis, methanation, and production and storage of P2G gases), and its interaction with power systems on an hourly basis through a year. The objective is to maximize the annual net benefits, considering various costs and revenues. In particular, we introduce binary variables to indicate the operating status of the electrolyzer and methanation reactor to capture the minimum loading level of the electrolyzer and calculate the variable O&M cost associated with the methanation reactor. Besides, the maximum operation level is required to model the monthly demand charge, which complicates the dispatch problem. Optimization procedures have been applied to convert the problem to its linear equivalent. The maximum operators are eliminated by introducing inequality constraints that relate the monthly demand to hourly load monthly demand. The other objective function components and constraints are linear. Hence, a large mixed-integer linear programming problem is obtained. The optimal P2G dispatch problem is implemented in Julia in combination with its algebraic modeling library JuMP and solved by an open-source solver named Cbc (Coin-or branch and cut).

Figure 2.6 provides a screenshot of the P2G model input interface. An example of output results is shown in Figure 2.7, including PV and annual cost-benefit analysis results in detail, as well as hourly dispatch results. P2G hourly operation results through a year also are provided, including both the power consumption from different P2G components and hydrogen flow along the two pathways. Figure 2.8 shows a sample of operations in a few days in November.

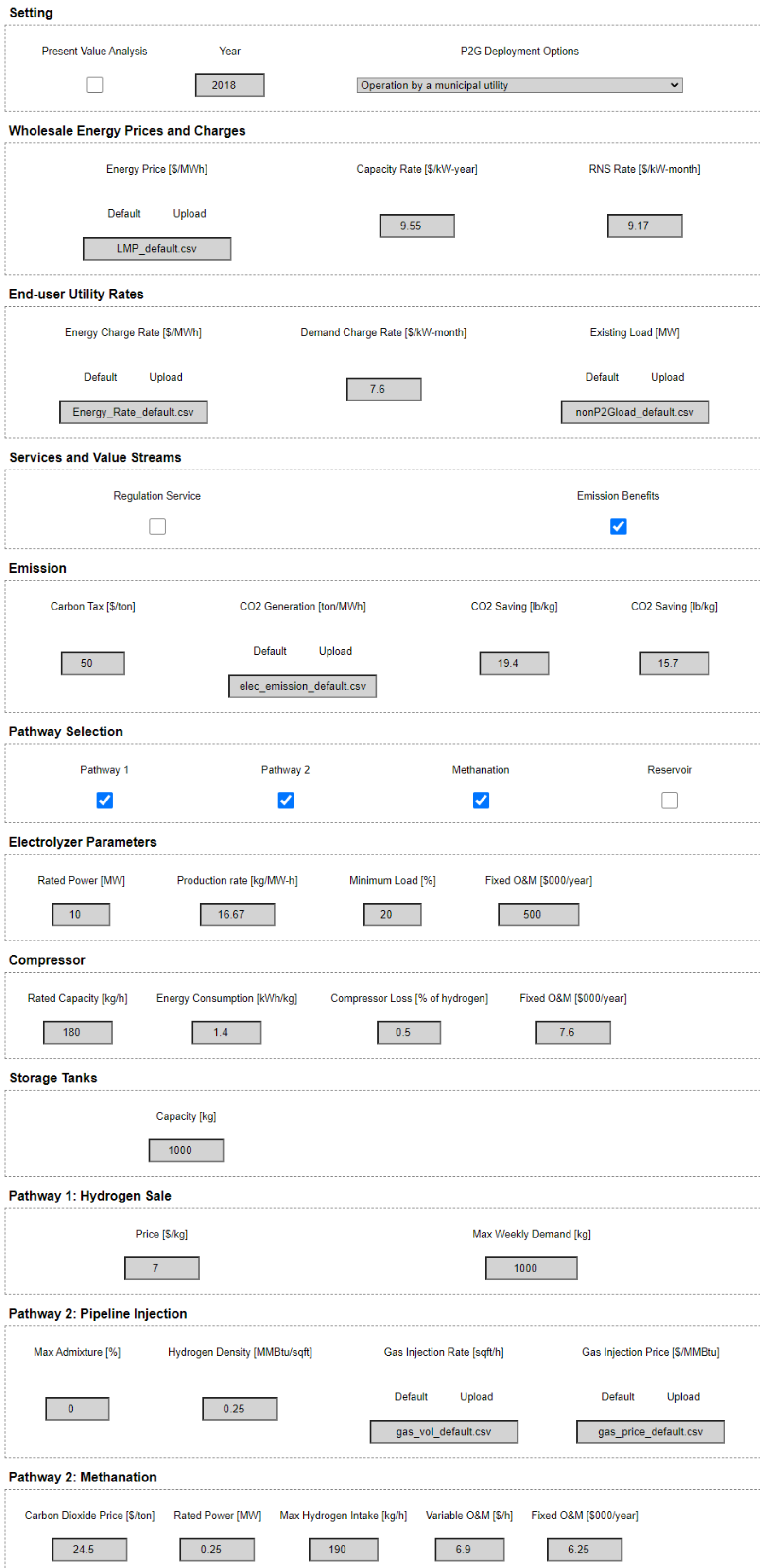


Figure 2.6. P2G Model Input Interface

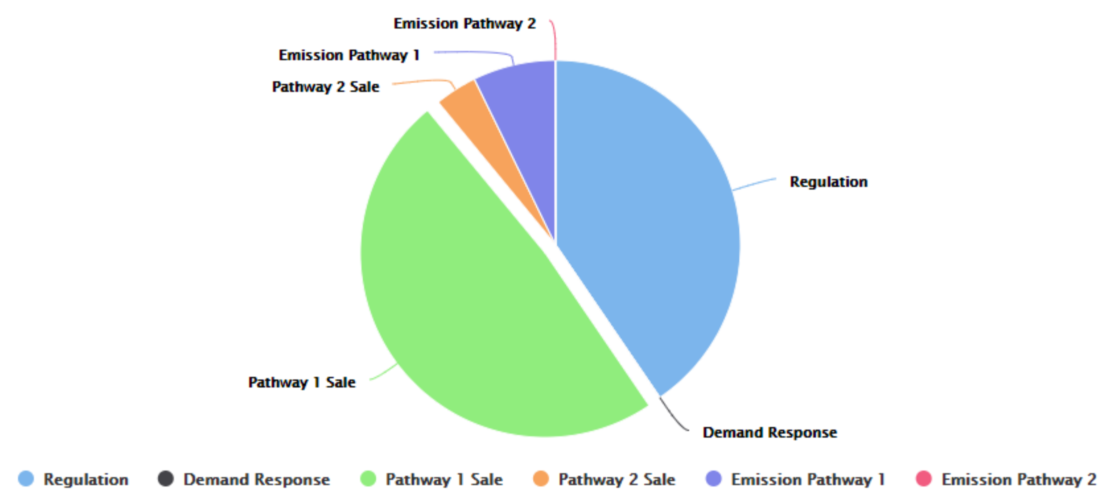
PV Cost and Benefits [$000]

Benefit	Cost	Net-benefits
11,728.571	23,553.35	-11,824.779

Annual Cost and Benefits [$000]

Benefit	Cost	Net-benefits
749.514	790.398	-40.883

Annual Benefits



Annual Cost

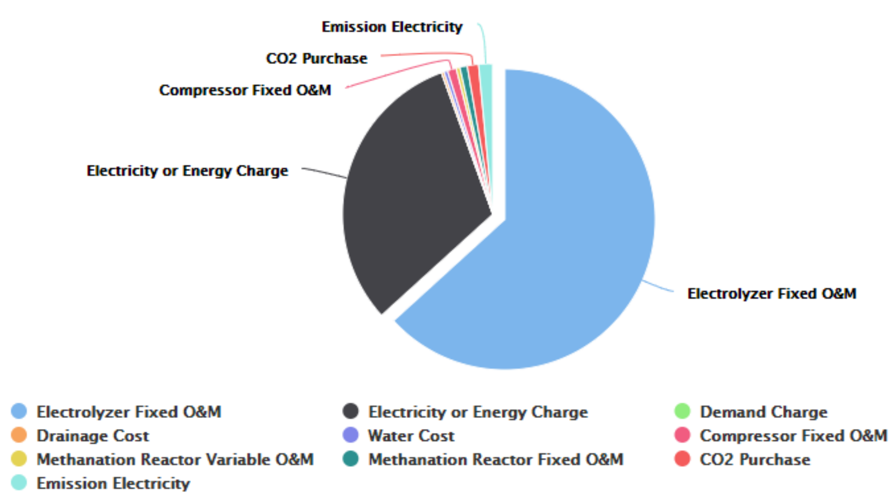


Figure 2.7. Example of P2G Model Cost-Benefit Analysis Results

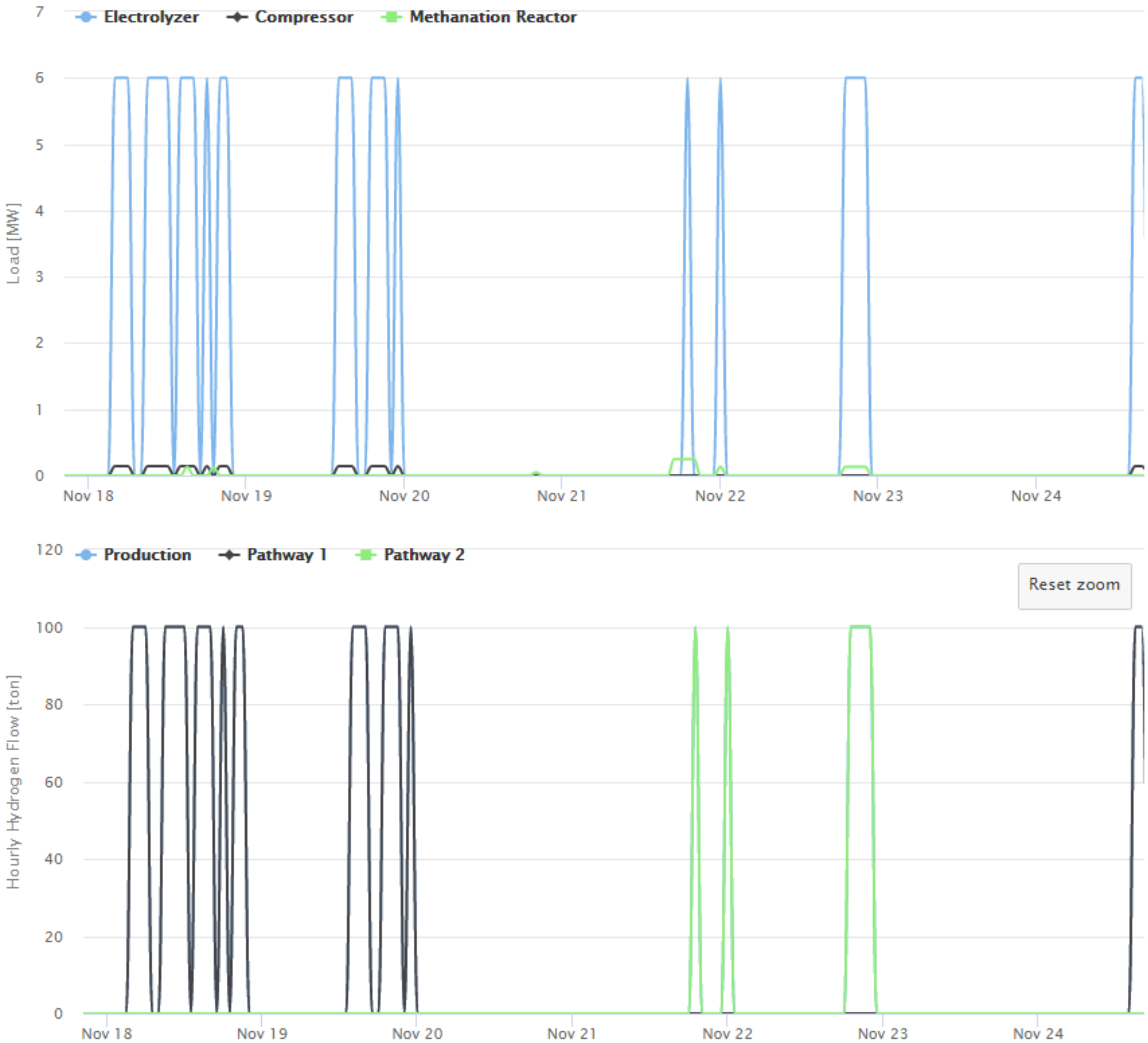


Figure 2.8. P2G Hourly Operation Results

3.0 Economic Results

This economic analysis is designed to determine the value that the P2G unit and accompanying systems can generate for HG&E and the customers it services. In doing so, the analysis and accompanying tool also could be useful to other utilities and developers facing similar investment decisions and those seeking to explore alternative future scenarios where P2G and other hydrogen-based systems can take advantage of lower costs, more market opportunities, and clean energy policies.

The model developed for this study allowed the research team to evaluate a broad range of scenarios with varying parameters associated with prices, demand, technology cost and performance, and policy incentives. Table 3.1 defines the cases evaluated in this study and presents the economic findings with respect to each case. This study evaluated 11 primary cases and 82 sub-cases.

Sources of revenue from hydrogen production evaluated in this study include transportation fuel, injection into the natural gas grid, industrial gas, participation in the ISO-NE frequency regulation market, emissions benefits monetized through clean energy incentives, and demand response/demand charge benefits. This study includes fixed capital and O&M costs, and variable O&M, energy, emissions, and CO_2 input costs.

Total PV benefits and costs incurred over the 20-year economic life of the P2G unit and other subsystems are presented along with return on investment (ROI) ratios. An ROI ratio is calculated by dividing PV benefits by PV costs. An ROI ratio greater than 1.0 indicates a positive economic return. Note the range presented for each case. Within each case, and indeed every sub-case, there are four scenarios that include conditions with and without reservoirs and both RTM and DAM pricing. The description in the table indicates how each case varies from the base case, which is Case 3.

Of the 82 cases evaluated under this study, 76 yielded ROI ratios of under 1.0. Four of the cases generating ROI ratios in excess of 1.0 had lower costs because the capacity of the P2G unit was reduced to 5 MW, suggesting that the base system evaluated in this study at 10 MW was larger than optimal given the landscape of economic opportunity.

Results were most affected by demand for hydrogen as a transportation fuel. At $7/kg, the transportation sector represents the best economic opportunity for hydrogen revenue. In the absence of cavern storage, methanation is required and injection into the natural gas pipeline generates very limited revenue. With depleted natural gas reservoir storage, as explored in this study, hydrogen can bypass the methanation process, thus lowering costs. Benefits are also higher under scenarios with reservoirs because the hydrogen can be stored seasonally to take advantage of higher natural gas prices during winter months when pipeline capacity is constrained and HG&E is paying higher prices for delivered LNG. With that noted, HG&E does not have any reservoir storage capacity.

Participation in the frequency regulation market improves project economics considerably by both generating revenue and improving the value proposition for injection into the natural gas grid. Under scenarios with frequency regulation, revenue associated with natural gas grid injection is much higher because participation in the frequency regulation market effectively subsidizes production costs by providing the operator a source of revenue obtained by varying production rates while following an AGC signal. More detail is provided for each case in the remainder of this chapter.

Table 3.1. Results by Scenario Examined in this Report

Case #	Case Definition	20-Year PV Benefits ($Millions)	20-Year PV Costs ($Millions)	Return on Investment Ratio
1	Hydrogen for transportation fuel only	5.6-5.7	21.5-22.1	0.26
2	Hydrogen for transportation fuel and natural gas injection	5.6-6.2	21.6-22.4	0.25-0.28
3	Hydrogen for transportation fuel and natural gas injection, with additional revenue from varying P2G unit electrical load to provide frequency regulation (base case)	8.5-15.7	23.2-29.0	0.37-0.54
4a	Industrial gas sold at $2/kg	10.6-16.7	25.6-30.5	0.41-0.55
4b	Industrial gas sold at $4/kg	12.3-18.5	25.7-30.7	0.48.-0.60
5a	Doubling of demand for transportation fuel	14.8-20.9	24.4-29.3	0.61-0.71
5b	Tripling of demand for transportation fuel	21.2-26.3	25.8-29.9	0.82-0.88
5c	Transportation fuel price of $4/kg	6.0-13.3	23.1-29.0	0.26-0.46
5d	Transportation fuel price of $10/kg	10.9-18.2	23.2-29.0	0.47-0.63
6a	Allow 1% hydrogen injected into natural gas grid w/o methanation	8.5-15.7	23.0-28.9	0.37-0.54
6b	Allow 2% hydrogen injected into natural gas grid w/o methanation	8.6-15.7	23.1-28.9	0.37-0.54
6c	Allow 5% hydrogen injected into natural gas grid w/o methanation	8.7-15.7	23.2-28.9	0.38-0.54
7	Assume that energy prices are zero with no emissions from electricity used to power the electrolyzer from March 19-June 20	11.8-19.2	23.6-27.0	0.50-0.71
8a	Carbon tax at $50/ton	16.3-31.3	29.4-39.9	0.56-0.78
8b	LCFS at $2.5/kg	10.5-17.8	23.2-29.0	0.45-0.61
9a	P2G unit paying retail prices, served by a distribution utility	11.0-13.6	25.0-27.0	0.44-0.50
9b	P2G unit paying retail prices, served by a municipal utility	11.1-13.5	24.9-26.8	0.45-0.50
10a	Case 3 with 5 MW P2G unit	7.4-10.5	13.6-16.2	0.54-0.65
10b	Case 5b with 5 MW P2G unit	20.1-21.7	16.8-18.1	1.19-1.21
10c	Case 8a with 5 MW P2G unit	11.0-18.2	16.3-21.6	0.68-0.84
10d	Case 7 with 5 MW P2G unit	9.0-12.2	13.7-15.2	0.65-0.80
11	Zero energy prices and emissions 3/19-6/20 with carbon tax and double transportation demand	26.7-40.1	28.8-36.2	0.93-1.12

3.1 Case 1 Results

In Case 1, the P2G unit is used exclusively for production of hydrogen for sale in the transportation sector as defined in Section 2.2.3. Under this case the P2G unit operates 350–356 hours per year and delivers 52.0 tons of hydrogen. No hydrogen is delivered for natural gas injection and, therefore, no cavern storage or methanation are required. Annualized revenue totals $432–$434 thousand, generating $5.6–$5.7 million in PV benefits over the 20-year economic life of the systems. When compared to total PV costs of $21.5–$22.1 million, Case 1 produces an ROI ratio of 0.26. Case 1 results are presented in Table 3.2 and Figure 3.1. Note that the DAM price scenario results in higher costs. While counterintuitive because DAM prices are typically lower than RTM prices, the simulation tool took advantage of the volatility in the RTM to produce hydrogen when RTM prices were at their lowest.

Table 3.2. Detailed Economic Results – Case 1

Case	Transportation Fuel ($Thousands)	Total Benefits ($Thousands)	Total Cost ($Thousands)	ROI	Hours of Operation	Hydrogen Production (tons)
Case 1|RTM|No Reservoir	5,639	5,639	21,482	0.26	350	52
Case 1|DAM|No Reservoir	5,659	5,659	22,147	0.26	356	52

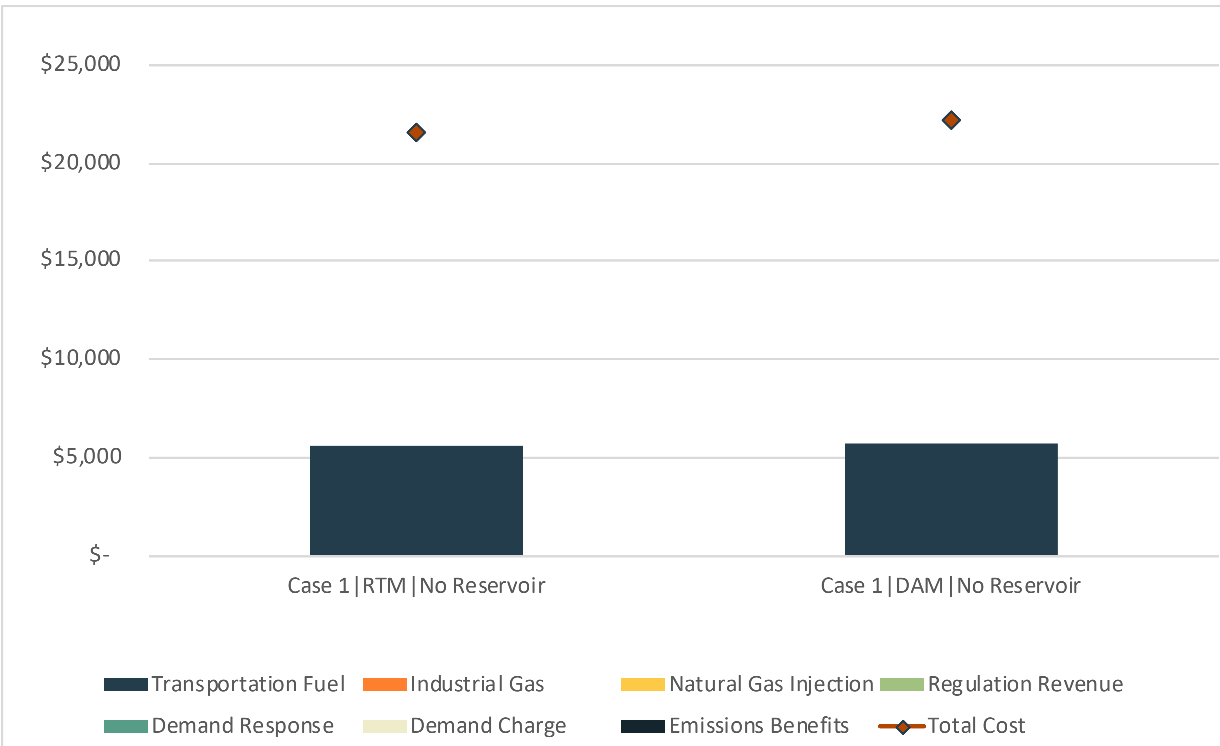


Figure 3.1. Economic Results for Case 1 – Hydrogen Reserved for Transportation Fuel ($Thousands)

3.2 Case 2 Results

In Case 2, the P2G unit is used for production of hydrogen for sale in the transportation sector as defined in Section 2.2.3 and injected into the natural gas grid as defined in Section 2.2.2. Under this case the P2G unit operates 325–562 hours per year delivering 52–89 tons of hydrogen. Hydrogen is delivered for natural gas injection; therefore, cavern storage and methanation are included in this scenario. Annualized revenue totals $433–$472 thousand, generating $5.6–$6.2 million in PV benefits over the 20-year economic life of the systems. When compared to total PV costs of $21.6–$22.4 million, Case 2 produces ROI ratios of 0.25–0.28. Case 2 results are presented in Table 3.3 and Figure 3.2.

Benefits are higher under the scenarios with reservoirs because the hydrogen can be stored seasonally to take advantage of higher natural gas prices during winter months when pipeline capacity is constrained, and HG&E is paying higher prices for delivered LNG. Routing hydrogen through a reservoir also avoids variable O&M costs for methanation and, much more significantly, CO_2 input costs. Costs are also greater in this and other scenarios with higher levels of hydrogen production due to variable operation costs associated with O&M, CO_2 input, emissions, and energy purchases.

Table 3.3. Detailed Economic Results – Case 2

Case	Transportation Fuel ($Thousands)	Natural Gas Injection ($Thousands)	Total Benefits ($Thousands)	Total Cost ($Thousands)	ROI	Hours of Operation	Hydrogen Production (tons)
Case 2 | RTM | No Reservoir	5,640	7	5,648	21,577	0.26	337	53
Case 2 | RTM | Reservoir	5,641	525	6,166	22,061	0.28	562	89
Case 2 | DAM | No Reservoir	5,656	--	5,656	22,280	0.25	325	52
Case 2 | DAM | Reservoir	5,659	89	5,748	22,445	0.26	389	58

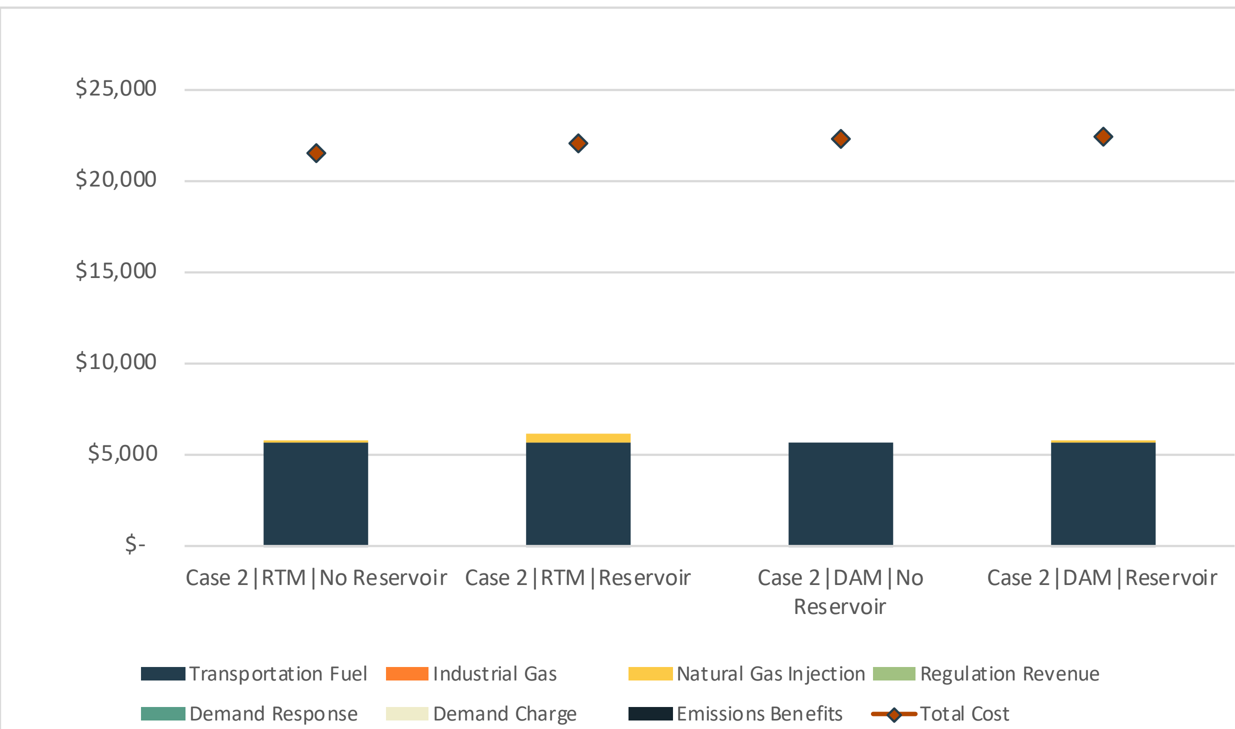


Figure 3.2. Economic Results for Case 2 – Hydrogen Produced for Transportation Fuel and the Natural Gas Grid ($Thousands)

3.3 Case 3 Results

In Case 3, the P2G unit, while providing hydrogen for sale in the transportation sector and injection into the natural gas grid, is bid into the ISO-NE frequency regulation market as an ATRR (see Section 2.2.1 for details regarding frequency regulation market participation). Note that this market can be saturated and this analysis assumes that the small bid offered by the P2G plant will be accepted. Under this case the P2G unit operates 754–2,884 hours per year delivering 77–291 tons of hydrogen. Annualized revenue totals $0.65–$1.2 million, generating $8.5–$15.7 million in PV benefits over the 20-year economic life of the systems. When compared to total PV costs of $23.2–$29.0 million, Case 3 produces ROI ratios of 0.37–0.54. Under this scenario, revenue associated with natural gas injection is much higher because participation in the frequency regulation market effectively subsidizes production costs by providing the operator a source of revenue obtained by varying production rates while following an AGC signal. For scenarios with no reservoir, the high costs associated with methanation reduce revenue opportunities for both natural gas injection and frequency regulation. Case 3 results are presented in Table 3.4 and Figure 3.3. Case 3 serves as the base case.

Table 3.4. Detailed Economic Results – Case 3

Case	Transportation Fuel ($Thousands)	Natural Gas Injection ($Thousands)	Regulation Revenue ($Thousands)	Total Benefits ($Thousands)	Total Cost ($Thousands)	ROI	Hours of Operation	Hydrogen Production (tons)
Case 3|RTM|No Reservoir	5,695	174	2,588	8,458	23,160	0.37	754	77
Case 3|RTM|Reservoir	5,695	3,411	5,135	14,242	28,169	0.51	2,884	291
Case 3|DAM|No Reservoir	5,695	173	4,008	9,876	24,163	0.41	788	78
Case 3|DAM|Reservoir	5,695	3,173	6,862	15,731	29,011	0.54	2,738	274

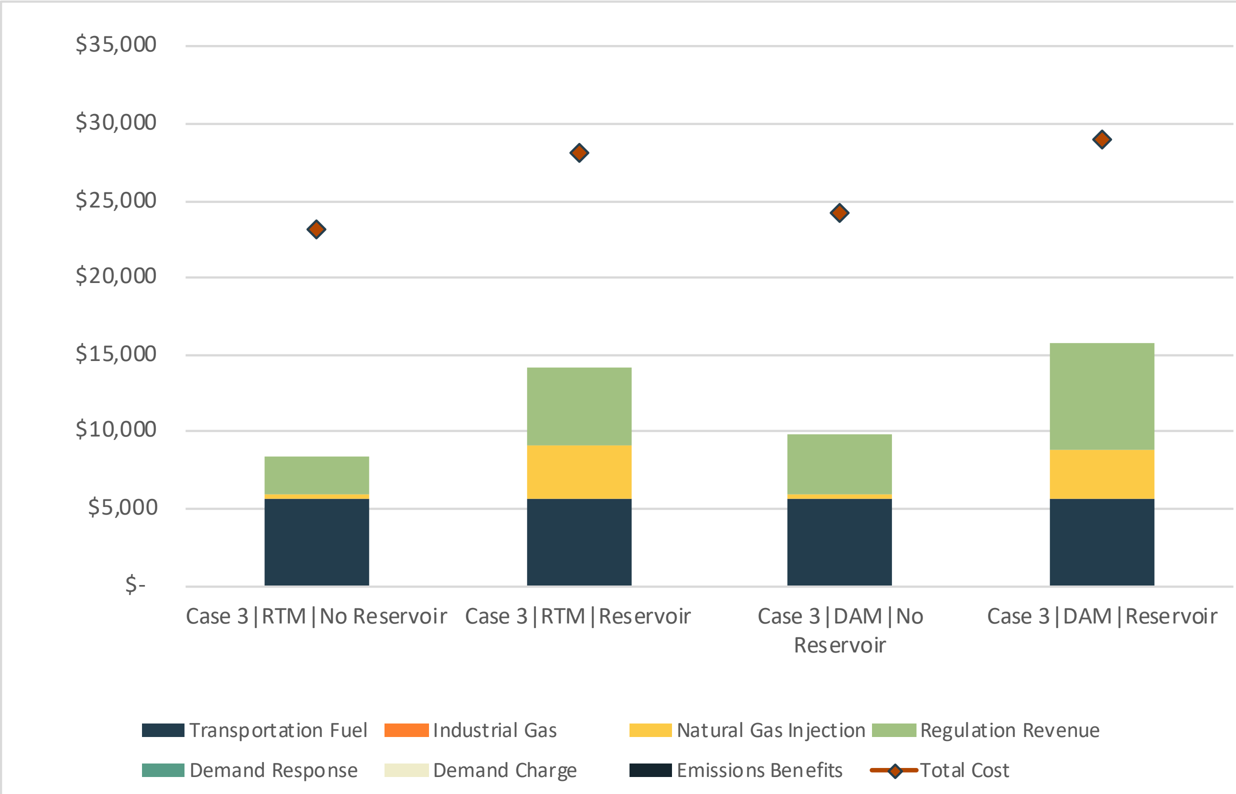


Figure 3.3. Economic Results for Case 3 – Hydrogen Produced for Transportation Fuel and the Natural Gas Grid, Frequency Regulation Provided by P2G Unit ($Thousands)

3.4 Case 4 Results

Case 4 mirrors Case 3 but adds hydrogen sales for industrial gas under two scenarios, with price varied from $2/kg (Case 4a) to $4/kg (Case 4b). See Section 2.2.3 for more detail on the assumptions supporting this scenario. Under this case the P2G unit operates 1,128–2,943 hours per year delivering 114–297 tons of hydrogen. Annualized revenue totals $0.8–$1.4 million, generating $10.6–$18.5 million in PV benefits over the 20-year economic life of the systems. When compared to total PV costs of $25.6–$30.7 million, Case 4 produces ROI ratios of

0.41–0.60. Costs are driven up by higher operational costs, including the need to purchase an additional two storage tanks to serve an industrial customer. Under this scenario, industrial gas sales provide a boost in total PV revenue ($1.6–$3.3 million in additional revenue) that while significant, falls short of transportation fuel revenue due to lower industrial gas prices. Case 4 results are presented in Table 3.5 and Figure 3.4.

Table 3.5. Detailed Economic Results – Case 4

Case	Transportation Fuel ($Thousands)	Industrial Gas ($Thousands)	Natural Gas Injection ($Thousands)	Regulation Revenue ($Thousands)	Total Benefits ($Thousands)	Total Cost ($Thousands)	ROI	Hours of Operation	Hydrogen Production (tons)
Case 4a | RTM | No Reservoir	5,695	1,594	75	3,249	10,614	25,627	0.41	1,128	114
Case 4a | RTM | Reservoir	5,695	1,596	2,762	5,208	15,261	29,745	0.51	2,939	297
Case 4a | DAM | No Reservoir	5,695	1,589	60	4,741	12,086	26,568	0.45	1,131	114
Case 4a | DAM | Reservoir	5,695	1,595	2,508	6,928	16,726	30,566	0.55	2,782	279
Case 4b | RTM | No Reservoir	5,696	3,216	75	3,304	12,292	25,708	0.48	1,132	115
Case 4b | RTM | Reservoir	5,696	3,217	2,762	5,263	16,938	29,825	0.57	2,943	297
Case 4b | DAM | No Reservoir	5,696	3,252	60	4,830	13,838	26,712	0.52	1,141	115
Case 4b | DAM | Reservoir	5,696	3,254	2,508	7,020	18,478	30,707	0.60	2,792	280

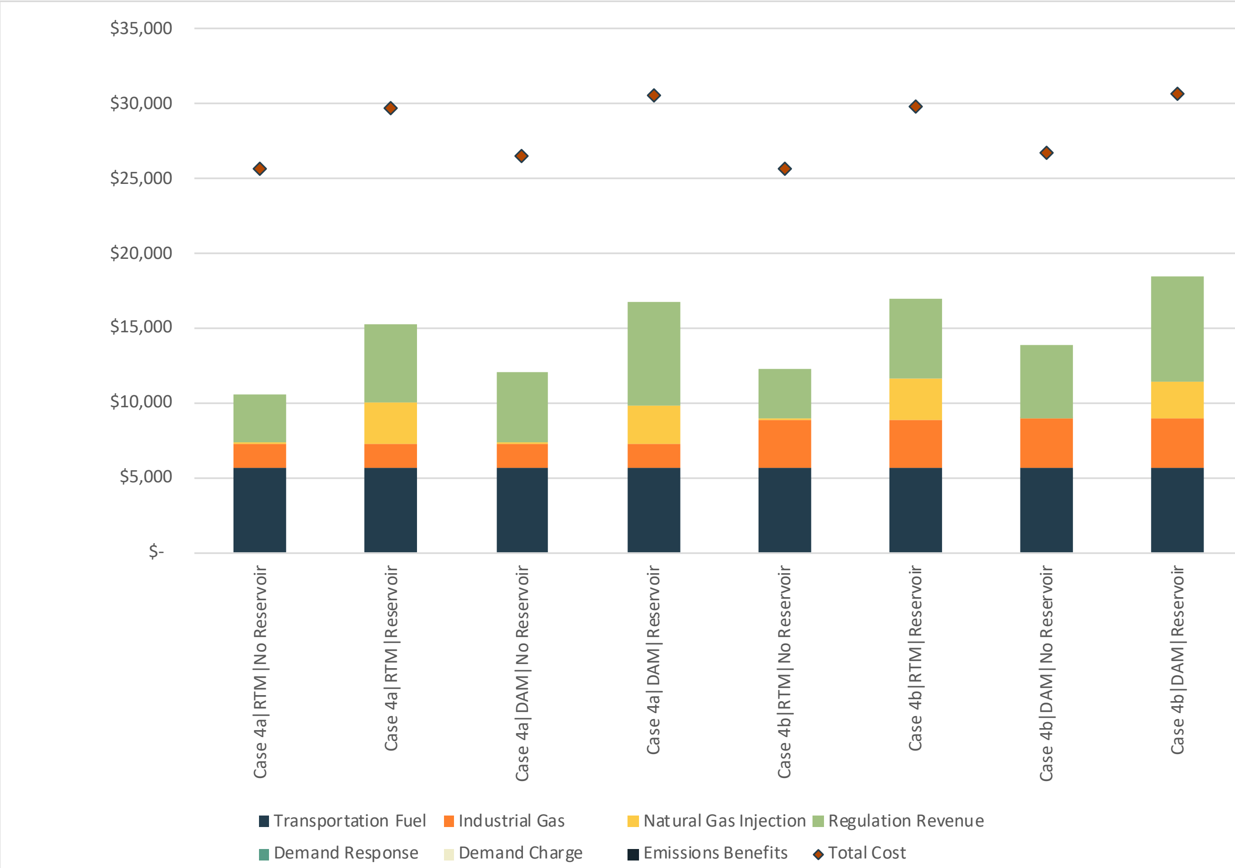


Figure 3.4. Economic Results for Case 4 – Base Case plus Hydrogen Produced for Industrial Gas ($thousands)

3.5 Case 5 Results

Case 5 mirrors Case 3 but varies transportation fuel demand and prices. In Case 5a, demand for transportation fuel is doubled. Demand is tripled, as compared to the base case, in Case 5b. Cases 5c and 5d vary hydrogen prices in the transportation sector from $4–$10 per kg, respectively. Under this case, the P2G unit operates 754–2,949 hours per year delivering 77–311 tons of hydrogen. Annualized revenue totals $0.5–$2.0 million, generating $6.0–$26.3 million in PV benefits over the 20-year economic life of the systems. When compared to total PV costs of $23.1–$29.9 million, Case 5 produces ROI ratios of 0.26–0.88. Case 5 results are presented in Table 3.6 and Figure 3.5.

Case 5b with reservoir yields an ROI ratio of 0.88. Case 5a and Case 5b yield higher revenue than previous cases because hydrogen in the transportation sector fetches higher prices than when sold in the other markets considered in this report. As the demand for hydrogen as a transportation fuel expands, profit potential expands along with it. Even when tripling demand for transportation fuel, the P2G unit still operates under 3,000 hours (34% of hours in a year). With the unit sitting idle 66% of all hours, there is significant capacity to ramp up production as necessary as demand for transportation fuel grows. In recognition of this excess capacity, a case considered later in this report evaluates a scaled down 5 MW P2G unit.

Table 3.6. Detailed Economic Results – Case 5

Case	Transportation Fuel ($Thousands)	Natural Gas Injection ($Thousands)	Regulation Revenue ($Thousands)	Total Benefits ($Thousands)	Total Cost ($Thousands)	ROI	Hours of Operation	Hydrogen Production (tons)
Case 5a | RTM | No Reservoir	11,391	75	3,372	14,838	24,439	0.61	1,138	116
Case 5a | RTM | Reservoir	11,391	2,762	5,331	19,485	28,555	0.68	2,949	298
Case 5a | DAM | No Reservoir	11,391	60	4,828	16,279	25,336	0.64	1,141	115
Case 5a | DAM | Reservoir	11,391	2,508	7,020	20,919	29,329	0.71	2,792	280
Case 5b | RTM | No Reservoir	17,086	22	4,094	21,203	25,802	0.82	1,581	160
Case 5b | RTM | Reservoir	17,086	2,198	5,545	24,830	29,091	0.85	3,073	311
Case 5b | DAM | No Reservoir	17,086	16	5,688	22,791	26,772	0.85	1,586	160
Case 5b | DAM | Reservoir	17,086	1,934	7,270	26,290	29,888	0.88	2,910	292
Case 5c | RTM | No Reservoir	3,255	174	2,568	5,997	23,140	0.26	754	77
Case 5c | RTM | Reservoir	3,255	3,411	5,135	11,801	28,169	0.42	2,884	291
Case 5c | DAM | No Reservoir	3,255	183	4,059	7,496	24,223	0.31	803	80
Case 5c | DAM | Reservoir	3,255	3,173	6,862	13,290	29,011	0.46	2,738	274
Case 5d | RTM | No Reservoir	8,136	176	2,575	10,887	23,150	0.47	758	77
Case 5d | RTM | Reservoir	8,136	3,411	5,135	16,683	28,169	0.59	2,884	291
Case 5d | DAM | No Reservoir	8,137	186	4,047	12,370	24,228	0.51	809	80
Case 5d | DAM | Reservoir	8,136	3,173	6,862	18,172	29,011	0.63	2,738	274

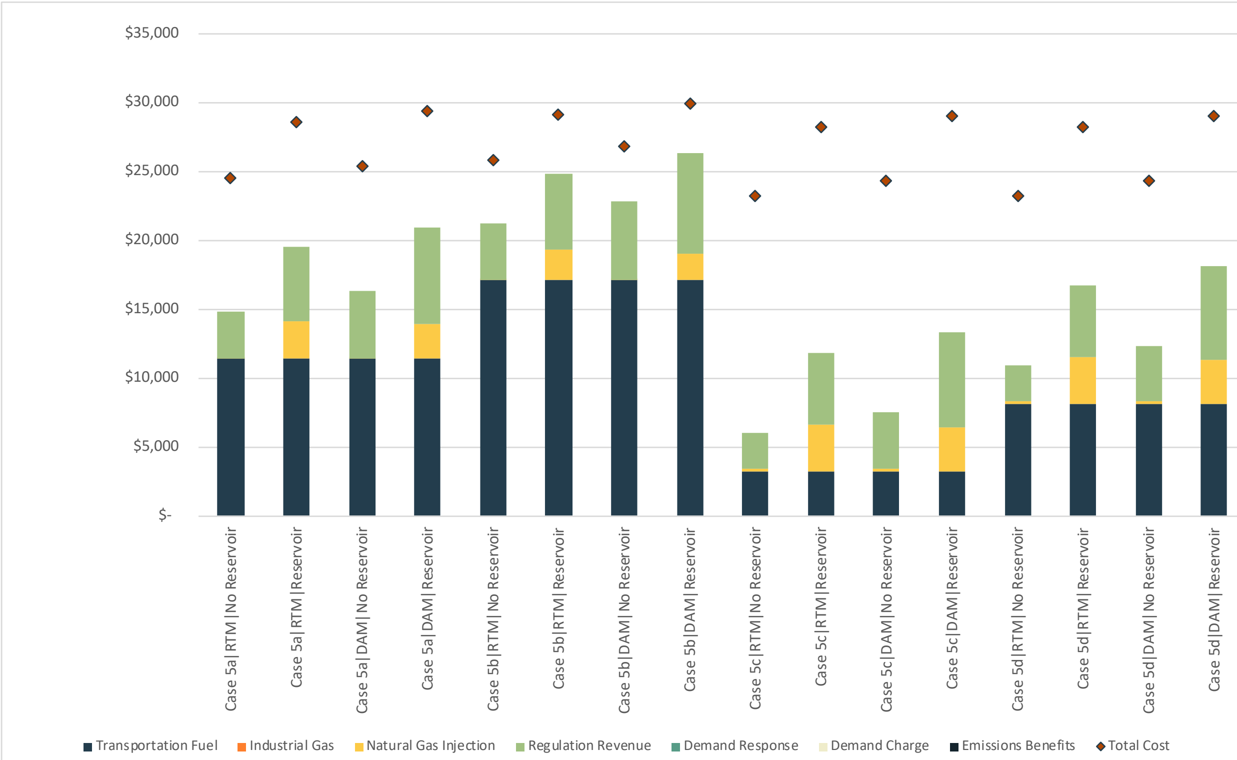


Figure 3.5. Economic Results for Case 5 – Base Case Modified with Varied Transportation Fuel Demand and Prices ($Thousands)

3.6 Case 6 Results

Case 6 mirrors Case 3 but allows for hydrogen to be injected directly into the natural gas grid without methanation provided the hydrogen admixture rate in the pipeline remains below 1% by volume (6a), 2% (6b), and 3% (6c). Under this case, the P2G unit operates 785–2,884 hours per year delivering 80–291 tons of hydrogen. Annualized revenue totals $0.65–$1.2 million, generating $8.5–$15.7 million in PV benefits over the 20-year economic life of the systems. When compared to total PV costs of $23.0–$28.9 million, Case 6 produces ROI ratios of 0.37–0.54. Case 6 results are presented in Table 3.7 and Figure 3.6. The primary finding associated with this case is that even in the absence of methanation costs, the preferred path for hydrogen involves seasonal storage in a cavern. In the absence of cavern storage, profit associated with direct hydrogen injection into the HG&E natural gas pipeline remains low.

Table 3.7. Detailed Economic Results – Case 6

Case	Transportation Fuel ($Thousands)	Natural Gas Injection ($Thousands)	Regulation Revenue ($Thousands)	Total Benefits ($Thousands)	Total Cost ($Thousands)	ROI	Hours of Operation	Hydrogen Production (tons)
Case 6a | RTM | No Reservoir	5,695	214	2,618	8,527	23,062	0.37	785	80
Case 6a | RTM | Reservoir	5,695	3,411	5,135	14,242	28,049	0.51	2884	291
Case 6a | DAM | No Reservoir	5,695	241	4,211	10,148	24,258	0.42	855	86
Case 6a | DAM | Reservoir	5,695	3,173	6,862	15,731	28,891	0.54	2738	274
Case 6b | RTM | No Reservoir	5,695	258	2,681	8,635	23,140	0.37	824	84
Case 6b | RTM | Reservoir	5,695	3,411	5,135	14,242	28,049	0.51	2884	291
Case 6b | DAM | No Reservoir	5,695	298	4,311	10,304	24,381	0.42	908	91
Case 6b | DAM | Reservoir	5,695	3,173	6,862	15,731	28,891	0.54	2738	274
Case 6c | RTM | No Reservoir	5,695	285	2,727	8,708	23,194	0.38	846	86
Case 6c | RTM | Reservoir	5,695	3,411	5,135	14,242	28,049	0.51	2884	291
Case 6c | DAM | No Reservoir	5,695	351	4,414	10,461	24,515	0.43	958	96
Case 6c | DAM | Reservoir	5,695	3,173	6,862	15,731	28,891	0.54	2738	274

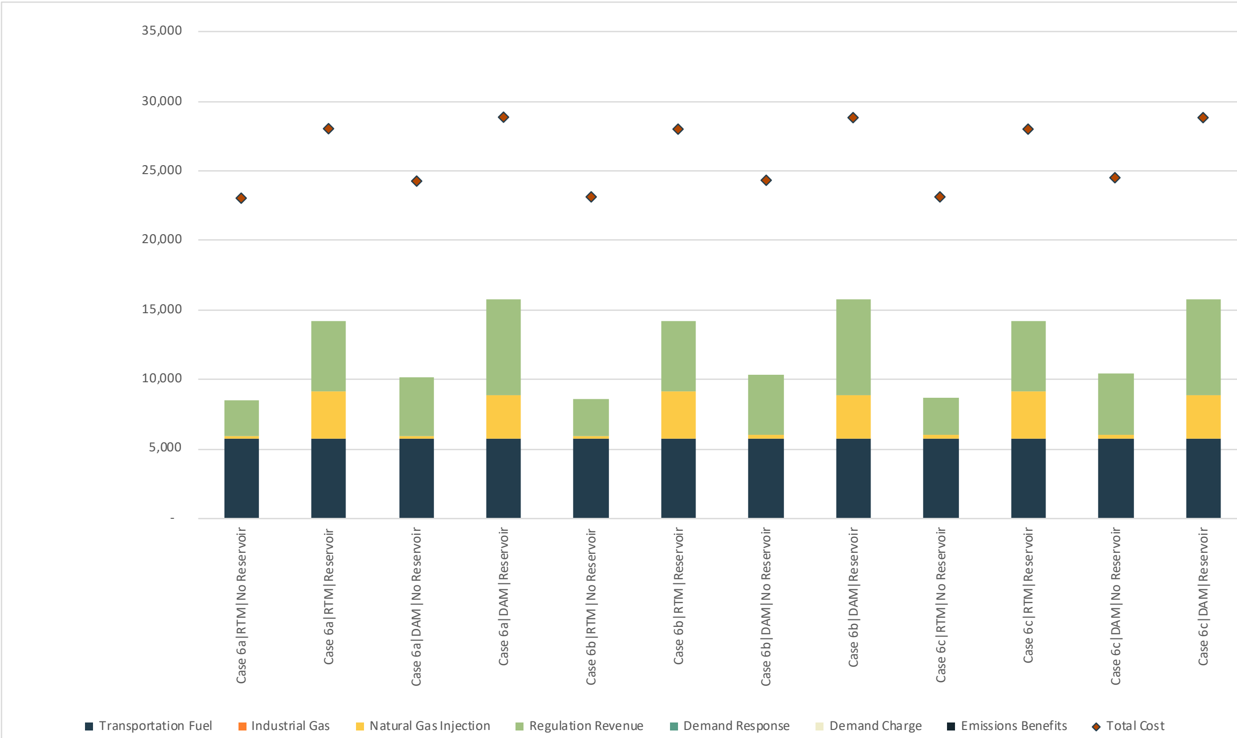


Figure 3.6. Economic Results for Case 6 – Base Case Modified with Allowances for Hydrogen Injection into the Natural Gas Pipeline at Rates of 1%, 2%, and 5% by Volume ($Thousands)

3.7 Case 7 Results

Case 7 mirrors Case 3 but assumes that electricity prices and emissions fall to zero from March 19-June 20. The concept explored in this case is one where spring runoff forces a run-of-the-river hydro system into curtailments. The energy is free because it would otherwise be spilled to avoid negative energy prices or penalties.

Under this case, the P2G unit expands operations to take advantage of the zero price hours in the spring, operating 2,752–4,026 hours per year and delivering 276–487 tons of hydrogen annually. Annualized revenue totals $0.9–$1.5 million, generating $11.8–$19.2 million in PV benefits over the 20-year economic life of the systems. When compared to total PV costs of $23.6–$27.0 million, Case 7 produces ROI ratios of 0.50–0.71. Case 7 results are presented in Table 3.8 and Figure 3.7. This case shows promise, particularly if excess production could be used to meet demand for hydrogen in the transportation sector.

Table 3.8. Detailed Economic Results – Case 7

Case	Transportation Fuel ($Thousands)	Natural Gas Injection ($Thousands)	Regulation Revenue ($Thousands)	Total Benefits ($Thousands)	Total Cost ($Thousands)	ROI	Hours of Operation	Hydrogen Production (tons)
Case 7 | RTM | No Reservoir	5,695	1,217	4,910	11,823	23,627	0.50	2,752	276
Case 7 | RTM | Reservoir	5,695	6,216	5,826	17,737	26,281	0.67	4,014	487
Case 7 | DAM | No Reservoir	5,695	1,235	6,093	13,024	24,299	0.54	2,815	281
Case 7 | DAM | Reservoir	5,695	6,231	7,271	19,197	27,042	0.71	4,026	487

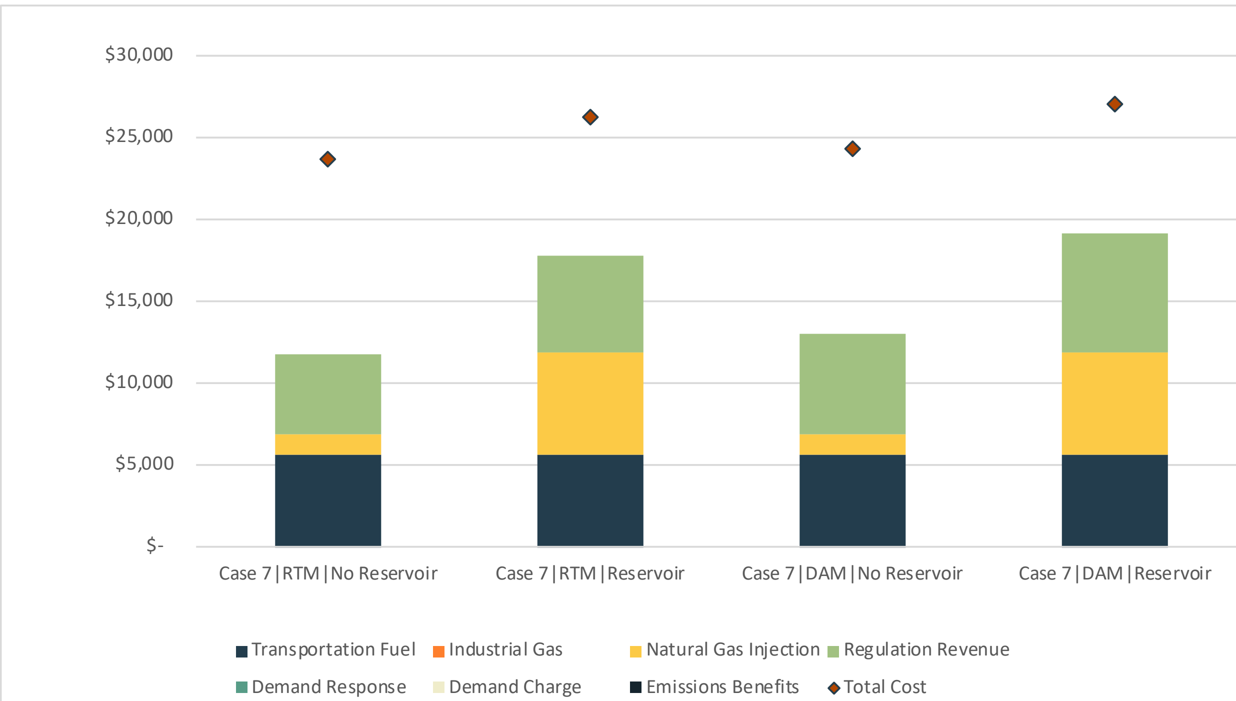


Figure 3.7. Economic Results for Case 7 – Base Case Modified by Assuming Zero Price, Zero Emissions Electricity Available in Spring ($Thousands)

3.8 Case 8 Results

Case 8 mirrors Case 3 but explores the impact of clean energy incentives. More specifically, it includes a $50/ton carbon tax (8a) and an LCFS that increases the price of hydrogen as a transportation fuel by $2.50/kg. Note that in the carbon tax case, emissions benefits are defined. In Case 8b, the LCFS scenario, revenue from hydrogen sold as transportation fuel grows.

Under this case, the P2G unit operates 758-5,859 hours per year, generating 77-636 tons of hydrogen. Annualized revenue totals $0.8-$2.4 million, generating $10.5-$31.3 million in PV benefits over the 20-year economic life of the systems. When compared to total PV costs of $23.2-$39.9 million, Case 8 produces ROI ratios of 0.45-0.78. Case 8 results are presented in Table 3.9 and Figure 3.8.

Table 3.9. Detailed Economic Results – Case 8

Case	Transportation Fuel ($Thousands)	Natural Gas Injection ($Thousands)	Regulation Revenue ($Thousands)	Emissions Benefits ($Thousands)	Total Benefits ($Thousands)	Total Cost ($Thousands)	ROI	Hours of Operation	Hydrogen Production (tons)
Case 8a | RTM | No Reservoir	5,695	1,462	4,959	4,220	16,337	29,359	0.56	2,936	293
Case 8a | RTM | Reservoir	5,695	8,259	8,158	9,201	31,314	39,929	0.78	5,859	636
Case 8a | DAM | No Reservoir	5,695	1,308	6,603	3,879	17,486	30,095	0.58	2,845	269
Case 8a | DAM | Reservoir	5,695	7,303	9,585	8,213	30,796	39,341	0.78	5,479	568
Case 8b | RTM | No Reservoir	7,730	176	2,575	--	10,480	23,150	0.45	758	77
Case 8b | RTM | Reservoir	7,730	3,411	5,135	--	16,276	28,169	0.58	2,884	291
Case 8b | DAM | No Reservoir	7,730	183	4,044	--	11,957	24,210	0.49	802	80
Case 8b | DAM | Reservoir	7,730	3,173	6,862	--	17,765	29,011	0.61	2,738	274

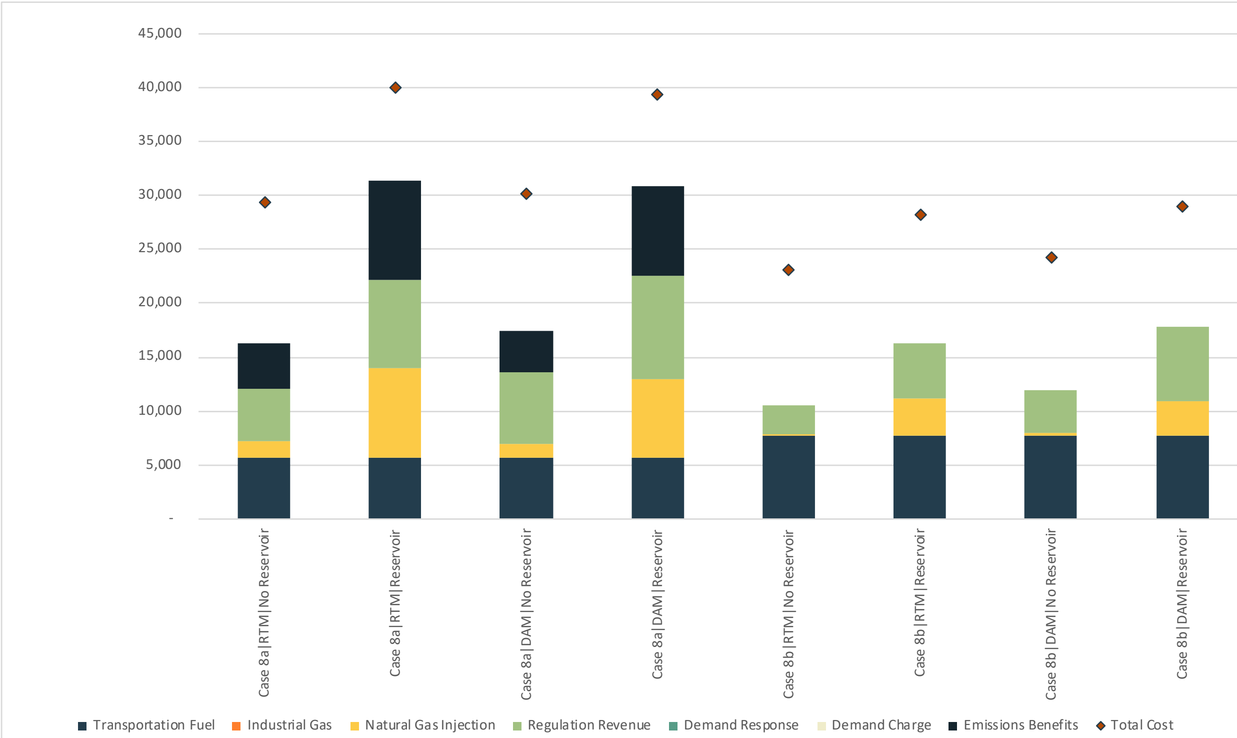


Figure 3.8. Economic Results for Case 8 – Base Case Modified through Addition of Clean Energy Incentives ($Thousands)

3.9 Case 9 Results

Case 9 presents alternative structures for obtaining electricity. Case 9a is essentially Case 3 except the P2G unit would be served by a distribution utility. Under the distribution utility structure, there are opportunities to power down the P2G unit to reduce demand charges and to obtain demand response revenue. Case 9b considers a scenario where the P2G unit is served by a municipal utility. In Case 9b, there are no demand charge reduction or demand response opportunities.

Under this case, the P2G unit operates 835–1337 hours per year, generating 82–130 tons of hydrogen. Annualized revenue totals $0.84-$1.0 million, generating $11.0-$13.6 million in PV benefits over the 20-year economic life of the systems. When compared to total PV costs of $24.9-$27.0 million, Case 9 produces ROI ratios of 0.44-0.50. Case 9 results are presented in Table 3.10 and Figure 3.9. When compared to Case 3, which evaluates a system owned and operated by a municipal utility, electricity costs under Case 9 are higher because the P2G operator is paying retail rates. As a result, the top-end ROI ratio for Case 9 is slightly lower (0.50 compared to 0.55) than that measured for Case 3.

Table 3.10. Detailed Economic Results – Case 9

Case	Transportation Fuel ($Thousands)	Natural Gas Injection ($Thousands)	Regulation Revenue ($Thousands)	Demand Response Revenue ($Thousands)	Total Benefits ($Thousands)	Total Cost ($Thousands)	ROI	Hours of Operation	Hydrogen Production (tons)
Case 9a | Retail | No Reservoir	5,696	215	5,087	72	11,070	25,019	0.44	837	82
Case 9a | Retail | Reservoir	5,696	1,121	6,623	149	13,588	27,047	0.50	1,337	130
Case 9b | Retail | No Reservoir	5,696	214	5,197	--	11,108	24,931	0.45	835	82
Case 9b | Retail | Reservoir	5,696	1,097	6,675	--	13,468	26,825	0.50	1,319	129

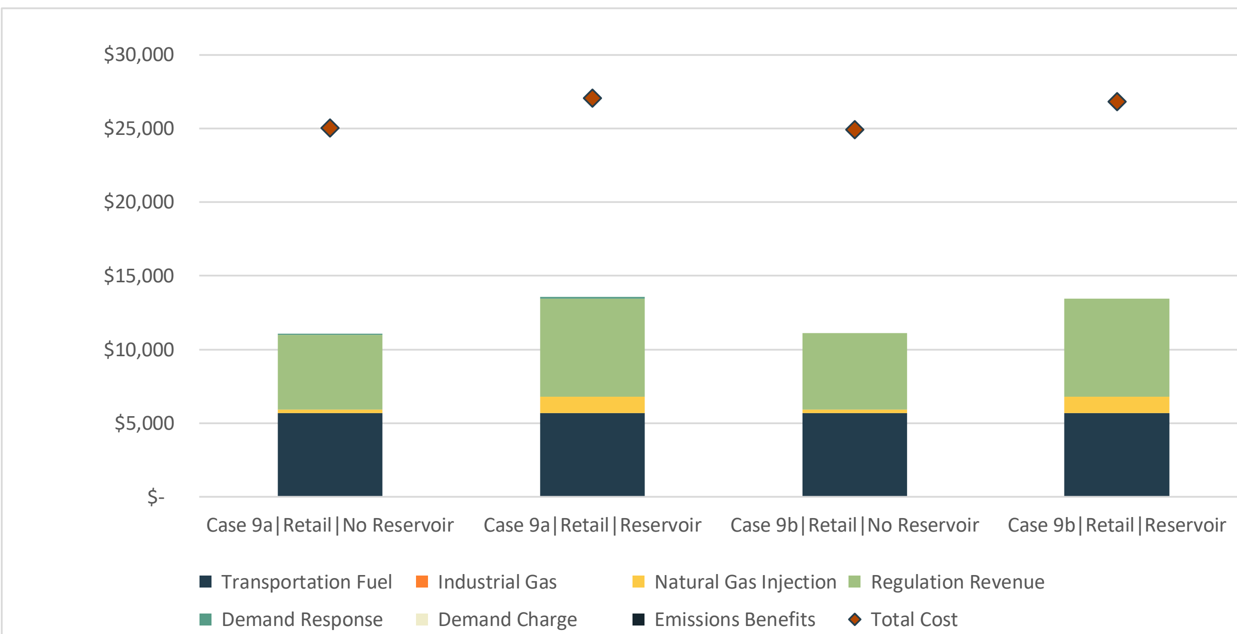


Figure 3.9. Economic Results for Case 9 – Base Case with Modified Operation as a Grid Asset ($Thousands)

3.10 Case 10 Results

Case 10 is a repeat of Case 3 (10a), Case 5b (triple demand for hydrogen as a transportation fuel) (10b), and Case 8a ($50/ton carbon tax) (10c) with one key difference: the P2G unit capacity is cut in half to 5 MW. This scenario recognizes that under the nine preceding cases, the P2G unit was operational in fewer than half of the available 8,760 hours each year and was, therefore, likely oversized based on the landscape of economic opportunity.

Under this case, the P2G unit operates 1,095–5,869 hours per year, generating 55–318 tons of hydrogen. Annualized revenue totals $0.6–$1.7 million, generating $7.4–$21.7 million in PV benefits over the 20-year economic life of the systems. When compared to total PV costs of $13.6–$21.6 million, Case 10 produces ROI ratios of 0.54–1.21. Case 10 results are presented in Table 3.11 and Figure 3.10.

The findings of this case clearly indicate that under the scenarios evaluated in this study, a 10 MW P2G system would be larger than needed based on the landscape of economic opportunity. Downsizing the P2G unit lowered capital costs considerable, resulting in a scenario (10c) yielding an ROI ratio exceeding 1.0.

Table 3.11. Detailed Economic Results – Case 10

Case	Transportation Fuel ($Thousands)	Natural Gas Injection ($Thousands)	Regulation Revenue ($Thousands)	Emissions Benefits ($Thousands)	Total Benefits ($Thousands)	Total Cost ($Thousands)	ROI	Hours of Operation	Hydrogen Production (tons)
Case 10a | RTM | No Reservoir	5,695	25	1,633	--	7,354	13,598	0.54	1096	55
Case 10a | RTM | Reservoir	5,695	1,381	2,666	--	9,742	15,778	0.62	2949	149
Case 10a | DAM | No Reservoir	5,695	20	2,381	--	8,096	14,071	0.58	1095	55
Case 10a | DAM | Reservoir	5,695	1,254	3,510	--	10,459	16,165	0.65	2792	140
Case 10b | RTM | No Reservoir	17,086	1	3,039	--	20,126	16,772	1.20	3092	157
Case 10b | RTM | Reservoir	17,086	528	3,340	--	20,955	17,552	1.19	3815	194
Case 10b | DAM | No Reservoir	17,086	1	4,076	--	21,163	17,502	1.21	3119	157
Case 10b | DAM | Reservoir	17,086	354	4,306	--	21,747	18,052	1.20	3613	181
Case 10c | RTM | No Reservoir	5,695	598	2,557	2,145	10,995	16,253	0.68	2950	149
Case 10c | RTM | Reservoir	5,695	3,767	4,130	4,606	18,199	21,557	0.84	5869	318
Case 10c | DAM | No Reservoir	5,695	519	3,381	1,971	11,567	16,615	0.70	2755	137
Case 10c | DAM | Reservoir	5,695	3,288	4,844	4,112	17,940	21,256	0.84	5489	284
Case 10d | RTM | No Reservoir	5,696	530	2,753	--	8,979	13,725	0.65	3041	152
Case 10d | RTM | Reservoir	5,695	2,772	3,003	--	11,470	14,808	0.77	4063	246
Case 10d | DAM | No Reservoir	5,696	524	3,320	--	9,540	13,979	0.68	3031	151
Case 10d | DAM | Reservoir	5,695	2,769	3,710	--	12,175	15,159	0.80	4062	245

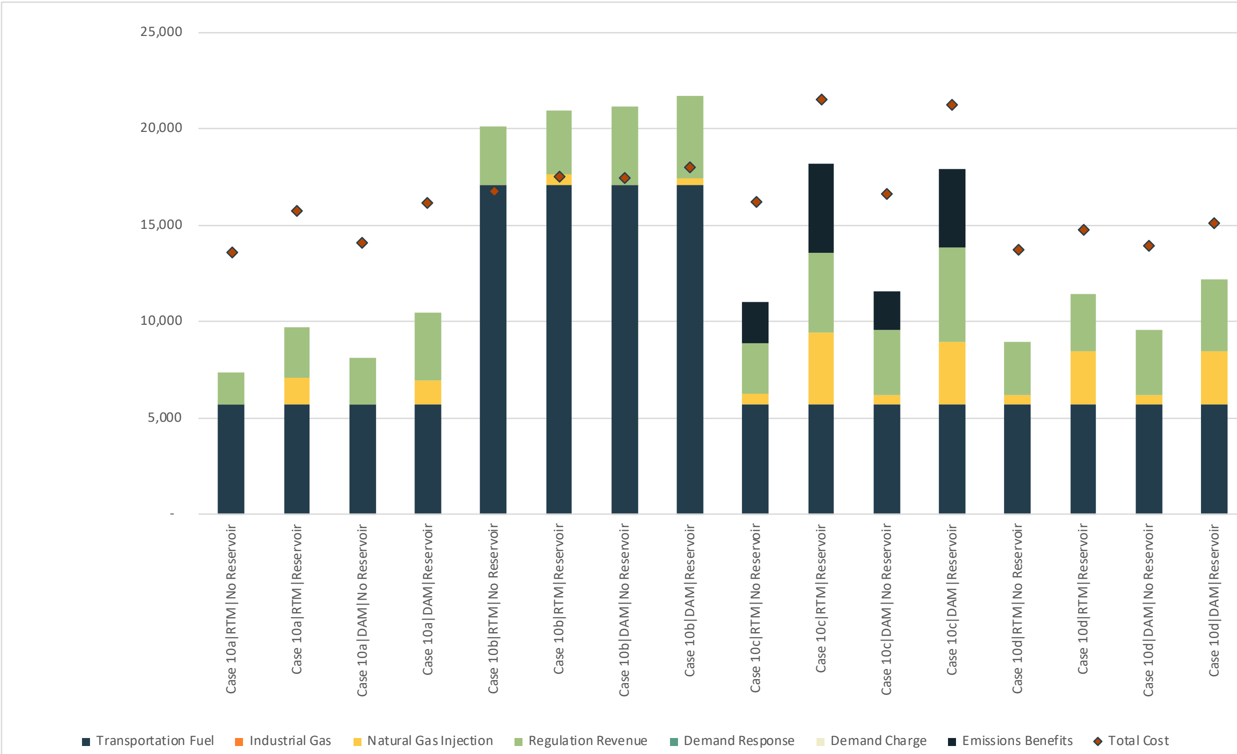


Figure 3.10. Economic Results for Case 10 – Cases 3, 5b, and 8a with a P2G Unit Capacity of 5 MW ($Thousands)

3.11 Case 11 Results

Case 11 assumes zero energy prices and emissions from March 19 to June 20 with a $50 carbon tax and double the transportation fuel demand. Under this case, the P2G unit operates 4,176–6,373 hours per year, generating 486–779 tons of hydrogen. Annualized revenue totals $2.0–$3.1 million, generating $26.7–$40.1 million in PV benefits over the 20-year economic life of the systems. When compared to total PV costs of $28.8–$36.2 million, Case 11 produces ROI ratios of 0.93–1.12. Case 11 results are presented in Table 3.12 and Figure 3.11.

Table 3.12. Detailed Economic Results – Case 11

Case	Transportation Fuel ($Thousands)	Natural Gas Injection ($Thousands)	Regulation Revenue ($Thousands)	Emissions Benefits ($Thousands)	Total Benefits ($Thousands)	Total Cost ($Thousands)	ROI	Hours of Operation	Hydrogen Production (tons)
Case 11 | RTM | No Reservoir	11,391	2,206	5,899	7,155	26,651	28,797	0.93	4,176	497
Case 11 | RTM | Reservoir	11,391	9,567	7,841	11,273	40,073	36,219	1.11	6,373	779
Case 11 | DAM | No Reservoir	11,391	2,119	7,254	7,007	27,772	29,368	0.95	4,155	486
Case 11 | DAM | Reservoir	11,391	8,963	8,867	10,642	39,863	35,672	1.12	6,079	736

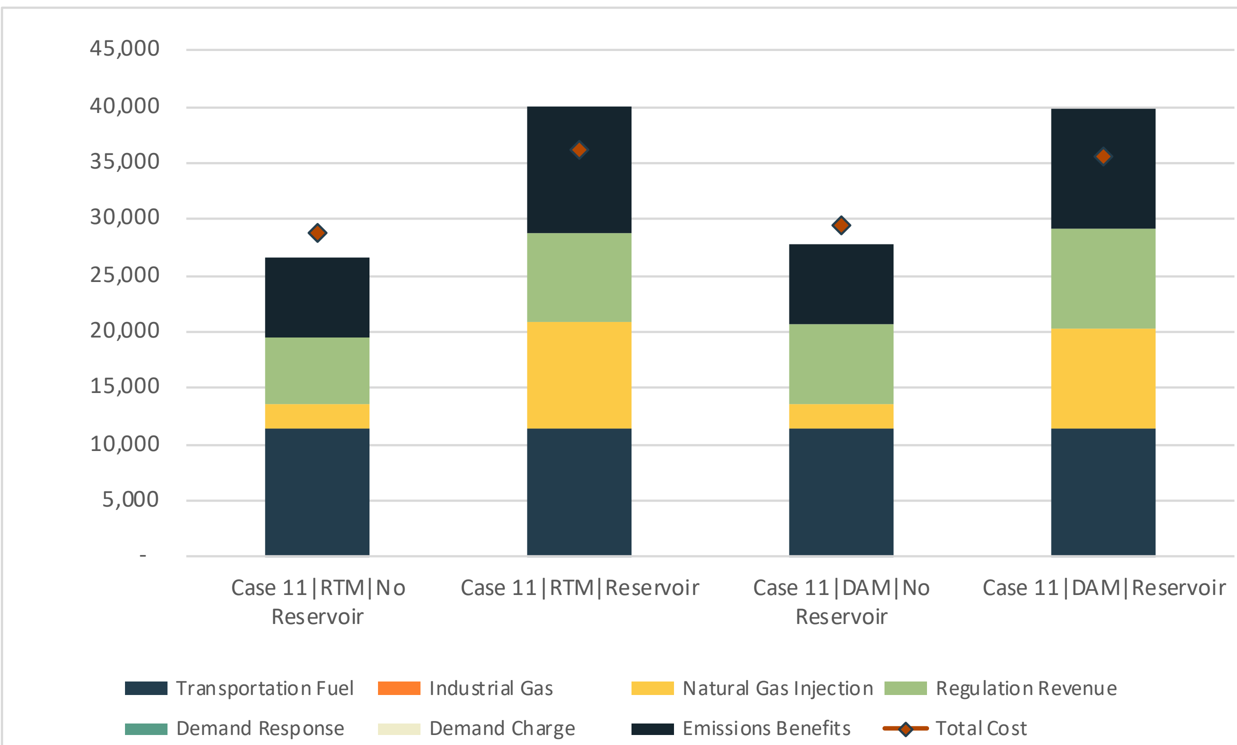


Figure 3.11. Economic Results for Case 11 – Zero Energy Prices and Emissions 3/19-6/20 with $50 Carbon Tax and Double Transportation Demand ($thousands)

4.0 Conclusions

This report presented all of the necessary methods and input information required to evaluate the financial benefits of a bundled set of use cases for P2G deployed in the HG&E system. Furthermore, the report defines the approach used to build a model flexible enough to be broadly applicable to other entities considering P2G in Massachusetts.

Based on the results presented in this report, the research team has drawn the following conclusions:

1. Of the 82 cases evaluated under this study, 76 yielded ROI ratios of under 1.0. Four of the cases generating ROI ratios in excess of 1.0 had lower costs because the capacity of the P2G unit was reduced to 5 MW, suggesting that the base system evaluated in this study at 10 MW was larger than optimal given the landscape of economic opportunity.
2. Results were most affected by demand for hydrogen as a transportation fuel. At $7/kg, the transportation sector represents the best economic opportunity for hydrogen revenue. Existing demand for hydrogen in and near Massachusetts to serve FCEVs is quite low at roughly 130 kg hydrogen per day, and there are currently no FCEV refueling stations in Massachusetts (Dillich 2014). At this stage in the FCEV hydrogen market on the East Coast, there is very little demand for the product; however, demand for hydrogen from FCEV users is projected to grow 4.65% annually in Massachusetts (Northeast Electrochemical Energy Storage Cluster 2018).
3. In the absence of cavern storage, methanation is required and injection into the natural gas pipeline generates very limited revenue. Even when allowing hydrogen admixture rates up to 5%, direct injection into the natural gas grid yields limited revenue. With depleted natural gas reservoir storage, as explored in this study, hydrogen can bypass the methanation process, thus lowering costs. Benefits are also higher under scenarios with reservoirs because the hydrogen can be stored seasonally to take advantage of higher natural gas prices during winter months when pipeline capacity is constrained and HG&E is paying higher prices for delivered LNG. With that noted, HG&E does not currently have any reservoir storage capacity.
4. Participation in the frequency regulation market improves project economics considerably by both generating revenue (up to $6.9 million in 20-year PV terms in the base case) and improving the value proposition for injection into the natural gas grid. Under scenarios with frequency regulation, revenue associated with natural gas grid injection is much higher because participation in the frequency regulation market effectively subsidizes production costs by providing the operator with a source of revenue obtained by varying production rates while following an AGC signal.
5. Clean energy incentives, while helpful in improving the value proposition for hydrogen, fail to cover all the ground necessary to make the P2G unit evaluated in this study profitable.

The tool that accompanied this report will enable users to evaluate future scenarios around changing technology cost and performance, clean energy prices, and market demand and prices. These future scenarios will enable the user to define the conditions under which hydrogen operation could be profitable in Massachusetts.

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Appendix A – Annualized and Present Value Costs and Benefits by Case

Case Type	Annualized Costs	Annualized Benefits	PV Costs	PV Benefits	ROI
Case 1 | RTM | No Reservoir	$1,645,751	$432,030	$21,482,217	$5,639,345	0.26
Case 1 | DAM | No Reservoir	$1,696,708	$433,543	$22,147,371	$5,659,092	0.26
Case 2 | RTM | No Reservoir	$1,653,038	$432,670	$21,577,334	$5,647,702	0.26
Case 2 | RTM | Reservoir	$1,690,083	$472,364	$22,060,897	$6,165,832	0.28
Case 2 | DAM | No Reservoir	$1,706,907	$433,341	$22,280,493	$5,656,462	0.25
Case 2 | DAM | Reservoir	$1,719,499	$440,387	$22,444,861	$5,748,435	0.26
Case 3 | RTM | No Reservoir	$1,774,273	$647,969	$23,159,834	$8,458,025	0.37
Case 3 | RTM | Reservoir	$2,158,041	$1,091,090	$28,169,208	$14,242,146	0.51
Case 3 | DAM | No Reservoir	$1,851,119	$756,635	$24,162,919	$9,876,469	0.41
Case 3 | DAM | Reservoir	$2,222,510	$1,205,122	$29,010,737	$15,730,630	0.54
Case 4a | RTM | No Reservoir	$1,963,299	$813,133	$25,627,222	$10,613,936	0.41
Case 4a | RTM | Reservoir	$2,278,770	$1,169,164	$29,745,106	$15,261,264	0.51
Case 4a | DAM | No Reservoir	$2,035,385	$925,893	$26,568,160	$12,085,811	0.45
Case 4a | DAM | Reservoir	$2,341,638	$1,281,383	$30,565,731	$16,726,070	0.55
Case 4b | RTM | No Reservoir	$1,969,505	$941,651	$25,708,220	$12,291,507	0.48
Case 4b | RTM | Reservoir	$2,284,910	$1,297,654	$29,825,246	$16,938,466	0.57
Case 4b | DAM | No Reservoir	$2,046,424	$1,060,115	$26,712,254	$13,837,824	0.52
Case 4b | DAM | Reservoir	$2,352,440	$1,415,604	$30,706,735	$18,478,075	0.60
Case 5a | RTM | No Reservoir	$1,872,244	$1,136,731	$24,438,657	$14,837,907	0.61
Case 5a | RTM | Reservoir	$2,187,627	$1,492,715	$28,555,407	$19,484,619	0.68
Case 5a | DAM | No Reservoir	$1,940,991	$1,247,148	$25,336,026	$16,279,193	0.64

Case Type	Annualized Costs	Annualized Benefits	PV Costs	PV Benefits	ROI
Case 5a | DAM | Reservoir	$2,246,888	$1,602,584	$29,328,947	$20,918,748	0.71
Case 5b | RTM | No Reservoir	$1,976,695	$1,624,357	$25,802,080	$21,202,960	0.82
Case 5b | RTM | Reservoir	$2,228,631	$1,902,191	$29,090,631	$24,829,569	0.85
Case 5b | DAM | No Reservoir	$2,050,977	$1,746,000	$26,771,695	$22,790,788	0.85
Case 5b | DAM | Reservoir	$2,289,681	$2,014,093	$29,887,527	$26,290,233	0.88
Case 5c | RTM | No Reservoir	$1,772,717	$459,410	$23,139,518	$5,996,738	0.26
Case 5c | RTM | Reservoir	$2,158,041	$904,093	$28,169,208	$11,801,248	0.42
Case 5c | DAM | No Reservoir	$1,855,695	$574,304	$24,222,643	$7,496,477	0.31
Case 5c | DAM | Reservoir	$2,222,510	$1,018,125	$29,010,737	$13,289,732	0.46
Case 5d | RTM | No Reservoir	$1,773,556	$834,036	$23,150,474	$10,886,790	0.47
Case 5d | RTM | Reservoir	$2,158,041	$1,278,087	$28,169,208	$16,683,044	0.59
Case 5d | DAM | No Reservoir	$1,856,129	$947,657	$24,228,315	$12,369,906	0.51
Case 5d | DAM | Reservoir	$2,222,510	$1,392,119	$29,010,737	$18,171,528	0.63
Case 6a | RTM | No Reservoir	$1,766,787	$653,253	$23,062,118	$8,527,003	0.37
Case 6a | RTM | Reservoir	$2,148,830	$1,091,090	$28,048,980	$14,242,146	0.51
Case 6a | DAM | No Reservoir	$1,858,384	$777,444	$24,257,744	$10,148,083	0.42
Case 6a | DAM | Reservoir	$2,213,300	$1,205,122	$28,890,510	$15,730,630	0.54
Case 6b | RTM | No Reservoir	$1,772,751	$661,518	$23,139,973	$8,634,891	0.37
Case 6b | RTM | Reservoir	$2,148,830	$1,091,090	$28,048,980	$14,242,146	0.51
Case 6b | DAM | No Reservoir	$1,867,818	$789,400	$24,380,893	$10,304,155	0.42
Case 6b | DAM | Reservoir	$2,213,300	$1,205,122	$28,890,510	$15,730,630	0.54
Case 6c | RTM | No Reservoir	$1,776,871	$667,100	$23,193,748	$8,707,743	0.38
Case 6c | RTM | Reservoir	$2,148,830	$1,091,090	$28,048,980	$14,242,146	0.51

Case Type	Annualized Costs	Annualized Benefits	PV Costs	PV Benefits	ROI
Case 6c | DAM | No Reservoir	$1,878,115	$801,385	$24,515,292	$10,460,597	0.43
Case 6c | DAM | Reservoir	$2,213,300	$1,205,122	$28,890,510	$15,730,630	0.54
Case 7 | RTM | No Reservoir	$1,810,071	$905,725	$23,627,110	$11,822,554	0.50
Case 7 | RTM | Reservoir	$2,013,388	$1,358,823	$26,281,039	$17,736,905	0.67
Case 7 | DAM | No Reservoir	$1,861,545	$997,747	$24,299,004	$13,023,726	0.54
Case 7 | DAM | Reservoir	$2,071,657	$1,470,664	$27,041,625	$19,196,789	0.71
Case 8a | RTM | No Reservoir	$2,249,205	$1,251,557	$29,359,191	$16,336,743	0.56
Case 8a | RTM | Reservoir	$3,058,969	$2,398,962	$39,929,155	$31,313,981	0.78
Case 8a | DAM | No Reservoir	$2,305,587	$1,339,620	$30,095,151	$17,486,244	0.58
Case 8a | DAM | Reservoir	$3,013,905	$2,359,274	$39,340,918	$30,795,928	0.78
Case 8b | RTM | No Reservoir	$1,773,556	$802,870	$23,150,474	$10,479,974	0.45
Case 8b | RTM | Reservoir	$2,158,041	$1,246,920	$28,169,208	$16,276,228	0.58
Case 8b | DAM | No Reservoir	$1,854,699	$915,996	$24,209,641	$11,956,624	0.49
Case 8b | DAM | Reservoir	$2,222,510	$1,360,953	$29,010,737	$17,764,712	0.61
Case 9a | Retail | No Reservoir	$1,916,718	$842,550	$25,019,187	$11,069,742	0.44
Case 9a | Retail | Reservoir	$2,072,063	$1,029,620	$27,046,925	$13,588,430	0.50
Case 9b | Retail | No Reservoir	$1,909,969	$850,948	$24,931,098	$11,107,538	0.45
Case 9b | Retail | Reservoir	$2,055,063	$1,031,779	$26,825,030	$13,467,950	0.50
Case 10a | RTM | No Reservoir	$1,041,729	$563,360	$13,597,831	$7,353,622	0.54
Case 10a | RTM | Reservoir	$1,208,788	$746,358	$15,778,485	$9,742,310	0.62
Case 10a | DAM | No Reservoir	$1,078,007	$620,237	$14,071,372	$8,096,043	0.58
Case 10a | DAM | Reservoir	$1,238,419	$801,292	$16,165,254	$10,459,374	0.65
Case 10b | RTM | No Reservoir	$1,284,876	$1,541,880	$16,771,672	$20,126,372	1.20

Case Type	Annualized Costs	Annualized Benefits	PV Costs	PV Benefits	ROI
Case 10b | RTM | Reservoir	$1,344,642	$1,605,329	$17,551,803	$20,954,583	1.19
Case 10b | DAM | No Reservoir	$1,340,806	$1,621,329	$17,501,724	$21,163,428	1.21
Case 10b | DAM | Reservoir	$1,382,962	$1,666,021	$18,052,001	$21,746,803	1.20
Case 10c | RTM | No Reservoir	$1,245,149	$842,358	$16,253,106	$10,995,412	0.68
Case 10c | RTM | Reservoir	$1,651,478	$1,394,207	$21,556,968	$18,198,783	0.84
Case 10c | DAM | No Reservoir	$1,272,873	$886,127	$16,614,993	$11,566,744	0.70
Case 10c | DAM | Reservoir	$1,628,382	$1,374,347	$21,255,501	$17,939,539	0.84
Case 10d | RTM | No Reservoir	$1,051,439	$687,862	$13,724,580	$8,978,763	0.65
Case 10d | RTM | Reservoir	$1,134,459	$878,716	$14,808,255	$11,470,000	0.77
Case 10d | DAM | No Reservoir	$1,070,947	$730,854	$13,979,219	$9,539,936	0.68
Case 10d | DAM | Reservoir	$1,161,307	$932,719	$15,158,698	$12,174,911	0.80
Case 11 | RTM | No Reservoir	$2,206,173	$2,041,748	$28,797,488	$26,651,218	0.93
Case 11 | RTM | Reservoir	$2,774,755	$3,069,955	$36,219,272	$40,072,552	1.11
Case 11 | DAM | No Reservoir	$2,249,872	$2,127,574	$29,367,897	$27,771,525	0.95
Case 11 | DAM | Reservoir	$2,732,838	$3,053,871	$35,672,122	$39,862,602	1.12

Appendix B – Benefit Breakdown by Case ($thousands)

Case	Transportation Fuel	Industrial Gas	Natural Gas Injection	Regulation Revenue	Demand Response	Demand Charge	Emissions Benefits	Total Benefits
Case 1 | RTM | No Reservoir	$5,639	$-	$-	$-	$-	$-	$-	$5,639
Case 1 | DAM | No Reservoir	$5,659	$-	$-	$-	$-	$-	$-	$5,659
Case 2 | RTM | No Reservoir	$5,640	$-	$7	$-	$-	$-	$-	$5,648
Case 2 | RTM | Reservoir	$5,641	$-	$525	$-	$-	$-	$-	$6,166
Case 2 | DAM | No Reservoir	$5,656	$-	$-	$-	$-	$-	$-	$5,656
Case 2 | DAM | Reservoir	$5,659	$-	$89	$-	$-	$-	$-	$5,748
Case 3 | RTM | No Reservoir	$5,695	$-	$174	$2,588	$-	$-	$-	$8,458
Case 3 | RTM | Reservoir	$5,695	$-	$3,411	$5,135	$-	$-	$-	$14,242
Case 3 | DAM | No Reservoir	$5,695	$-	$173	$4,008	$-	$-	$-	$9,876
Case 3 | DAM | Reservoir	$5,695	$-	$3,173	$6,862	$-	$-	$-	$15,731
Case 4a|RTM|No Reservoir	$5,695	$1,594	$75	$3,249	$-	$-	$-	$10,614
Case 4a|RTM|Reservoir	$5,695	$1,596	$2,762	$5,208	$-	$-	$-	$15,261
Case 4a|DAM|No Reservoir	$5,695	$1,589	$60	$4,741	$-	$-	$-	$12,086
Case 4a | DAM | Reservoir	$5,695	$1,595	$2,508	$6,928	$-	$-	$-	$16,726
Case 4b | RTM | No Reservoir	$5,696	$3,216	$75	$3,304	$-	$-	$-	$12,292
Case 4b | RTM | Reservoir	$5,696	$3,217	$2,762	$5,263	$-	$-	$-	$16,938
Case 4b | DAM | No Reservoir	$5,696	$3,252	$60	$4,830	$-	$-	$-	$13,838
Case 4b | DAM | Reservoir	$5,696	$3,254	$2,508	$7,020	$-	$-	$-	$18,478
Case 5a | RTM | No Reservoir	$11,391	$-	$75	$3,372	$-	$-	$-	$14,838
Case 5a | RTM | Reservoir	$11,391	$-	$2,762	$5,331	$-	$-	$-	$19,485

Case	Transportation Fuel	Industrial Gas	Natural Gas Injection	Regulation Revenue	Demand Response	Demand Charge	Emissions Benefits	Total Benefits
Case 5a | DAM | No Reservoir	$11,391	$-	$60	$4,828	$-	$-	$-	$16,279
Case 5a | DAM | Reservoir	$11,391	$-	$2,508	$7,020	$-	$-	$-	$20,919
Case 5b | RTM | No Reservoir	$17,086	$-	$22	$4,094	$-	$-	$-	$21,203
Case 5b | RTM | Reservoir	$17,086	$-	$2,198	$5,545	$-	$-	$-	$24,830
Case 5b | DAM | No Reservoir	$17,086	$-	$16	$5,688	$-	$-	$-	$22,791
Case 5b |DAM | Reservoir	$17,086	$-	$1,934	$7,270	$-	$-	$-	$26,290
Case 5c | RTM | No Reservoir	$3,255	$-	$174	$2,568	$-	$-	$-	$5,997
Case 5c | RTM | Reservoir	$3,255	$-	$3,411	$5,135	$-	$-	$-	$11,801
Case 5c | DAM | No Reservoir	$3,255	$-	$183	$4,059	$-	$-	$-	$7,496
Case 5c | DAM | Reservoir	$3,255	$-	$3,173	$6,862	$-	$-	$-	$13,290
Case 5d | RTM | No Reservoir	$8,136	$-	$176	$2,575	$-	$-	$-	$10,887
Case 5d | RTM | Reservoir	$8,136	$-	$3,411	$5,135	$-	$-	$-	$16,683
Case 5d | DAM | No Reservoir	$8,137	$-	$186	$4,047	$-	$-	$-	$12,370
Case 5d | DAM | Reservoir	$8,136	$-	$3,173	$6,862	$-	$-	$-	$18,172
Case 6a | RTM | No Reservoir	$5,695	$-	$214	$2,618	$-	$-	$-	$8,527
Case 6a | RTM | Reservoir	$5,695	$-	$3,411	$5,135	$-	$-	$-	$14,242
Case 6a | DAM | No Reservoir	$5,695	$-	$241	$4,211	$-	$-	$-	$10,148
Case 6a | DAM | Reservoir	$5,695	$-	$3,173	$6,862	$-	$-	$-	$15,731
Case 6b | RTM | No Reservoir	$5,695	$-	$258	$2,681	$-	$-	$-	$8,635
Case 6b | RTM | Reservoir	$5,695	$-	$3,411	$5,135	$-	$-	$-	$14,242
Case 6b | DAM | No Reservoir	$5,695	$-	$298	$4,311	$-	$-	$-	$10,304

Case	Transportation Fuel	Industrial Gas	Natural Gas Injection	Regulation Revenue	Demand Response	Demand Charge	Emissions Benefits	Total Benefits
Case 6b | DAM | Reservoir	$5,695	$-	$3,173	$6,862	$-	$-	$-	$15,731
Case 6c | RTM | No Reservoir	$5,695	$-	$285	$2,727	$-	$-	$-	$8,708
Case 6c | RTM | Reservoir	$5,695	$-	$3,411	$5,135	$-	$-	$-	$14,242
Case 6c | DAM | No Reservoir	$5,695	$-	$351	$4,414	$-	$-	$-	$10,461
Case 6c | DAM | Reservoir	$5,695	$-	$3,173	$6,862	$-	$-	$-	$15,731
Case 7 | RTM | No Reservoir	$5,695	$-	$1,217	$4,910	$-	$-	$-	$11,823
Case 7 | RTM | Reservoir	$5,695	$-	$6,216	$5,826	$-	$-	$-	$17,737
Case 7 | DAM | No Reservoir	$5,696	$-	$1,235	$6,093	$-	$-	$-	$13,024
Case 7 | DAM | Reservoir	$5,695	$-	$6,231	$7,271	$-	$-	$-	$19,197
Case 8a | RTM | No Reservoir	$5,695	$-	$1,462	$4,959	$-	$-	$4,220	$16,337
Case 8a | RTM | Reservoir	$5,695	$-	$8,259	$8,158	$-	$-	$9,201	$31,314
Case 8a | DAM | No Reservoir	$5,695	$-	$1,308	$6,603	$-	$-	$3,879	$17,486
Case 8a | DAM | Reservoir	$5,695	$-	$7,303	$9,585	$-	$-	$8,213	$30,796
Case 8b | RTM | No Reservoir	$7,730	$-	$176	$2,575	$-	$-	$-	$10,480
Case 8b | RTM | Reservoir	$7,730	$-	$3,411	$5,135	$-	$-	$-	$16,276
Case 8b | DAM | No Reservoir	$7,730	$-	$183	$4,044	$-	$-	$-	$11,957
Case 8b | DAM | Reservoir	$7,730	$-	$3,173	$6,862	$-	$-	$-	$17,765
Case 9a | Retail | No Reservoir	$5,696	$-	$215	$5,087	$72	$-	$-	$11,070
Case 9a | Retail | Reservoir	$5,696	$-	$1,121	$6,623	$149	$-	$-	$13,588
Case 9b | Retail | No Reservoir	$5,696	$-	$214	$5,197	$-	$-	$-	$11,108
Case 9b | Retail | Reservoir	$5,696	$-	$1,097	$6,675	$-	$-	$-	$13,468

Case	Transportation Fuel	Industrial Gas	Natural Gas Injection	Regulation Revenue	Demand Response	Demand Charge	Emissions Benefits	Total Benefits
Case 10a | RTM | No Reservoir	$5,695	$-	$25	$1,633	$-	$-	$-	$7,354
Case 10a | RTM | Reservoir	$5,695	$-	$1,381	$2,666	$-	$-	$-	$9,742
Case 10a | DAM | No Reservoir	$5,695	$-	$20	$2,381	$-	$-	$-	$8,096
Case 10a | DAM | Reservoir	$5,695	$-	$1,254	$3,510	$-	$-	$-	$10,459
Case 10b | RTM | No Reservoir	$17,086	$-	$1	$3,039	$-	$-	$-	$20,126
Case 10b | RTM | Reservoir	$17,086	$-	$528	$3,340	$-	$-	$-	$20,955
Case 10b | DAM | No Reservoir	$17,086	$-	$1	$4,076	$-	$-	$-	$21,163
Case 10b | DAM | Reservoir	$17,086	$-	$354	$4,306	$-	$-	$-	$21,747
Case 10c | RTM | No Reservoir	$5,695	$-	$598	$2,557	$-	$-	$2,145	$10,995
Case 10c | RTM | Reservoir	$5,695	$-	$3,767	$4,130	$-	$-	$4,606	$18,199
Case 10c | DAM | No Reservoir	$5,695	$-	$519	$3,381	$-	$-	$1,971	$11,567
Case 10c | DAM | Reservoir	$5,695	$-	$3,288	$4,844	$-	$-	$4,112	$17,940
Case 10d | RTM | No Reservoir	$5,696	$-	$530	$2,753	$-	$-	$-	$8,979
Case 10d | RTM | Reservoir	$5,695	$-	$2,772	$3,003	$-	$-	$-	$11,470
Case 10d | DAM | No Reservoir	$5,696	$-	$524	$3,320	$-	$-	$-	$9,540
Case 10d | DAM | Reservoir	$5,695	$-	$2,769	$3,710	$-	$-	$-	$12,175
Case 11 | RTM | No Reservoir	$11,391	$-	$2,206	$5,899	$-	$-	$7,155	$26,651
Case 11 | RTM | Reservoir	$11,391	$-	$9,567	$7,841	$-	$-	$11,273	$40,073
Case 11 | DAM | No Reservoir	$11,391	$-	$2,119	$7,254	$-	$-	$7,007	$27,772
Case 11 | DAM | Reservoir	$11,391	$-	$8,963	$8,867	$-	$-	$10,642	$39,863

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