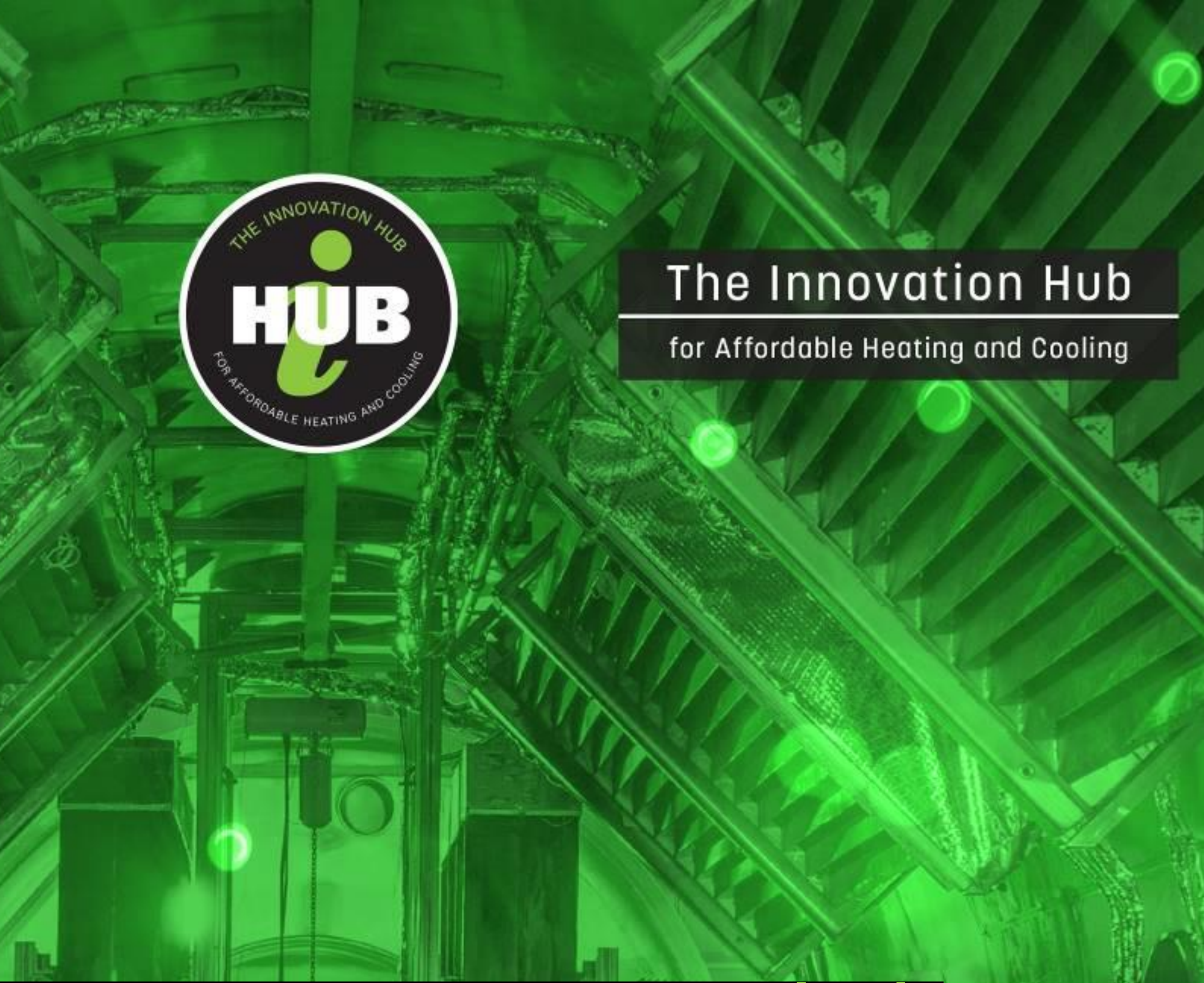

The Innovation Hub

for Affordable Heating and Cooling

Sub-Project Technical Report – DCH3

Precinct energy integration for accessing the wholesale demand response mechanism

DCH3

8th June, 2022

DeltaQ Pty Ltd

About i-Hub

The Innovation Hub for Affordable Heating and Cooling (i-Hub) is an initiative led by the Australian Institute of Refrigeration, Air Conditioning and Heating (AIRAH) in conjunction with CSIRO, Queensland University of Technology (QUT), the University of Melbourne and the University of Wollongong and supported by Australian Renewable Energy Agency (ARENA) to facilitate the heating, ventilation, air conditioning and refrigeration (HVAC&R) industry's transition to a low emissions future, stimulate jobs growth, and showcase HVAC&R innovation in buildings.

The objective of i-Hub is to support the broader HVAC&R industry with knowledge dissemination, skills-development and capacity-building. By facilitating a collaborative approach to innovation, i-Hub brings together leading universities, researchers, consultants, building owners and equipment manufacturers to create a connected research and development community in Australia.

This Project received funding from ARENA as part of ARENA's Advancing Renewables Program.
The views expressed herein are not necessarily the views of the Australian Government, and the Australian Government does not accept responsibility for any information or advice contained herein.

Precinct Energy Integration for Accessing the Wholesale Demand Response Mechanism

The project assessed the feasibility of potentially using significant resource availability of existing, under-utilised gas-fired generators to assist in managing the site and grid level impacts of the variability of renewable generation. It seeks to understand how existing gas-fired generation assets can operate in sync with on-site energy consumption and renewable generation to maximise life-cycle and environmental benefits while also providing useful support service to the grid. The project uses data from an office precinct in Melbourne CBD, which has an operational gas-fired generation and renewable energy generation capabilities. The i-HUB/CSIRO developed Data Clearing House was also utilised, and it provided the opportunity to integrate diverse data sources across multiple buildings and discrete systems. As part of this project, the business case of using existing has engines as a demand response resource was assessed, strategies for operating the gas generators are provided, and a set of guidelines to assist other sites was developed.

Lead organisation

DeltaQ Pty Ltd

Project commencement date

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Contact name

Caoimhin Ardren - DeltaQ

Email

caoimhin.ardren@dqcs.com.au

Project website

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EXECUTIVE SUMMARY

Between 2000 and 2015, many commercial buildings installed cogeneration and trigeneration systems, most of which are now underutilised or no longer in use. This project set out to explore methods of using these high embodied energy assets from the perspective of maximising the product's life-cycle and potentially leveraging the demand response market to both access an alternative revenue stream and provide grid support services.

This sub-project, DCH3, is focussed on the potential to operate existing, underutilised, gas-fired generation assets in sync with on-site renewable generation and consumption and to provide useful support services to the grid. A combination of methods was used in the investigation, including: a review of the installed cogeneration and trigeneration capacity, analysis of electricity market data, analysis of data from a pilot study site, and finally consultation with third parties that enable end-users to participate in demand response programs. Details and results of the investigation completed as part of this project are reported here.

Key findings include:

- Operation of gas generators for demand management is best considered by sites with generators that are not currently operated to meet the underlying site demand.
- Operation of the heat recovery systems and co/trigen units is a minor consideration in the economics of using gas generators for demand management due to a combination of slow thermal response times and the sporadicity of demand response events. In general therefore these systems should not be enabled in this context.
- When using gas generators to participate in grid-level events, participation through a 3rd party who is a registered market participant is the most feasible/practical method for building owners. Revenue can be obtained from being committed to and participating in RERT events and wholesale demand response programs. Due to the high operating and maintenance costs for generators, participation in both programs and any other demand management revenue streams is recommended, in view of achieving a positive financial return.
- If gas generators are used to respond to changes in on-site renewable energy fluctuations, it is necessary for peak demand charges to be successfully avoided and for the generator to be used at maximum capacity in order to achieve a positive financial return.
- In general, the net real-time environmental impact of gas generator operation leads to more real-time greenhouse gas emissions, with site-to-site variations associated with differences in geographic location and generator efficiencies. However, the impact on NABERS ratings is generally positive due to the annualised (and out-of-date) greenhouse gas coefficients used. Negative site-level impacts however have to be weighed against the potential increase in renewable generation capacity in the grid enabled by the presence of increased demand management resources.

1 INTRODUCTION

1.1 Overview and Objectives

In the period 2000-2015, many office building developments installed cogeneration or trigeneration systems to reduce the use of carbon-intensive grid electricity. However, many of these systems have since been mothballed or under-utilised. Consequently, there is an opportunity to determine if these high-embodied energy assets can be utilised in ways where they can create a net benefit – both financially and environmentally.

The under-utilisation of existing co/tri-gen systems can be attributed to multiple factors, including poor matching of generator size to site load, increasing gas prices, high maintenance costs and the progressive decarbonisation of the electricity grid. With the latter, it is expected that gas-fired systems will no longer provide an emissions benefit as the grid is decarbonised in the near future.

Since 2015, the quantity of renewable energy generation in the electricity grid has increased significantly, and many buildings have installed on-site PV arrays. Due to variations in on-site generation, the site demand can vary considerably, which may impact the electricity grid. These factors combine to create a requirement at both site and grid levels for a demand response mechanism to smooth out variability.

This project explored using under-utilised gas generators (cogen and trigen systems) as the demand response mechanism. The findings are intended to inform how these generators can be operated to complement on-site and grid-connected renewable energy generation, support the electricity grid stability, and thereby facilitate the maximisation amount of renewable energy generation in the grid overall.

The primary objectives for this project were to:

- Develop a strategy for operating existing under-utilised cogeneration/trigeneration gas engines as demand response units in response to short-term changes in on-site renewable generation output and to respond to demand response events in the electricity market
- Analyse the business case for such operations.
- Provide guidelines and information to assist other similar sites to achieve positive outcomes.

1.2 Boundaries and Limitations

This project focused on existing gas-fired generators that have been installed in commercial buildings. The assessment of success was limited to an operational case where the gas generators are used solely for demand management rather than as generators that are operated to supply a site's base load. This is because sites that currently run co/trigen systems are placing a smaller demand on the electricity grid, hence their opportunity to reduce demand is minimal. The focus on underutilised gas generators also aligns with the potential opportunity created by the increase in number of commercial building sites looking to decommission their cogeneration and trigeneration systems.

This analysis assumes that there are no changes to the site's operation during the demand response events; i.e. all other aspects of the building's operations are unchanged; thereby ensuring that the change in the site's grid electricity demand is solely based on substituting a portion of grid electricity consumption with electricity generated by the generator.

The assessment also excludes the option of operating the gas generators to export into the grid.

This report details the methods, values, statistics, and values which are available to the public, along with their source. Values not reported on or otherwise not specified are commercial in confidence. In such cases, aggregated results are presented.

2 BACKGROUND

2.1 An Overview of Cogeneration and Trigeneration Systems

Cogeneration and trigeneration plants in buildings convert a fuel source (most commonly natural gas) to electricity. The waste heat generated from the combustion process is typically used for space heating (cogeneration) and absorption chiller cooling (trigeneration). Figure 1 depicts the key features of each system. The two most common generator types that have been installed in commercial buildings are reciprocating engines and microturbines (1,2). The typical range of generator size, maximum design ramp rates (i.e. speed to load or unload) and electrical efficiencies are summarised in Table 1 below (1–9).

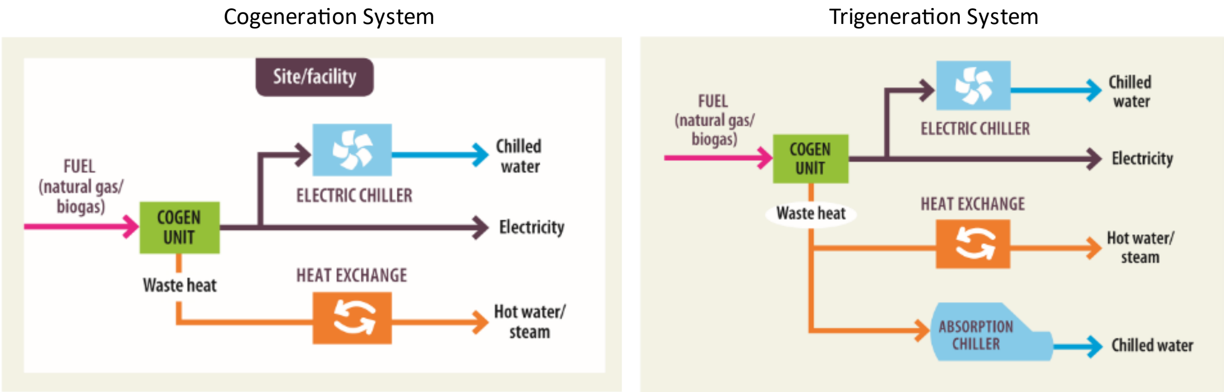


Figure 1: Cogeneration and Trigeneration System (reproduced from (1))

Table 1: Summary of common co/trigen generator types in commercial buildings, and their characteristics (1–9).

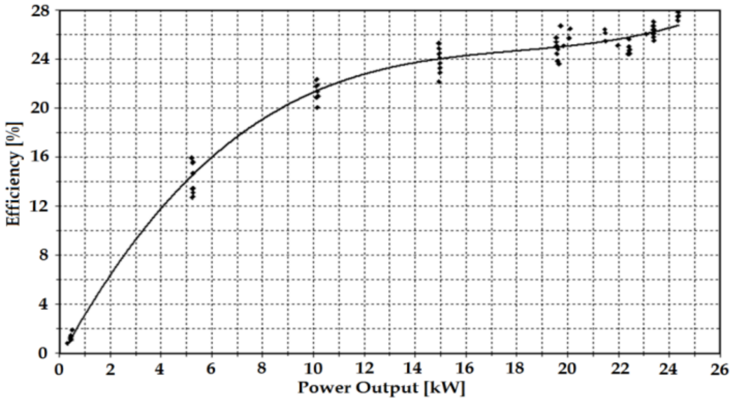
Generator Type	Typical Size	Typical Ramp Rates (relative to maximum output power)	Typical Electrical Efficiency (Natural Gas)
Reciprocating Engines	20 – 4000 kW (1)	20 -50% /min (2–4)	20 - 40% (2,5,6)
Microturbines	30 – 250 kW (1)	Up to 60%/ min [1]	15 – 30%[2] (7–9)

The efficiency of the cogeneration and trigeneration plants and amount of gas consumed is dependent on the electrical generation efficiency of the generators used. The electrical efficiency of the generators varies depending on the load. Figure 2 shows the electrical efficiency of a microturbine at part loads, with a clear trend of increasing efficiency as the power output increases. As depicted, microturbines provide the best performance at, or near, full

[1] Based on actual building data observations

[2] 15% for unrecuperated technologies, 20-30% for recuperated technologies.

load. Reciprocating engines have a higher partial load efficiency profile, compared to microturbines (10), but are limited in the extent to which they can be turn down to match the required load.



27% efficiency is possible at full load, 30 kW full load output power. Reproduced from (7)

Figure 2: Microturbine (Capstone 330 High Pressure) efficiency at part load.

Natural gas is the primary fuel source for cogeneration and trigeneration systems in commercial buildings. Many of these systems were installed to provide electricity with a lower emissions source compared to grid electricity. However, this intended benefit has diminished with the gradual decarbonisation of grid electricity. Using bio-gas instead of natural gas to fuel these generators is an option that provides an opportunity to reduce the emissions associated with operating co/trigeneration systems. However, switching from natural gas to bio-gas increases gas consumption (volume), since bio-gas tends to have a lower energy content (MJ/m^3) (11,12), and slightly reduce the electrical and thermal recovery efficiencies of the system (typically by less than 2%) (5,6,12).

Another consideration for co/trigen systems worth noting is the start-up sequence and duration of operation directly affects the ability of the generator to respond to demand fluctuations. The time between a generator receiving a signal and having a power output can be in the order of one to several minutes. For example, Jenbacher Type 2 and 3 gas engines are capable of ramping to 100% of their power output within 70 seconds of receiving the request to start up (4), while Capstone microturbines can start-up within 90 seconds[3].

2.2 Cogeneration/trigeneration Installed and Potential Demand Response Capacity

While the installation of cogeneration and trigeneration units in commercial buildings (and other locations such as recreation and aquatic centres) peaked between 2010 – 2015, the extent of remaining operable gas generators is not well documented. In Australia, at least 120 MW of cogeneration and trigeneration capacity has been installed in the buildings (commercial, office towers, retail and residential), hospitals, and recreational facilities and precincts[4]. In the built environment, the largest generation capacities are likely to be in hospitals, followed by data centres, airports, and office buildings[5]. However, the status of these installations varies widely (Figure 3) and include:

- Currently used regularly to services part of the base building loads
- Operational but used sporadically

[3] Determined from existing building operational data.
[4] Based on a compilations of publicly available and confidential sourced information
[5] The installed capacity of cogeneration and trigeneration, for hospitals, data centres, airports and office buildings are at least 50 MW, 38 MW, 29MW identified, and 28MW, respectively.

- Not currently used. It is unknown whether these can be safely fired up as a demand response unit. It is understood that some of the engines have been dormant for too long, with additional repairs required to be operational.
- Has been switched off, decommissioned, or removed (13)[6]

Operational	Earmarked for decommissioning	Not Operational
•Systems currently used to support building base loads •Systems that are operating, albeit sopradically (e.g. as not scheduled generation units)	•Systems that are currently operating but earmarked to be decomissioned.	•System Decomissioned •System has not been used in a while and/or requires the additional repairs for it to be operating

Figure 3: Operational states of existing cogeneration and trigeneration assets

Operating the cogeneration or trigeneration system for demand response is limited to gas generators that are currently in an operational state. The financial feasibility of operating for the purpose of demand response is heavily dependent on the operation and maintenance cost of the system (further details are provided in subsequent sections). Any additional cost incurred to repair currently inoperable generators will likely result in a poor business case.

It is expected that the available capacity of cogeneration or trigeneration systems will continue to decline. As a result, it will require speedy intervention if use is to be made of the remaining generators for demand response.

2.3 Demand Response Events

The two basic categories of demand response are: 1) site electricity demand, and 2) grid demand events

2.3.1 Site Electricity Demand

A site's demand for grid electricity varies depending on the operation of the building, and changes to renewable energy generated on-site, if installed. Gas generators from the cogeneration or trigeneration units can be used to minimise peak demand charges arising from consumption of grid electricity at peak times or from sudden fluctuations in building demand arising from short-term reductions in on-site PV generation (i.e. when the sun goes behind a cloud).

2.3.2 Grid Demand Events

Grid demand events occur when there is a grid-level shortfall in generation relative to the load, either because of excessive demand or because of short-term deficiencies of generation. There are several different types of grid demand events, as summarised in Table 2.

[6] Based off AEMO's NEM generation list (13).

Table 2: Types of grid demand events and suitability for gas-fired generators to respond to them.

Grid Demand Events	Description	Expected Event Frequency, Duration and Response Time†	Suitability for gas-fired generators
Reliability and Emergency Reserve Trader (RERT)	The Reliability and Emergency Reserve Trader events are signalled by a forecasted shortfall in energy reserves, typically when there's a combination of hot/ extreme weather, high demand, generation or transmission outages. RERT events are enacted by AEMO and are infrequent.	Frequency: Low (1 – 3 times a year) Duration: 3 – 6 hours Response time: <120 mins	Y
Wholesale Demand Response (WDR)	These are events that are signalled by a spike in the spot price of electricity. These are typically based on the Wholesale Demand Response Mechanism (WDRM).	Frequency: Moderate (5 – 20 times per year) Duration: Variable, depending on settings selected by the demand responder. Response time: < 30 mins	Y
Frequency Control Ancillary Services (FCAS)	These are events that are signalled by a frequency outside the preferred control range and are fast response events of short duration (10mins or less).	Frequency: High (1-3 times per month)(14) Duration: 10 mins or less Response time: 6 sec, 60 sec, or 5 mins	N*

Notes:
† Frequencies may varies depending on the location (State). Based on a collation of values published and review of market rules and events (14–16).
* Due to these characteristics, they are less suited for generator response and have not been considered further

The operation of gas generators as demand response units is better suited to Reliability and Emergency Reserve Trader (RERT) and Wholesale Demand Response (WDR) events than to Frequency Control Ancillary Services (FCAS) events. Differences in suitability arise from each type of event/scheme having specific requirement such as the (rapid) response times for the FCAS or the longer curtailment times for the RERT.

- FCAS events - participation in these events is largely dictated by the tight response times; typically gas generators would only meet the delayed raise/lower events (5min response times) as they can require approximately 70 - 90s to start up and achieve maximum power output (4).

- Reliability and Reserve Energy Trader (RERT), is a scheme administered by AEMO to ensure reliable access and supply of electricity during predicted periods of electricity shortfall. The RERT incentivises large reserves[7] to increase generation or reduce electrical demand during these high demand periods. Figure 4(a) provides an overview of the RERT events that were activated, showing the start time (typically occurring around 4 pm), and duration of each event. It should be noted that in Figure 4(a), the activation of RERT across different states on the same day are presented as separately (one per state). Between July 2021 and June 2022, AEMO activated five RERT events (two in Queensland, three in New South Wales) (17); indicating that the RERT

[7] From AEMO's perspective, not less than 10 MW. Sites with capacities lower than 10MW can still participate through a third party.

demand response events are both infrequent and long in duration. Participation in RERT events will likely require sites to curtail their loads for between 3 to 6 hours.

- The Wholesale Demand Response Mechanism (WDRM) is relatively new and was introduced by AEMO in October 2021. It incentivises electricity consumers to participate in the wholesale market by receiving payment related to their load curtailment (measured against a baseline), at the electricity spot price. While the mechanism permits participation in the market at any time, participation at time of high electricity prices and electricity supply scarcity is most likely. Since October 2021, when the WDRM came into effect, until April 2022, wholesale demand response units have been dispatched twice[8]. The start times and end times are shown in Figure 4(b).

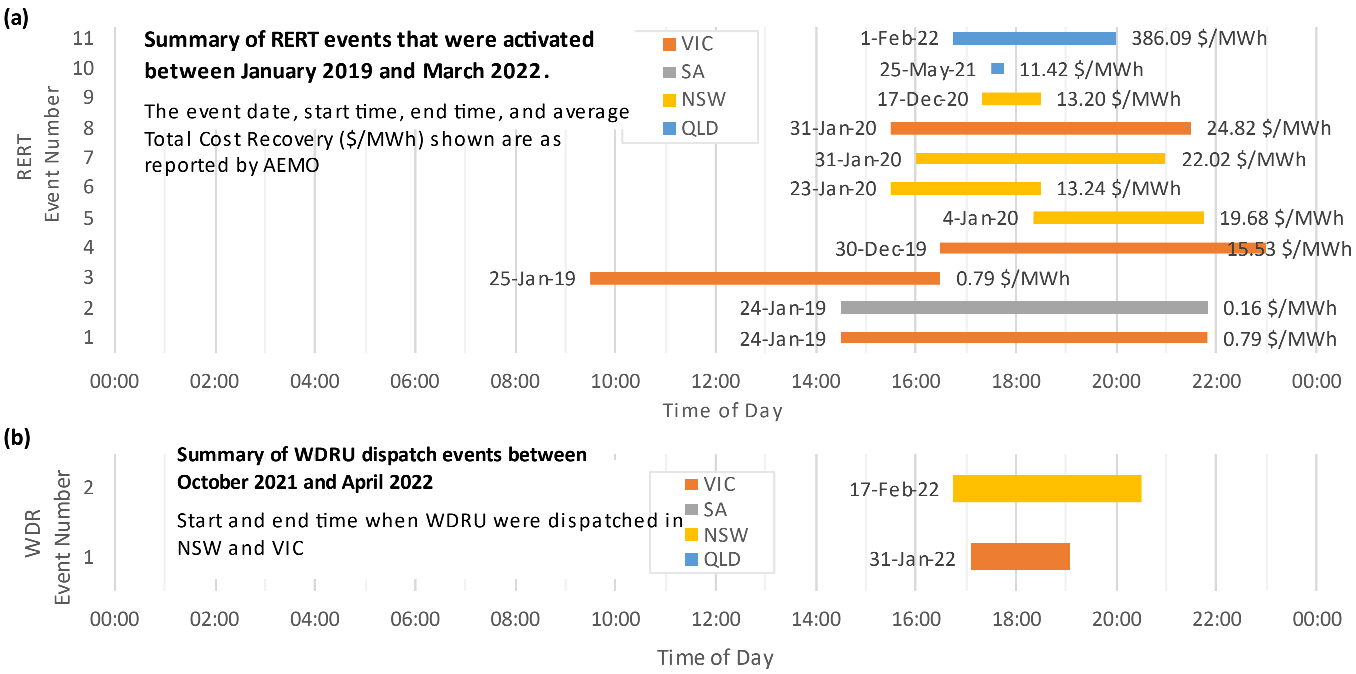


Figure 4: Summary of time and duration of (a) RERT and (b) WDR events. (Data Source: AEMO (18)).

For grid events, the demand response is a reduction in the demand that occurs at the connection point to the electricity grid (at the NMI). As the magnitude of demand response cannot be measured directly, it is estimated by comparing the actual load profile with a prediction of what would have occurred if the site did not respond. This predicted load profile, referred to as the baseline, is estimated using the site's historical consumption. For RERT and WDR events, it is based on the consumption from the 10 or 4 most recent qualifying days, depending on the methodology (19,20)[9].

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[8] This excludes dispatches where the units were being tested as part of the commissioning process.

[9] The exact number of days depends on the methodology used, which is one of AEMO's approved baseline methodologies.

2.4 Method of Participating in Grid Events

When considering using gas-fired generation to respond to grid-level events, building owners can participate through a third-party service provider that acts as an aggregator to consolidate the response across multiple sites. For sites with a cumulative generator capacity exceeding 1 MW, direct market participation is possible, albeit probably unattractive. Table 3 summarises the differences between direct participation in the market and participation through an aggregator.

Table 3: End-users participation in demand response - directly or through an aggregator.

End-User - Direct market participation	Aggregator – Market participation (with many end-users)
End-users will need in-house electricity market and engineering expertise	End-users will not need in-house electricity market and engineering expertise is provided by Aggregator
Require minimum 1 MW of dispatchable load (for the wholesale demand response mechanism)	Lower minimum requirement for dispatchable load. The requirement varies depending on the Aggregator.
Close control over pricing returns from event	End-users receive financial returns from the Aggregator. Aggregators may offer a variety of revenue models, some solely based on share pricing returns from the event, and others based on a combination of a fixed annual return based on a commitment to participate in a period, with additional returns if an event occurs.
Requires full administration and compliance time/effort	End-users require limited administration and compliance time/effort
Requires registration as a market participant, engagement with industry, and ongoing assessment of the schemes	Aggregator manages the engagement with industry and ongoing assessment of the schemes
Requires the installation of compliant equipment such as metering and telemetry (end-user provided)	Requires the installation of compliant equipment such as metering and telemetry (generally, the Aggregator will provide)
Participation in multiple different types of market events/ mechanisms may require separate market registration and different metering and telemetry requirements.	End-user can participate in different market events/mechanisms through the aggregator

Providing demand response may be difficult for customers to participate in without representation and expertise. In the example of the WDRM, customers need to be able to provide a minimum of 1 MW of dispatchable load, manage the administration (and compliance) requirements as well as have the necessary infrastructure to enact the process to respond to demand response signals. The specialist requirements are likely to be outside an average consumer's core business and present a significant barrier to entry for individual property owners.

Consumers interested in participating can engage with an Aggregator, who manages the process on their behalf. Aggregators, or Demand Response Service Providers (DRSP), play a leading role in the WDRM. Acting on behalf of multiple end customers, the registered participant takes ownership of the administration and compliance requirements, as well as providing some of the telemetry and technical equipment to allow the end customer to participate in such schemes.

With the WDRM, the DRSPs manage the aggregation of demand-responsive, controllable load across multiple end-customers and manage the scheme registration and activities, including:

- **Registration** –DRSP registration and wholesale demand response unit (WDRU) classification, demand response capacity, and eligibility status.
- **Settlements** – calculations and financial flows at the single WDRU
- **Baselining** – eligibility criteria and baseline methodology to allow establishment of the counterfactual against which demand response settlement can occur for both the DRSP and the Financially Responsible Market Participant (FRMP).
- **Prudential** – management of DRSP prudential risk through the standard collateral requirements setting and prudential processes.
- **Dispatch and forecasting** – dispatching, pre-dispatch, and short-term forecasting of WDRU energy to occur primarily through a new type of scheduled load (WDR) which is issued load reduction dispatch targets.
- **Demand side participation** – DRSP data requirements in the medium-term forecasting timeframes to be delivered through the demand side participation information portal.

Aggregators or DRSPs can be either retailers or specific third parties who provide services to enable customers to participate on the demand markets. In some cases, energy retailers may offer services to non-retail customers.

3 Methods

3.1 Methodology Overview

The primary objectives for this project are to develop a strategy for operating existing under-utilised cogeneration/trigeneration gas engines as demand response units, analyse the business case for such operations, and develop guidelines to assist sites to achieve positive outcomes.

To achieve these objectives, the following methodology was used:

1. Identification of data required for this research project. The types of data required to meet the project objective were identified. This included identifying the specific building data and electricity market data required in the analysis.
2. Onboarding of the pilot study site onto the Data Clearing House (DCH). The building data from the pilot study site, that has both trigeneration and PV generation capabilities, was onboarded onto the DCH. This involved identifying the source of the required building data and current flow of data through the building's systems. Next, the streams of data between CopperTree Analytic's Kaizen Platform[10] and the DCH were established. The data was linked to building models created on DCH for the pilot study site. The models also included details of the trigeneration system.
3. Analysing the data. The building data from the pilot study site was analysed in conjunction with data from the National Electricity Market and the information obtained from energy retailers and demand response service providers. Where required, data from other sites were used to supplement the pilot study data.
4. Investigation of how building owners can participate in wholesale demand response mechanism. This encompassed consultation with demand response service providers and electricity market participants.
5. Development of a Building Owners' Guide to help building owners determine if the use of gas-fired generation should be further considered in their case. The guide includes strategies to estimate the financial

[10] CopperTree Analytic's Kaizen Platform is an analytics platform/tool that works in conjunction with the building management systems.

and environmental impact of using gas-fired generators to respond to demand at a site level and to events in the grid.

3.2 Scenarios Considered:

The following two scenarios were considered:

- Using co/trigen units to respond to a site demand event (Section 4). The event considered in this analysis is a sudden decrease in on-site PV generation.
- Using co/trigen units to respond to grid demand events (Section 5).

Parameters used in the analysis were derived from live building data. To test the sensitivity, and to help make the results applicable to other sites with co/trigen systems, additional values for the parameters were used. These values were determined based on the range of values mentioned in the literature.

3.3 Data Sources

The analysis and models developed for the various scenarios were based on information from multiple sources, including:

- Direct engagement with market participants who offer demand response as a service
- Literature review data on co/trigeneration systems
- Publicly available data from AEMO and the AER[11] to determine the characteristics of market events
- Building data from a project partner. The building data used was onboarded onto the Data Clearing House.

3.4 Financial Impact

The following costs were determined and included in the financial impact study:

- Cost of operating and maintaining the co/trigen system (excluding fuel costs)
- Cost of co/trigen fuel
- Avoided grid electricity consumption cost
- Avoided peak demand cost

Where participation in the electricity market was considered (see Section 5), the following revenue items were included:

- Revenue for agreeing to participate in possible future events
- Revenue from participating in the event
- Avoided costs associated with reduced demand during RERT events

Revenue models for participating in the grid events were identified in consultation with third parties who provided demand response programs. Further details and values used for costs are provided in Appendix A.1.

[11] Further details provided in Appendix A and Appendix B.

3.5 Environmental Impact

The environmental impact was assessed by comparing the emissions generated when operating the co/trigen systems, with the emissions from grid electricity consumption.

Key inputs into determining the environmental impact are:

- the amount of gas consumed,
- the avoided volume of grid electricity consumption,
- the emissions factors for the gas consumption, and
- grid emission factor

Two sources were used for the emissions factors:

- the National Greenhouse Accounts (NGA) Factors published by DISER in 2021 (11), and
- publicly available AEMO data (see Appendix A.2 and Appendix B for further details).

The NGA Factors were also used to assess the impact on NABERS ratings[12]. Meanwhile, AEMO data was used to estimate the grid emissions intensity for each region in the NEM was estimated[13], for each 5 min interval period, enabling the true impact of replacing grid electricity consumption with gas-generated electricity to be assessed. Scopes 1,2 and 3 emissions factors were considered, where possible.

4 Responding to Short-Term Changes in On-Site Renewable Generation Output

4.1 Overview and Operating Strategy

The operation of a gas-fired generator to minimise peak demand impacts of short-term changes in on-site renewable generation is predicated financially on the reduction of peak demand charges. However, if this is to be a successful strategy, the generator has to be used to manage *all* potential peak demand events rather than just those initiated by the on-site renewable generation[14]. The demand management strategy for this would work as follows:

1. A peak demand target is set at the beginning of each new demand charging period.
2. Whenever the monitoring indicates that the target peak demand is at risk, the generator is operated to attempt to maintain the demand just below the target.
3. As the threat of a new peak demand event decreases, the generator output is throttled back to the minimum.
4. After the generator minimum run time has been reached and the threat of a new peak event has passed, the generator can be turned off.
5. If the demand target is breached, the resultant peak becomes the new demand target for the balance of the demand charging period.

[12] NGA Factors are used in NABERS ratings (23)

[13] The emissions calculated using AEMO data are estimates as the method uses the fuel mix of power generation within each state and does not account for interstate transmission (i.e. where electricity generated is consumed in a different states).

[14] As otherwise, the peak demand could be set by factors other than the on-site generation, thereby rendering any attempt to moderate impacts arising from the on-site renewable generator void.

In this project, only the potential interactions between short-term drops in on-site renewable generation and gas generator operation were assessed. The ability of gas-fired generators to meet the short-term decrease in renewable energy generation varies depending on multiple factors:

- The generator's capacity relative to the PV array size (which influences the magnitude of the decrease in renewable generation)
- The time taken for the generator to respond: This is the combined time of detecting the change in renewable energy generation, the time taken for the gas generator to start up and ramp up to the targeted power output. It will therefore depend on the electrical submeter interval timing and response time of the gas generator and associated controls.
- Presence and scale of batteries available to manage the delay in generator output response to a demand event.

An illustration of the operating strategy is provided in Figure 5. The operating strategy takes into consideration on-site renewable generation, operation of the gas-fired generator, and charging of a battery during the initial stages of the event. Further details are provided in Section 4.2.

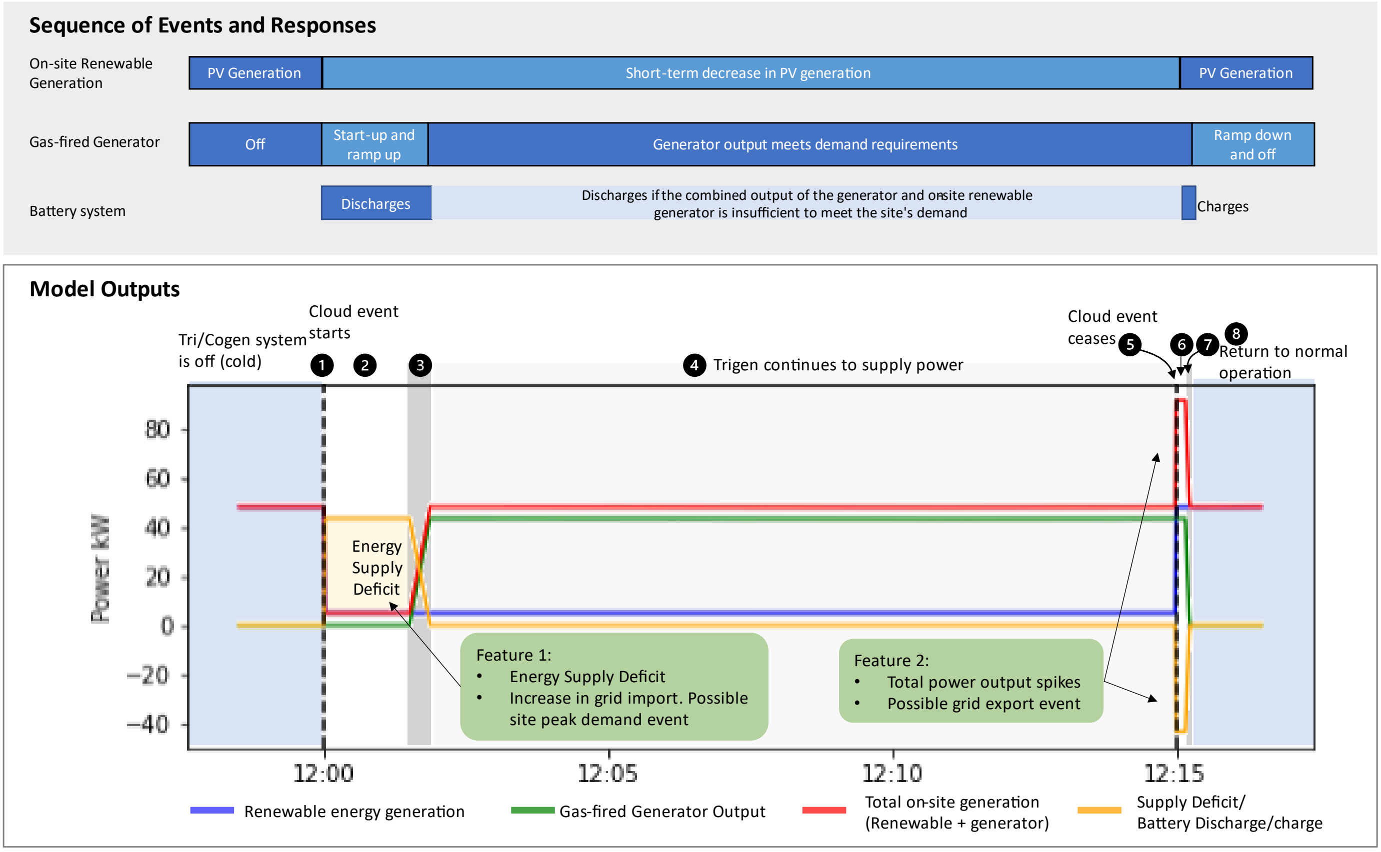

Figure 5: The sequence of events/operation mode of a gas-fired generator in response to a short-term decrease in on-site renewable generation output. The resulting model outputs is shown (below).

4.2 Energy Perspective - Meeting the local demand

4.2.1 Event and Responses Modelled

The ability for co/trigen units to meet short-term decreases in on-site renewable generation was investigated using the following three steps:

Step 1: Trigger - The triggering event
Step 2: Response Action - The co/trigen generator response
Step 3: Outcome – The impact of the response

These three steps are further described in this section (section 4.2.1). Integration of battery storage is discussed in section 4.2.2, and the impacts of modifying the co/trigen response are discussed in section 4.2.2.

Step 1: Trigger Event (Figure 6a)

The scenario where on-site PV generation decreases for 15 mins during the middle of the day was considered. Since such a decrease can be experienced when cloud cover casts a shadow over solar panels, this event is referred to as a 'cloud event'. The PV generation profile used is shown in Figure 6. It was based on the median solar generation from a 100 kW PV array on sunny days in December, with a 90% decrease in generation at 12 pm for 15 minutes superimposed.[15] Subsequent analysis focused on the demand response between 11.45 am – 12.25 pm.

Step2: Co/trigen response (Figure 6b)

The co/trigen system's response to the short-term decrease in renewable generation was modelled as the following sequence of events:

1. The cloud event starts at 12:00 noon, and this is accompanied by a decrease in PV power.
2. The monitoring system detects the drop in output and sends an enable signal to the tri/cogen units.
3. There is a lag time between the start of the event and when the co/trigen system's power output starts increasing, similar to a hysteresis loop. Lag times investigated were at intervals of 5 sec, 90 sec, and 500 sec.
4. The co/trigen system power output ramps up to meet demand. Ramp rates of 20%, 40% and 60% of the system capacity were used. The demand/targeted power output was specified to be 100%, 120%, 150%, and 170% of the decrease in PV power generation.
5. The co/trigen continues to generate until the cloud event ceases.
6. It is assumed that 10 sec is required to register the end of the cloud event, after which the co/trigen is ramped down at a rate of 10 kW/sec.
7. The system returns to normal operation

Figure 6b shows the response of a co/trigen configured to meet 100% of the power reduction in PV generation.

Step 3: Impact of the response (Figure 6c)

[15] PV generation profile based off statistical analysis of actual PV generation from the pilot site. The 90% decrease modelled is an extreme case, as this is larger than the 90th percentile PV fluctuation magnitude observed for sunny December days at the same site. Refer to Appendix A.2 for further details.

The overall on-site energy generation during the cloud event is shown in Figure 6c. The results shown are based on a co/trigen system configured to meet 100% of the power reduction in PV generation. Two key features are:

1. Missing energy supply from the PV and co/trigen systems, at the beginning of the event. This is due to the response time of the system.
2. A spike in the total on-site generation when the cloud event ceases. This is associated with the system's response time to turning off/ ramping down. During this period of time, the PV generation returns/ increases, and the co/trigen system is still producing power.

In the absence of other on-site electricity generation capabilities or battery storage, features 1 and 2 are expected to result in a sudden increase and decrease grid import for the site, respectively. While the former may result in a peak demand for the site, the latter feature may lead to unexpected grid export as the co/trigen is still generating.

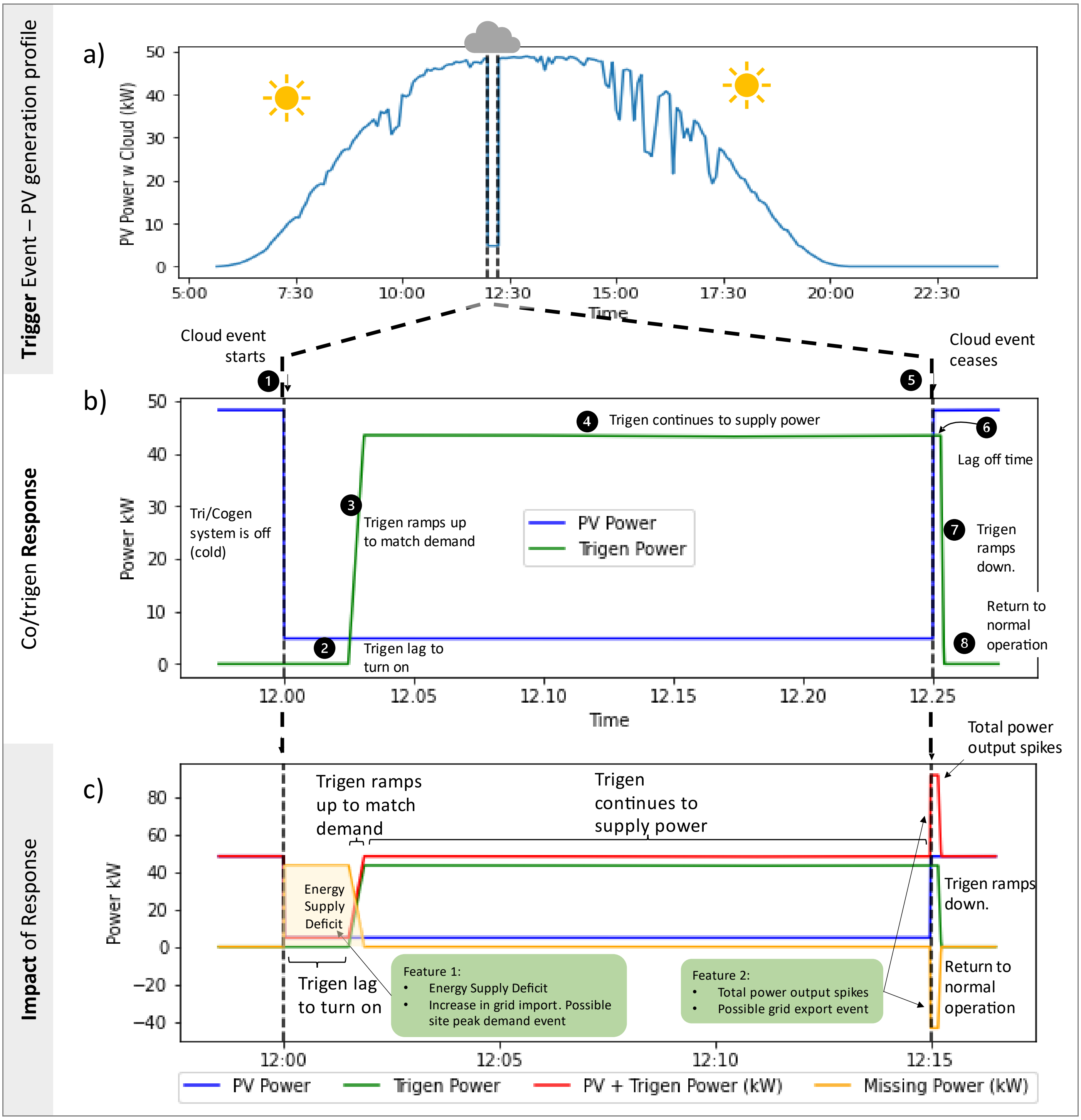

Figure 6: Trigger, response and impact for using co/trigen generators to respond to short-term changes in on-site renewable generation.

Figure 6 Additional Description: a) Trigger – a decrease in PV generation at 12:00, for a 15 min duration. This has been superimposed over a PV generation profile, for a 100 kW solar array, with a 15min cloud event super imposed. B) The co/trigen response – scenario defining a site electricity demand event – Sequence of events and generator response to meet local demand during a cloud event, for cases where the targeted power equals the decrease in PV generation. c) Overview of the modelling results showing the features of a generator responding to a local demand triggered by a cloud event. Response when the generator power output matches the drop in PV generation.

4.2.2 Co/Trigen as Demand Response without On-site Battery Storage

Strategy/ Method

For sites without on-site battery storage and where the co/trigen generators have sufficient capacity, it is possible to configure the generator's response to minimise/avoid grid peak demand. The impact of increasing the co/trigen's target power output to a value higher than the decrease in PV generation is reported in this section. For example, if the PV generation reduced by 50 kW, the co/trigen is configured to ramp up to 60 kW (referred to as +20%, or 120%) instead of 50 kW. This extra energy helps to counter the 'missing' energy, when 5 minute average power readings are considered (since the metering time intervals are typically at least 5 minutes).

Figure 7a shows the features of the co/trigen response to a cloud event under this model of co/trigen response. The key difference between this response, with that of the previous response model considered (in section 4.2.2), is the 'excess' power generated by the trigen. Assuming that the site has no additional energy sources, then the missing energy shown in Figure 7a is accounted for as additional electricity imported from the grid.

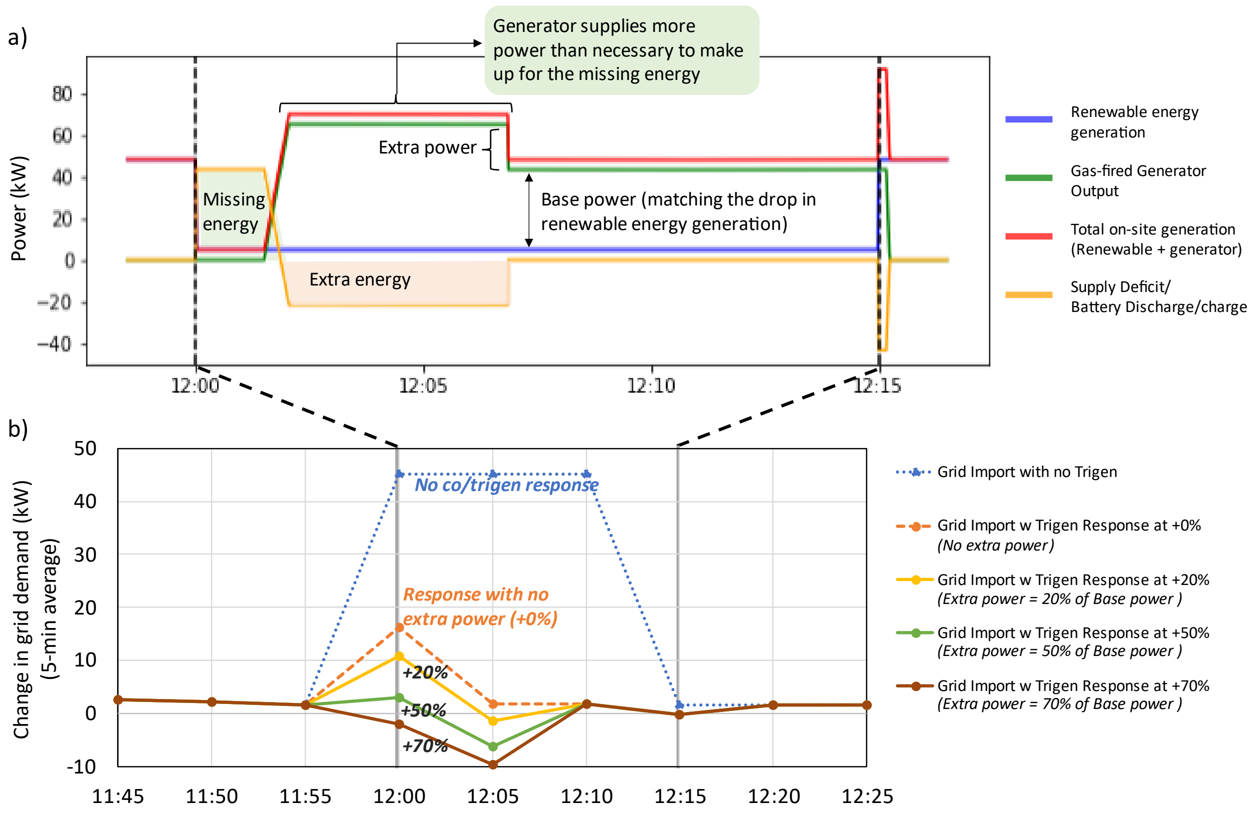

Figure 7: Effects of varying the co/trigen power output when responding to a local demand triggered by a cloud event.

Figure 7 Additional Description: a) Features of a co/trigen response when the co/trigen power output exceeds the drop in PV generation. b) Changes in grid import during a 15min PV generation reduction event under different co/trigen response scenarios. (Results for the analysis using the parameters: 100 kW solar array, a 600kW generator with 90s lag-on time and 60% max capacity/min ramp rate)

Figure 7b shows the change in average grid electricity demand (at 5-minute intervals) relative to when a cloud event does not occur. Different co/trigen power output scenarios were considered; these were:

1) When there is no co/trigen response
2) When the co/trigens system's power output matches the PV generation deficit
3) When the co/trigen is configured to generate 20%, 50% and 70% more power than the PV generation deficit in the first 5 minutes.

The results indicate that altering the magnitude of the co/trigen's target power output influences the site's grid electricity demand. Specifically:

- Grid demand decreases as the co/trigen power output is increased, and
- Grid peak demand is avoided when the co/trigen power output is more than 1.5 times the decrease in PV generation.

This analysis indicates that the co/trigen system can help to either minimise the peak demand event or eliminate it entirely. This, in turn, may lead to a site incurring additional costs in the form of peak demand charges. It should be noted that the operation of the generators at such events do not always results in avoided peak demand charges as peak demand charges are determined based on peak events across 1 – 12 months, depending on the electricity tariff a site is on.

4.2.3 Co/Trigen as Demand Response with On-site Battery Storage

Strategy/ Method

On-site batteries can be integrated into the site's operation via the following modes:

1. Battery discharges during the initial stages of the event, when the gas-fired generators are starting up and ramping up
2. Battery discharges during the middle of the event if the combined output of the generator and on-site renewable generator is insufficient to meet the site's demand.
3. Battery charges when the event ends (i.e. on-site renewable energy generation increases), and the gas-fired generator is either awaiting the shut-down signal or ramping down.

In this section, only the first mode is considered (i.e. managing the deficit in energy supply – feature 1 in Figure 6c). It is possible that in the absence of strategies to manage the deficit in energy supply, a peak demand even could be created, leading to higher peak demand charges. The battery size required to minimise the chances that this event results in a grid peak demand event for the site was analysed.

In the analysis, the size of battery required was equated to the magnitude of the energy supply deficit calculated. This approach is idealised but reported as a starting point for future improvements. The method used uses the following assumptions:

- The battery is fully charged at the start of the event,
- The battery is capable of operating up to 100% depth-of-discharge.
- The battery has a response time of that is sufficiently quick
- The battery has a discharge rate (power) that matches the decrease in PV generation.

The following were not considered in this analysis, but must be in future studies:

- Long-term impact of the battery life
- Optimal battery size to enhance the battery life, whilst permitting the site to respond to the event defined.

Results and Discussion

Figure 8 summarises the size of battery (kWh) required per kW of the solar array capacity, as a function of the ratio of PV array to co/trigen capacity increases. Results suggest that the size of battery required depends on multiple variables including the size of the PV array relative to the co/trigen capacity, and co/trigen lag on times. Larger batteries are required for sites where:

- The PV array size is larger, or if the magnitude of on-site renewable energy generation fluctuations is larger
- Co/trigen systems have longer response times (referred to as lag-on times)[16]
- The generators in the co/trigen systems have slower ramp rates

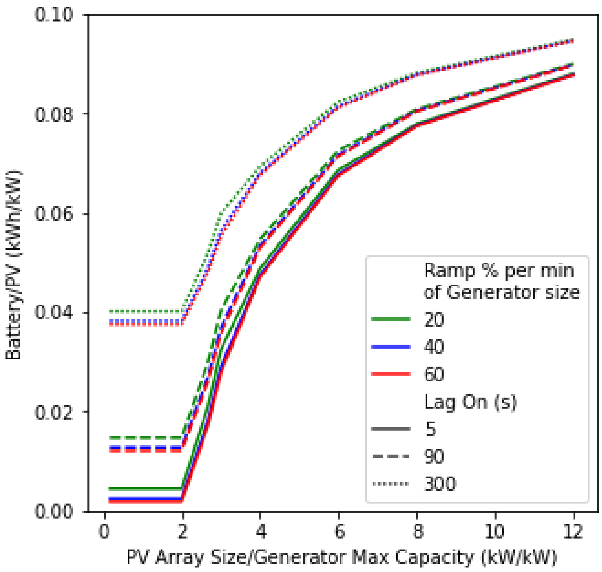

Figure 8: Size of battery required to meet the gap in demand at the start of a cloud event.

Results indicate that there is a threshold based on the ratio of PV array size to co/trigen capacity, beyond which the size of battery required increases drastically. Under the parameters used in this analysis, the size of battery required to avoid an increase in grid consumption increases where the PV array size is more than twice the co/trigen capacity, as shown in Figure 8. This PV array size/generator capacity threshold is expected to vary depending on the location of the building and the typical magnitude of fluctuation in PV generation. The threshold is expected to be lower for sites that experiences larger fluctuations in PV generation (relative to their PV array size). Batteries are likely not required for sites where the PV array size is smaller than twice the co/trigen capacity, and the co/trigen system has a quick response time.

Note that this battery size threshold was based on an assessment that only considered the battery discharging in the initial stages of the event. It assumes that the duration between events is sufficient for the battery to be recharged and that charging will not create a peak demand event. The cost-effectiveness of battery installation was not assessed.

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[16] This is a direct consequence of compensating for a supply deficit over a longer duration. Hence, a faster responding system would be most favourable to minimise the battery storage requirements and/or changes of raising a peak grid demand event for the site.

4.3 Financial Impact

The financial impact of using the co/trigen system to respond to short-term changes in on-site renewable generation output in the absence of on-site battery storage was assessed using two model equations:

1. Monthly Cost (Equation 1) – this is the total monthly cost of operating the gas generators in response to the changes in on-site renewable energy generation and then
2. Net financial Impact (Equation 2) – based on the comparison of the monthly cost for cases where the generators are operated against the case where generators are not used to respond to the event. A positive value indicates that there is a net financial benefit.

4.3.1 Model Equations

$$\boldsymbol{Monthly\ Cost} = Electricity\ Volume\ Charge + Monthly\ Peak\ Demand\ Charge + Gas\ Consumption\ Charge + Annual\ co/trigen\ \ O\&M \times \left(\frac{1}{12}\right) \quad \text{Equation 1}$$

Where:

- *Electricity Volume Charge* is the cost of grid electricity consumed. In the analysis, this is calculated as the energy supply deficit (an output of the model, shown as Feature 1 in Figure 5) multiplied by the electricity consumption charge rate ($/kWh)

- *Monthly Peak Demand Charge* is used to estimate the peak demand charge that an end user may incur, assuming that the event being considered is a peak demand event. In this analysis, the charge is determined by multiplying the magnitude of the energy supply deficit feature (in kW) with the peak demand charge rate ($/kVA), assuming a power factor of 0.9.

- *Gas Consumption Charge* is the cost of gas consumed by the generator. It is estimated using the following expression, which accounts for the amount of electricity that is produced by the generator, the generator's energy conversion efficiency (η_{el}), and price of gas.

$$Gas\ Consumption\ Charge = \frac{co/trigen\ \ Generation\ (kWh)}{Generator\ efficiency\ (\eta_{el})} \times Gas\ Consumption\ Unit\ Price \times 0.0036$$

- $Annual\ co/trigen\ \ O\&M$ – this is the annual cost of operating and maintaining the co/trigen system. The division by 12 yields the monthly cost incurred by the end-users. This cost excludes the generator fuel cost.

- The *Gas Consumption Unit Price ($/GJ), Electricity Consumption Charge rate ($/kWh)*, and peak demand charge rate ($/KVA/month) can be determined from the utility bills.

$$\boldsymbol{Net\ Financial\ Impact} = Avoided\ Energy\ Volume\ Charge + Avoided\ Monthly\ Peak\ Demand\ Charge - Gas\ Consumption\ Charge - \left(Annual\ \ co/trigen\ \ O\&M \times \left(\frac{1}{12}\right)\right) \quad \text{Equation 2}$$

Where:

- *Avoided Energy Volume Charge* reflects financial savings associated with consuming less electricity from the grid. It is the difference in energy consumption charge between the case when there is no response from the generator and when the generator is used to respond to the event. It can also be determined using the following expression:

$$\begin{aligned}&Avoided\ Energy\ Volume\ Charge\\&= co/trigen\ Generation\ (kWh)\ \times Electricity\ Consumption\ Charge\end{aligned}$$

- *Avoided Monthly peak demand charge* is a term used to represent the potential savings from a reduction in peak demand charge directly associated with reducing the site's peak grid demand. The following expression is used to quantify the savings:

$$\begin{aligned}&Avoided\ Monthly\ Peak\ Demand\ Charge\\&= (Max\ demand\ without\ co/trigen\ participation\\&\qquad - Max\ demand\ with\ co/trigen\ participation)\\&\qquad \times Monthly\ Demand\ Charge\end{aligned}$$

4.3.2 Results

Figure 9 and Figure 10 show the monthly cost incurred when a gas generator is operated under different scenarios. The scenarios considered were:

- When the annual cost of operating and maintaining (O&M) the co/trigen system is \$100/kWe (Figure 9) and \$50/kWe (Figure 10).
- Where the generator capacity is fixed at 75 kWe (subplots a and b), or where the site's co/trigen capacity is within 5 kWe of the required power output (subplots c and d – capacity). The capacities of the co/trigen systems are labelled in Figure 9 and Figure 10.
- The situation where in the absence of the co/trigen responding, a peak demand event would have occurred (subplots a and c – savings from avoiding a peak demand event is realised) and the situation where the event would not have resulted in a peak demand event (subplots b and d – no avoided peak demand savings).
- The co/trigen system's power output is configured to either match or exceeds the decrease in PV generation (by 20%, 50%, and 70%) (categories on the vertical axis of each subplot)

The following were kept constant across the scenarios:

- The nature of the events – It is assumed that the generators respond to five 15-min events in a month. Each event is defined as a 73 kW reduction in PV generation.
- The efficiency of the generator is 25%

Results show that charges incurred from peak demand events (or savings associated with avoiding those events) and the co/trigen O&M costs are the two most significant contributors to the monthly cost of responding to these events using the co/trigen system. It also shows that the cost savings associated with averting a peak demand event need to be realised for a net financial benefit.

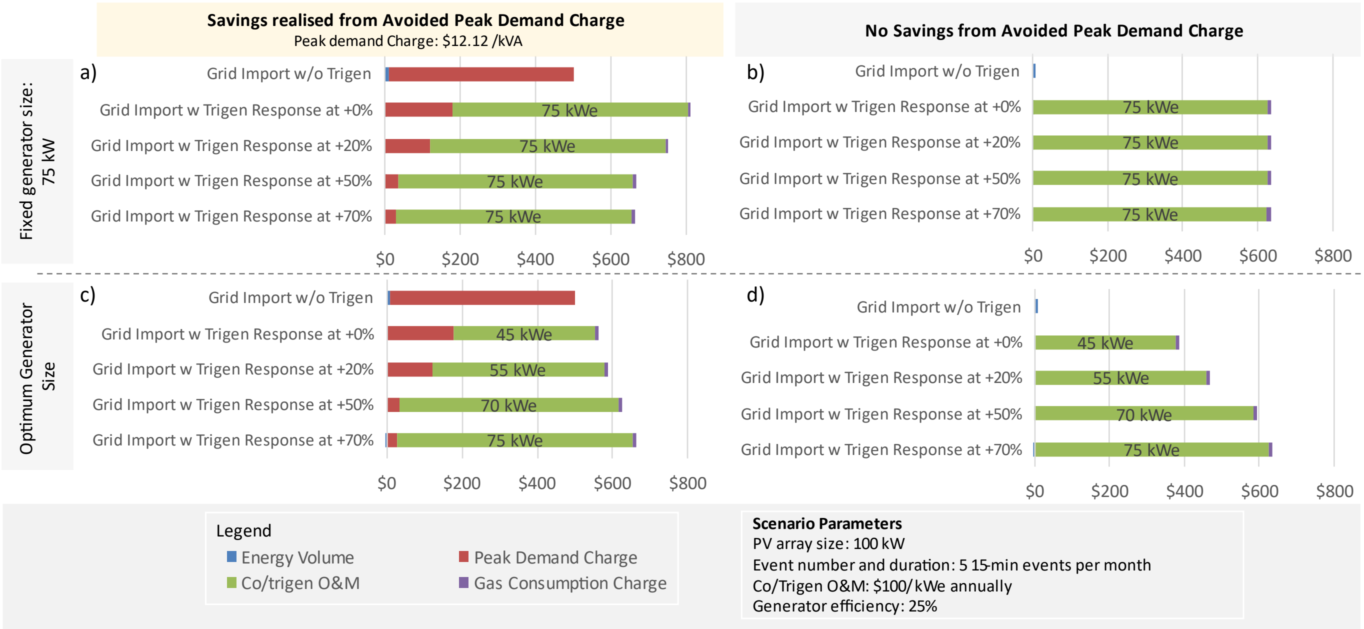


Figure 9: Break down of the monthly cost of operating a co/trigen system with an annual O&M cost of $100 per kWe, in response to five 15-minute 43 kW events in a month.

Figure 9 Additional Description: Costings provided for the case where there's no demand management, and where the gas generator power output is equal to or larger than the event magnitude (output of 43, 52, 65 and 74kW, shown as +0%, +20%, +50%, +70% in the figure, respective). Where (a, b) the generator's size is fixed at 75kWe, or (c,d) the generators responding are sized appropriately for the response, and when (a, c) the avoided peak demand charge is realised, and (b,d) no avoided peak demand charge is realised.

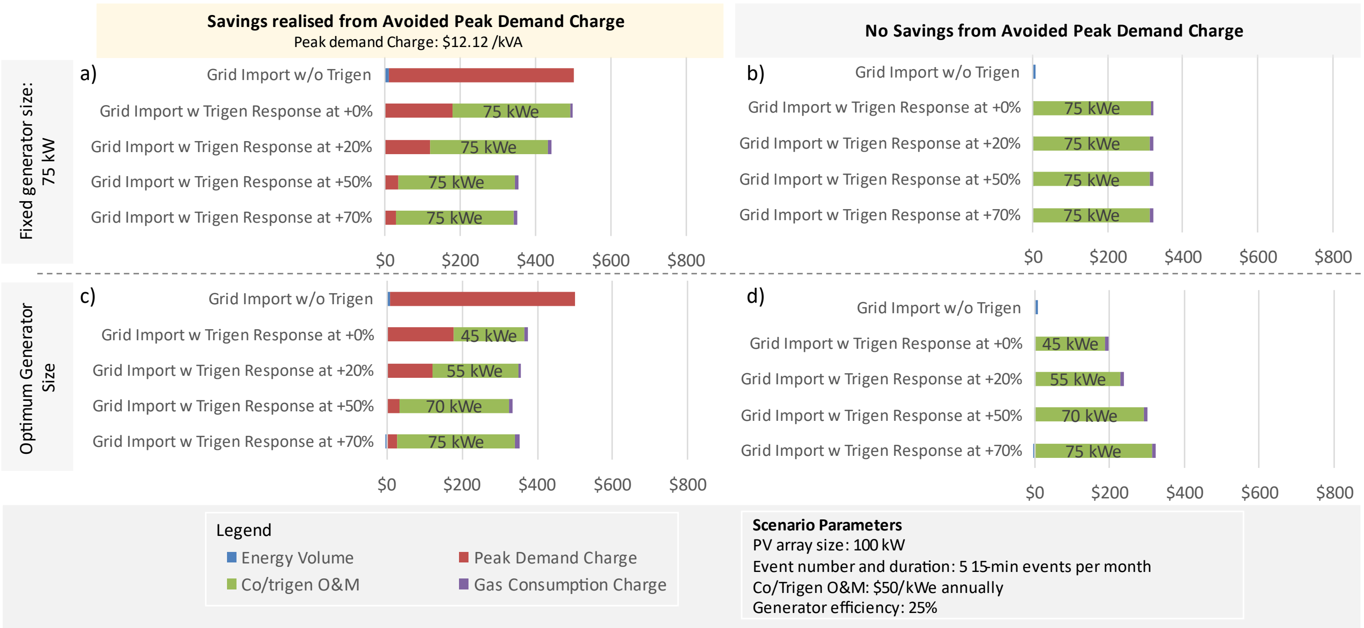


Figure 10: Break down of the monthly cost of operating a co/trigen system with an annual O&M cost of $50 per kWe, in response to five 15-minute 43 kW events in a month.

Figure 10 Additional Description: Costings provided for the case where there's no demand management, and where the gas generator power output is equal to or larger than the event magnitude (output of 43, 52, 65 and 74kW, shown as +0%, +20%, +50%, +70% in the figure, respective). Where (a, b) the generator's size is fixed at 75kWe, or (c,d) the generators responding are sized appropriately for the response, and when (a, c) the avoided peak demand charge is realised, and (b,d) no avoided peak demand charge is realised.

Figure 9 and Figure 10 show that the financial outcome is heavily dependent on the co/trigen maintenance costs; at \$100/kW (Figure 9), all scenarios are uneconomic (total costs greater than the cost without generator operation), while at \$50/kW (Figure 10), generator operation results in reduced overall costs as long as a peak demand reduction is achieved.

Figure 11 extends this analysis by presenting the net financial impact of operating the co/trigen system across a continuum of different O&M costs (including the scenarios presented in Figure 9 and Figure 10). Scenarios shown in Figure 11 are:

a) A site with a 75kW generator responding to a 43kW event, with the magnitude of the generator response configured to either meet or exceed[17] the decrease in PV generation (Figure 11a, this expands on the scenarios considered in Figure 9(a,b) and Figure 10(a,b)).
b) A site responding to a 43kW event, and the generator output is configured to maximise the generator capacity. Depending on the generator size, the output may either meet or exceed the decrease in PV generation (Figure 11b, this expands on the scenarios considered in Figure 9(c,d) and Figure 10(c,d)).[18]
c) Savings in peak demand charges were either realised or not realised (Figure 11a and Figure 11b). A realisation of savings reflects that, in the absence of any co/trigen response, the event is a peak demand event (Figure 11a). Savings will not be realised when the event is not a peak demand event (Figure 11b).
d) The co/trigen electricity conversion efficiency varies (15%, 25%, 35%) (Figure 11c)

The results are based on a site with a 100kW PV array and a co/trigen system with a ramp rate of 60% capacity/min. It is is assumed that the co/trigen system responds to five 15-minute cloud events in a month (PV generation reduces by 43 kW during the event). The co/trigen generator capacities are labelled in Figure 11.

[17] the co/trigen power response either matches the PV deficit (response +0%) or exceeds the PV deficit by 70% (response +70%)
[18] Note: the generator it sized based on the required response (modelled value) rounded up to the nearest 5 kW. The size is used to determine the total O&M cost.

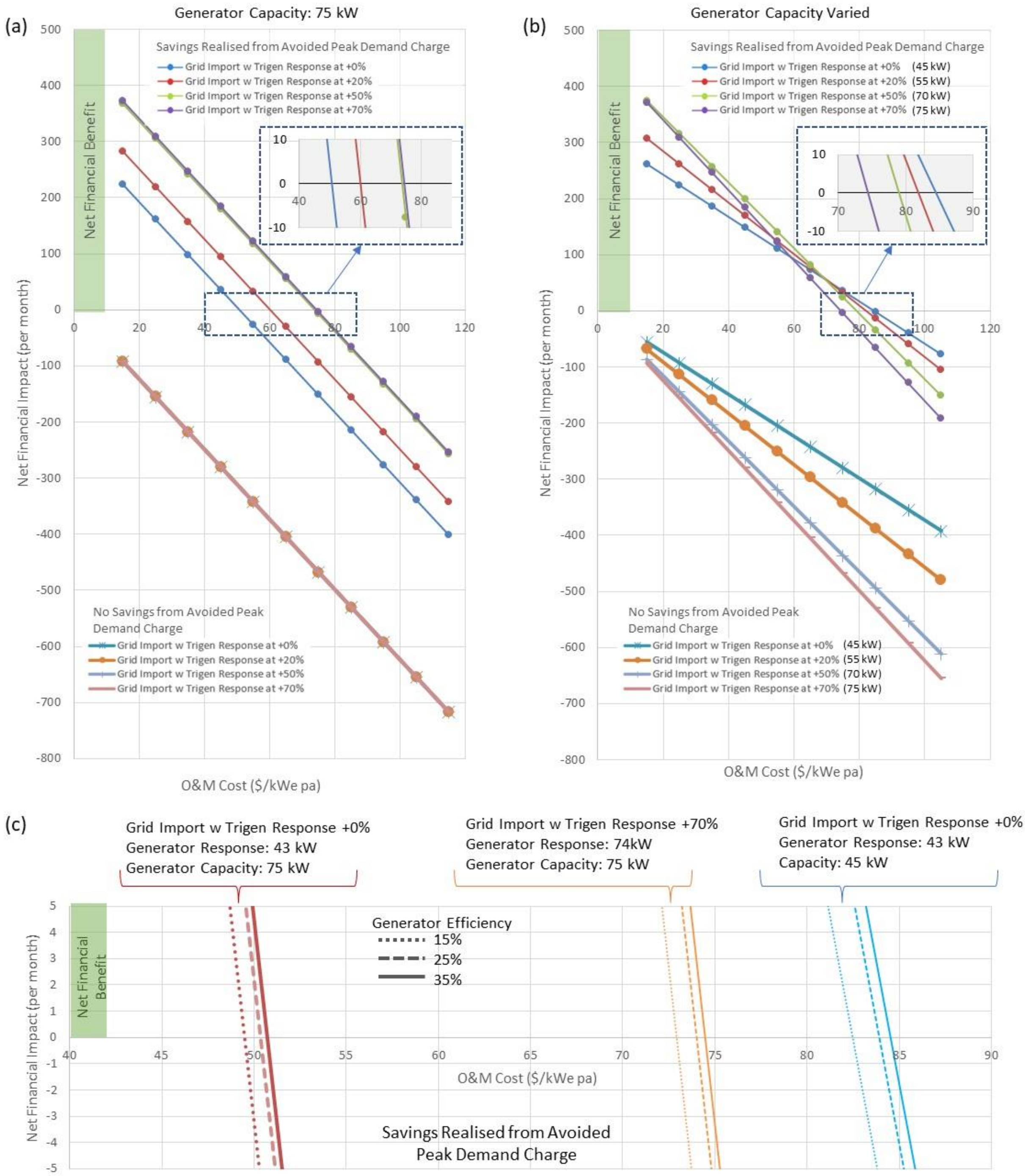


Figure 11: Net financial impact of operating a co/trigen system in response to five 15-minute 43 kW events in a month, when the generator capacity, efficiency and response are varied.

Figure 11 Additional Description: The co/trigen generator is (a) fixed at 75 kW, and (b) within 5 kW of the required output for the event. (c) Impact calculated for generators with 15%, 25% and 35% electrical conversion efficiencies.

As shown in Figure 11b, the net financial impact values calculated are consistently negative when saving from avoided peak demand charges are not realised. This observation applies to the full range of co/trigen O&M costs and co/trigen size considered. This finding suggests that if savings cannot be achieved from avoided peak demand charges, then there is no financial benefit of operating the co/trigen system to respond to site demands created by PV fluctuations.

The results also indicate that even if peak demand charges are successfully avoided, a net financial benefit only occurs when the co/trigen O&M costs are sufficiently low. The highest O&M cost for a net financial benefit (where the trend lines in Figure 11 intersect the x-axis) is typically less than $75 per kWe of co/trigen capacity. This O&M price threshold increases when the system's electrical efficiency is higher and when the percentage of co/trigen capacity used increases. The latter (co/trigen utilisation) is reflected in the higher threshold O&M cost when the targeted demand over-shoot increases. This implies that it is financially more beneficial for the co/trigen to produce a larger response if it has sufficient capacity to respond to the demand event; for example, responding at +70% instead of +0%).

Figure 12 shows the minimum peak demand charge ($/kVA) required to operate the co/trigen system, responding to on-site renewable generation fluctuations, with a financially positive outcome. For a site with a higher co/trigen O&M cost, higher minimum peak demand charge and utilisation of the generator are necessary to realise a net financial benefit (Figure 12a).

As gas prices increase, more savings from avoided peak demand charges are required for operating the generators to be financially beneficial. This can be inferred from the minimum peak demand charge increase as the gas price increases from $11.51/GJ to $46.06/GJ as shown in Figure 12b. Furthermore, participating in more demand response events is not a viable strategy to compensate for higher gas prices: As shown in Figure 12b, responding to more events when the gas prices are higher requires higher peak demand charges break even. This is due to the generator fuel cost being greater than the cost of purchasing electricity from the grid.

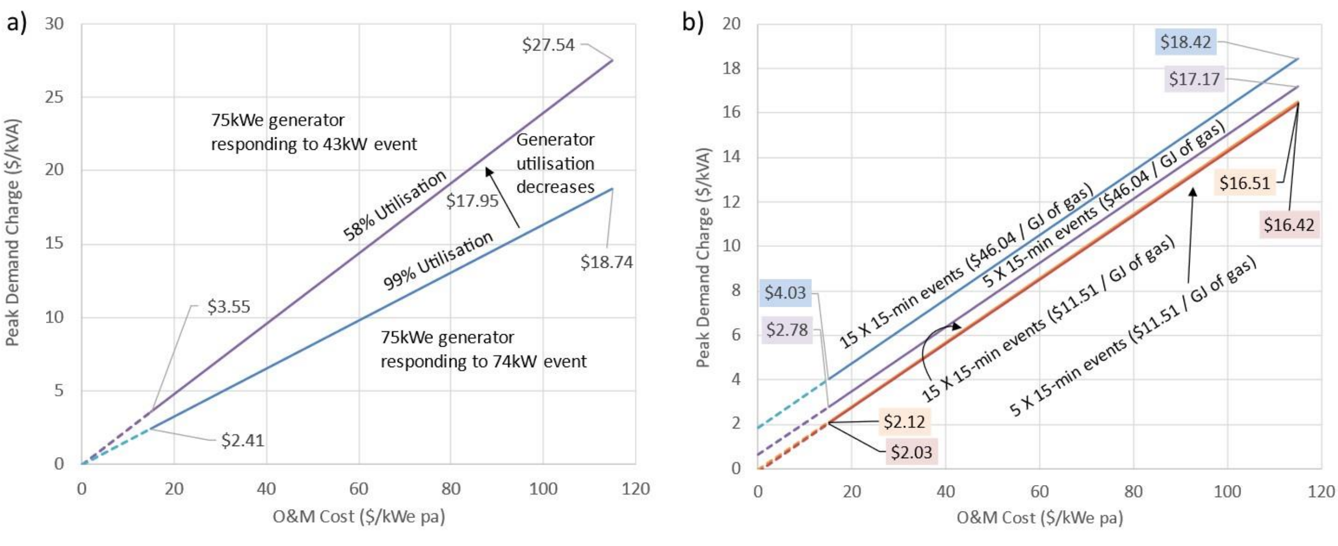


Figure 12: Minimum peak demand charge ($/kVA) required to operate the gas generators with different O&M costs ($/kWe annually) in response to on-site renewable generation fluctuations to achieve a positive financial outcome.

Figure 12 Additional Description: a) minimum peak demand charge increases when generator capacity utilised decreases; b) Minimum peak demand charge when then the number of events in a month increases from 5 to 15, and the cost of gas increase four-fold (from $11.51 to $46.04 per GJ).

4.3.1 Discussion

The financial impact of operating the gas-fired generators in response to short-term changes in on-site renewable energy can be determined by comparing the cost incurred to operate and maintain the cogeneration/trigeneration system and the cost of generator fuel with the avoided electrical peak demand charges and consumption costs.

Multiple factors that impacted the financial outcome of operating the gas-fired generators in response to short-term changes in on-site renewable energy have been identified:

- Primary factors which had the greatest impact were:
    - The operation and maintenance cost of the unit/system ($/kWe, excluding the cost of gas consumption)
    - The magnitude of the peak demand charge ($/kVA), and
    - The magnitude of the avoided peak (kVA) relative to the size of the generator
- Secondary factors included:
    - The efficiency of the generator,
    - The mode of operating the generator units (if the generator output will exceed the short-term decrease in on-site renewable energy demand),
    - Generator fuel cost
    - Frequency and duration of the events,

The overall financial benefit is expected to vary and needs to be evaluated on a site-by-site basis. This is because the magnitude of the factors listed above can vary widely for different sites and scenarios. For example:

- The cost of operating and maintaining the co/trigen system can vary widely. Values between $15 - $113 per kWe were identified (1,21)[19]. The cost of operation and maintenance could potentially be reduced to values at the lower end of this range if the maintenance of the co/trigen heat-recovery system and infrastructure can be avoided.
- Savings associated with the avoided peak demand charges heavily depend on the scale of the avoided peak demand. A greater financial benefit can be realised if the magnitude of the avoided peak demand is close to the generator capacity, which therefore maximises the generator capacity utilised. The reason is two-fold: 1) generators have higher efficiencies when operating at full load, compared to part load, and 2) the cost of operating and maintaining the co/trigen system is a fixed cost proportional to the generator size. However, the ability to maximise the generator's capacity is also dependent on the size of the on-site PV array, as well as the nature of the demand events, both of which determine the magnitude of the avoided peak if they are smaller than the generator's capacity. On this basis, is can therefore be inferred that while a reduction in peak demand can be achieved by operating the generator, the magnitude of the peak demand event and hence overall financial benefit is uncertain.
- Changes in fuel cost: the current climate in 2022 has seen a rapid increase in natural gas prices. The cost of gas consumption for building owners at present will depend on their method of purchasing gas (e.g. if it is purchased in advance, if their contracted rates are variable or fixed, and/or if their existing contract with the gas retailer is up for renewal). In this project, only variations in on-site gas consumption prices were analysed, although it is acknowledged that the cost of grid electricity also has an influence on the financial outcome.

As an example, consider a building with co/trigen system that has a 75kWe generator, with a 35% efficiency, and the co/trigen system costs $5,635 to operate and maintain annually (i.e. $75 per kWe[20]). The cost of consuming grid electricity is taken to be 14.16 cents/kWh and cost of gas is $11.51 per GJ. The event considered is 15-mins long, where the solar generation output decreased by 45kW. If the generator is operated at 74 kW, close to its capacity (i.e. at 99% utilisation/load), the avoided peak is determined to be 38 kVA. Under the assumption that there are five similar events in a month, a peak demand greater than $12 per kVA per month is required for a net-positive financial outcome to be

[19] This based off O&M costs estimated at 1.5 – 3.1% of the capex cost, and the O&M costs for the pilot study site.
[20] kWe refers to the electrical capacity (kW) of the gas-fired generators.

achieved (Figure 12a). The sensitivity of obtaining a net-positive financial benefit to the different parameters is discussed in the following points:

- **Variation 1:** A higher minimum peak demand charge will be required if the co/trigen system's O&M cost is higher. For every $1 per kWe increase in O&M cost, the minimum peak demand charge needed to balance the cost and savings increases by approximately $0.14 – 0.16 per kVA. This minimum rate of change required is lower when a larger proportion of the generator is utilised. For example, if the generator continues to respond to 74kW demand events, an increase in O&M cost by $10 per kWe (i.e. from $75 per to $85 per kWe) will require a higher peak demand charge of $12.40 per kVA per month (increase by $1.40 per kVA per month) before a financial benefit can be realised.
- **Variation 2:** If the 75 kWe generator is programmed to operate at a lower output, (say) 43 kW, in response to the same event, the generator will be operating at a load of 58%. Then the magnitude of the avoided peak demand will reduce to 26 kVA. Under the same assumption that there are five 15-min events in a month and the O&M cost is $75 per kWe, a peak demand charge greater than $18/kVA per month is required before operating the gas generator becomes financially beneficial. The minimum peak demand charge will increase by $1.60 (to $19.60) should the O&M cost increase by $10 to $85 per kWe.
- **Variation 3:** The cost of gas also affects the financial outcomes of operating the generators. A four-fold increase in gas prices from $11.51/GJ to $46.04/GJ leads results in a $0.67 per kVA per month increase in the minimum peak demand charge required for the total cost and savings to even out, regardless of the O&M cost. This sensitivity analysis assumed that the price of electricity consumption (cents/kWh) remained constant.

The analysis shows that if gas generators are operated to meet short-term changes in on-site renewable energy generation, they should be operated for general demand management, with careful selection of the events that the generator responds to. This is based on the findings that peak demand savings must be realised for a net-financial positive outcome, but the minimum peak demand charge ($/KVA) required increases with the number of events the generator responds to. The importance of selecting the 'right' events to respond to increases with the price of gas, as the minimum peak demand charge threshold increases by a larger magnitude. The financial outcome, however, is marginal and sensitive to multiple factors and hence needs to be evaluated on a site-by-site basis. This indicates that a more reliable positive financial outcome would require the capture of revenue streams available from grid demand event response, as discussed in section 5.

4.4 Environmental Impact

The environmental impact of using a gas generator to respond to short-term changes in on-site renewable generation can be assessed by comparing the emissions associated with using the generators, and the consuming electricity from the grid.

Figure 13 compares the emissions intensity of gas generators with the real-time grid emissions intensity at different times of the day for each region in the National Electricity Market (NEM). The emissions intensity of a gas generator (horizontal lines in Figure 13) varies depending on the generator's efficiency and location; the latter occurs as the emissions intensity of gas differs marginally for each state/territory (11).

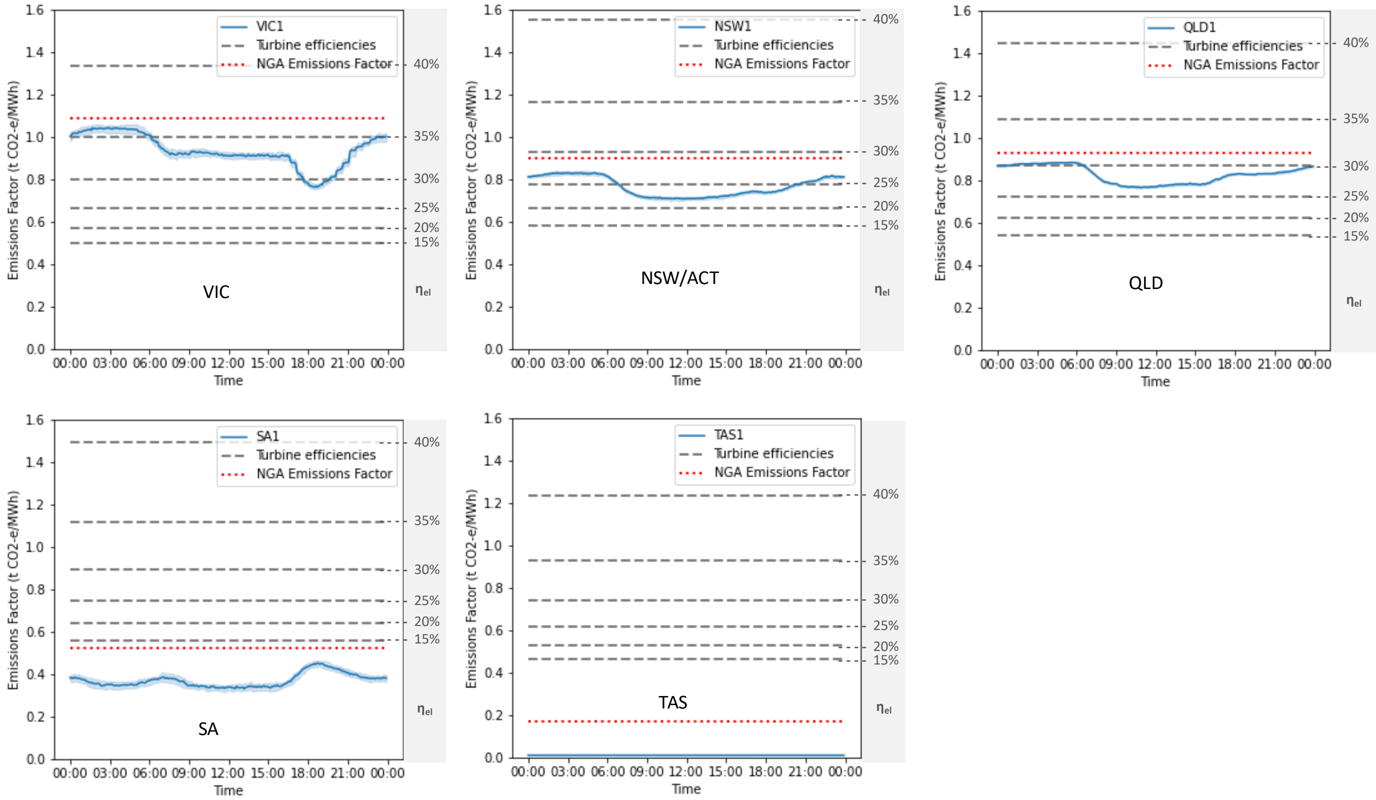


Figure 13: Average real-time grid emissions factor at different times of the day (between March 2021 – April 2022), compared with annualised grid emission (National Greenhouse Accounts Factors (11)), and the emissions intensity of gas-fired generators of varying efficiencies (15 -40%).

Figure 13 shows that the emissions associated with operating a gas-fired generator are higher than the real-time grid emissions at any time of the day, and higher than the annual grid emissions factor, in TAS and SA. However, meanwhile, operating gas-fired generators in NSW, VIC and QLD can result in a net positive environmental impact, if the generator efficiencies are high enough.

From a site perspective, the emissions intensity is judged from the perspective of average annual emissions factors which, being higher than the event-specific factors, are generally favourable for the use of the generator. This effect is amplified for NABERS ratings, which are based on lagging indicators of annual emissions intensity. At the site level, emission calculations for reporting and for NABERS ratings are based on annual average emission factors. In 2022, the current state of play is:

- VIC: Gas generator operation is likely to reduce overall site emissions
- QLD, NSW, NT, and WA: Gas generator operation may reduce emissions for generators operating at efficiencies above 23%, 26%, 27%, and 29%, respectively.
- SA and TAS: Gas generator operation will increase emissions

While the real-time emissions impact of gas generator use may be detrimental, this ignores the bigger picture question of the extent to which the availability of demand-side resources enables the market to have a higher proportion of renewable energy use. Comparing the low frequency and short duration of demand response events against the year-round emissions reduction of any incremental addition to renewable generation capacity enabled by the demand management services provided, it would seem likely that the net result is strongly in favour of the use of the generator capacity.

5 Responding to Grid Demand Events

5.1 Overview and Operating Strategy

Participation Method

For building owners looking to use their gas-fired generators to respond to grid demand events, using a third party (such as a retailer or a demand response aggregator) is strongly recommended rather than direct participation as a market-registered participant. This avoids the complexity of becoming a market-registered participant and creates new opportunities by becoming part of a portfolio of demand response. It enables demand response below 1MW to participate and provides a level of flexibility in response not necessarily available as a stand-alone participant.

Triggering Method

In general, from the perspective of the building owner, the mechanics of operating varies depending on the third party engaged and the type of demand response program. Two types of mechanisms were identified during our review process:

- Mechanism 1 – Manual triggering. The third party contacts the building owner/nominated building contact to inform them of an event. The building owner is responsible for responding to the demand by turning the gas generator on at the start of the event and off at the end of the event. This mechanism is more widely used.
- Mechanism 2 – Automatic triggering. The third party informs the building owner/nominated building contact of an event. The controller installed by the third party automatically adjusts the load/ generator to meet the demand. This mechanism is less widely used.

It should also be noted that in most cases, the third party typically has no visibility of the building's operations and plant loads or requirements. The method of triggering a response is assumed to have no influence on the net financial and environmental impact analysis for the scenarios considered as part of this study.

5.2 Energy Perspective

The magnitude (in kW) of the co/trigen demand response depends on the following:

- The size of the generator(s),
- Grid import or export restrictions that a site has - this may be imposed by the Distribution network service providers,
- Restrictions associated with the co/trigen protection system, and
- The magnitude of demand response requested by the third-party, or the magnitude of demand response that the site agrees to contractually.

These were identified from the case study site’s limitations and through engagements with third-party service providers.

In this section (Section 5), only scenarios where the co/trigen system in a building is solely operated to participate in demand response events were considered. It also assumes the following:

- The site is able to meet all contractual agreements, including the magnitude of demand response agreed upon, and no contractual penalties are incurred

- The demand response magnitude selected in the scenarios does not lead to the site violating any grid import or export limitations.

5.3 Financial Impact

The financial impact of participating in grid demand events is affected by the revenue a site receives. Revenue models for participating in the grid events were identified in consultation with third parties who provided demand response programs. As outlined in Section 2 (Background), RERT and WDRM are two types of grid demand events that can be considered. The characteristics of these events are summarised below:

RERT Events:

RERT events are enacted by AEMO when there is a shortfall in electricity demand. Notification of the possibility of these events is provided notification periods of days to hours, and the events typically last between 3 to 6 hours. Note that if no RERT events are preactivated or activated, then the building owner does not receive any revenue.

For RERT events, the revenue is dependent on:

- The number of RERT pre-activation events
- The number and duration of activated events,
- And the demand response capacity (i.e. the amount by which a site can reduce its demand during a RERT event).

During RERT events, end-users incur a market charge based on the amount of electricity consumed from the grid during the RERT event. Consequently, operating the gas generators during a RERT leads to additional savings, through a reduction in the market RERT charge, albeit of second order. The charge ($/kWh) varies depending on the event and is calculated by AEMO for each event to cover the cost of the RERT event.

WDRM Events

The wholesale demand response mechanism enables an end-user to reduce their grid demand and receive payment based on the demand reduced (relative to a baseline), and the electricity spot/market price. While, in theory, participation can occur at any time, it is expected that participation will most likely occur (or be requested by third parties) when the spot price is high. Two different revenue models were identified:

- **Contracted Capacity Agreement**: Revenue is based on a contracted capacity. The end-users receive an annual payment, regardless of the occurrence of events, based on an agreed demand response capacity. This is the magnitude of demand that the end-user agrees to reduce when called upon. The end-user will also receive an additional payment based on the number and duration of events and a fixed dispatch payment rate ($/MWh).
- **Spot Price Share:** In this form, end-users receive a portion of the market price at the time the demand response event. Revenue is only received if end-user participates in an event.

The following points on peak demand charges and peak demand management, in the context of RERT/ WDRM events should be noted:

- <u>Avoided peak demand charges were not included in the analysis.</u>
  Participating in a demand response event (RERT or WDRM) will likely lower the maximum demand for that particular day, compared to the estimated demand if the site did not respond. However, this reduction is unlikely to yield a reliable peak demand savings because there is no guarantee that a RERT of WDRM event will align with the building's monthly or annual peak.

- The impact of using gas generators as demand limiters, in the absence of on-site renewable generation capabilities, was not evaluated as part of this project; this style of operation could feasibly generate peak demand savings. However, this mode of operation could lead to a lower RERT/WDR demand baseline[21] for the site and hence reduce the amount of revenue available from these mechanisms if the gas generators were used to limit a site's peak demand on a regular basis, or on days leading up to the grid event.

5.3.1 Equations Used

The net financial impact of using co/trigen systems to participate in grid demand events can be expressed as Equation 3. It is a combination of revenue, avoided costs and costs incurred for each type of demand response event. Details of each cost and saving term in Equation 3 are expanded below and in Table 4.

$$\begin{aligned}\boldsymbol{Net\ Financial\ Impact}\\ &= Revenue\ from\ RERT\ events + Avoided\ Costs\ from\ RERT\ events\\ &+ Revenue\ from\ DR\ events + Avoided\ Costs\ from\ DR\ events\\ &- co/trigen\ O\&M\ cost\end{aligned} \qquad \text{Equation 3}$$

Where

- $\underline{Revenue\ from\ RERT\ events}$ depends on the number of events that are pre-activated, number of events activated in a year, the contracted capacity of demand reduction, and the duration of the event. The following expressing was used:

$$Revenue\ from\ RERT\ events = PreactivationPayment + Activation\ Payment$$

- $\underline{Avoided\ Costs\ from\ RERT\ events}$ is a combination of the avoided RERT Charges incurred (which is charged based on the site's energy consumption during the RERT event), and the avoided peak demand and energy consumption as a result of lower grid energy consumption. The following expressing was used:

$$\begin{aligned}&Avoided\ Costs\ from\ RERT\ events\\ &\qquad = Avoided\ RERT\ Charges + Avoided\ peak\ demand\\ &\qquad + Avoided\ energy\ consumption\end{aligned}$$

- $\underline{Revenue\ from\ DR\ events}$ depends heavily on the details of the contract between the building owner and the third party that participates in the market. Two methods of estimating the revenue were identified:

    - Option 1: Contract Capacity Agreement:
      Annual payment based on a contracted capacity with additional payments based on the number/ duration of events. In this case, the revenue is expressed as:

$$Revenue\ from\ DR\ events = Revenue\ from\ Agreed\ Capacity + Dispatch\ Revenue$$

    - Option 2: Spot Price Share:
      Payment based on the number and duration of events. The rate is a percentage of the market price. In this case, the revenue is expressed as:

$$Revenue\ from\ DR\ events = Revenue\ from\ a\ share\ of\ spot\ price$$

[21] The baseline used to quantify the demand response is calculated based on the site's consumption for the previous 10 or 4 equivalent days, depending on the methodology used.

- $\underline{Avoided\ Costs\ from\ DR\ events}$ is the summation of avoided peak demand charges and energy consumption as a result of lower grid energy consumption. The following expressing was used:

$$Avoided\ Costs\ from\ RERT\ events = Avoided\ peak\ demand + \ Avoided\ energy\ consumption$$

- $\underline{co/trigen\ O\&M\ cost}$ refers to annual cost of operating and maintaining the co/trigen systems.

Table 4: Description of terms used to determine the financial impact of participating the RERT events.

Category	Category	Equations to estimate the cost/ savings	Further notes	Savings realised/ cost incurred regardless of whether an event occurs
RERT				
Revenue	Preactivation Payment (only occurs if a RERT event is preactivated by AEMO)	$Preactivation\ Rate\ (\$/MW) \times Capacity\ (MW) \times Number\ of\ Preactivation\ events$	$Preactivation\ Rate\ (\$/MW)$ varies depending on the third party that has been engaged. An estimate of $10000 per MW of demand capacity is used in this project (22).	N
	Activation Payment	$Activation\ Rate\ (\$/MWh) \times Capacity\ (MW) \times Dispatch\ Duration (h)$	$Preactivation\ Rate\ (\$/MW)$ varies depending on the third party that has been engaged. An estimate of $9000 per MWh is used in this project (22).	N
Avoided Costs	Market charges to recover RERT costs	$RERT\ Charge\ (\$/MWh) \times Capacity\ (MW) \times Dispatch\ Duration (h)$	$RERT\ Charges\ (\$/MWh)$ vary depending on the event. It is calculated by AEMO. For this analysis, a value of $17.13 per MWh is used[22]	N
WDR				
Revenue (Option 1)	Revenue from Agreed Capacity	$Capacity\ Rate\ (\$/MW) \times Capacity\ (MW)$	The Capacity Rate varies depending on the third party that has been engaged and the location. This is a contracted rate. A value of $50,000 per MW of agreed capacity is assumed in this analysis.	Y
	Dispatch Revenue	$Dispatch\ Rate\ (\$/MW) \times Capacity\ (MW) \times Dispatch\ Duration (h)$		N
Revenue (Option 2)	Revenue from a share of spot price	$Spot\ Price\ (\$/MWh) \times Spot\ Price\ Share\ (\%) \times Capacity\ (MW) \times Dispatch\ Duration (h)$	The *Spot Price* ($/MWh) can be obtained from AEMO dispatch price data.	N

[22] This is the average value determined from RERT events that occurred between 30 Dec 2019 and May 2021. (Refer to Appendix B)

Category	Category	Equations to estimate the cost/ savings	Further notes	Savings realised/ cost incurred regardless of whether an event occurs
			$Spot\ Price\ Share$ refers to the percentage of the spot price that the customer receives. For this	
Applicable for both DR and RERT events.				
Avoided Costs	Avoided peak demand*	$((Max\ demand\ without\ co/trigen\ participation) - (Max\ demand\ with\ \frac{co}{trigen}\ participation)) \times Monthly\ Demand\ Charge$	If peak demand charges are applied based on a rolling 12-month charge, this value should be multiplied by 12	N
	Avoided grid electricity consumption	$Electricity\ Consumption\ Charge\ (\$/kWh) \times Co/trigen\ \ Generation\ (kWh) = Electricity\ Consumption\ Charge (\$/kWh) \times Capacity\ (MW) \times Dispatch\ Duration (h)$		N
Additional Cost Incurred	Gas Consumption Charge	$Gas\ Consumption\ Charge = \frac{co/trigen\ \ Generation\ (kWh)}{\eta_{el}} \times Gas\ Consumption\ Charge\ (\$/GJ) \times 0.0036$	η_{el} is the electrical efficiency of the co/trigen system $Gas\ Consumption\ Charge$ is the cost of consuming 1 kW of gas. The cost to transport the fuel, which is incurred by the participating site, should also be included here.	N
	Co/Trigen O&M	$Annual\ Operation\ and\ Maintenance\ cost\ (excluding\ gas\ consumption)$	This is a fixed value based on the installed generator capacity. Values between $15 – $115 per kW$_e$ are considered.	Y

5.3.2 Results – RERT Events

The net financial impact of participating only in RERT events calculated for several scenarios are shown in Figure 14. In these results, the revenue associated with WDRM response was taken to be 0 (zero). Each figure shows how the net financial impact varies with the cost of operating and maintaining the co/trigen. The O&M costs shown (x-axis) are based on the total cost per kW of installed generator capacity.

In general, Figure 14 shows that as the O&M cost decreases, the net financial impact of operating the generators increases. The results indicate that the O&M cost must be below a threshold value in order to operate the generators with a net-positive financial outcome.

Figure 14 shows how the net financial benefit, and the threshold O&M cost, is affected by changes to:

- **Generator Capacity and efficiency** (Figure 14a and Figure 14b)
  The size of existing gas-fired generators in commercial buildings and their electrical conversion efficiencies influences the net financial impact. In Figure 14a, three generator sizes (0.5MW, 1MW and 2MW) are considered. In Figure 14b, the differences between a 1MW generator with 15%, 25% and 35% efficiency are compared. In Figure 14a and Figure 14b, the O&M cost threshold varies between \$36 – \$37.50 across all cases, indicating that the threshold is only marginally sensitive to generator capacity and efficiency.

- **Capacity Usage** - the proportion of generator capacity utilised (Figure 14c). Depending on the individual circumstance of office buildings, it may not be possible to run the generators at full capacity during the events (as discussed in Section 5.3). The net financial impact was determined for cases where the generators operate at full load (100%) or part loads of 75%, 50% or 25%. These are referred to as “capacity usage” and are represented by separate lines in Figure 14c. Results show that both the net financial impact and the O&M cost threshold are sensitive to capacity usage.

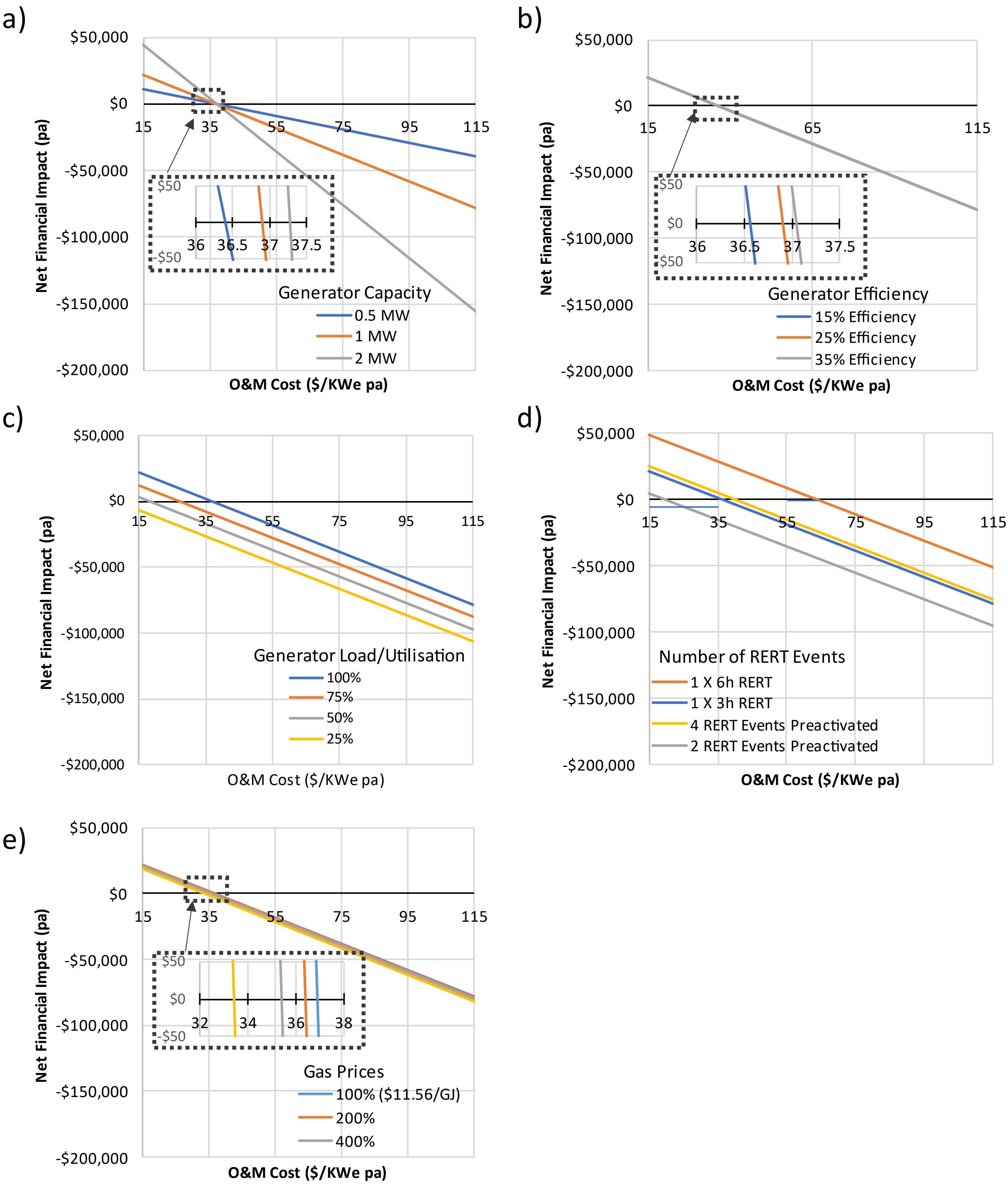
- **The number and duration of RERT events in a year** (Figure 14d)
  The net financial impact also varies with the number and duration of RERT events. This is as expected as both factors drive the revenue obtained. The following four annual scenarios were considered[23]:
  - 1 RERT event that was activated and lasted 3 h
  - 1 RERT event that was activated and lasted 6 h
  - 2 RERT events were preactivated, and no events were activated
  - 4 RERT events were preactivated, and no events were activated

  The results show that that the O&M threshold for positive net financial impact is sensitive to the number and duration of RERT events. For sites where the O&M cost is between 15 – 20 \$/KWe, the revenue from any of the RERT Event scenarios considered is sufficient. If the O&M costs ranges between 20 - 37 \$/KWe, at least four preactivated events, or one 3hour RERT event, is required. At least one 6-hour RERT event activated in a year is required for a net-positive outcome if the O&M cost is between 37 - 62 \$/KWe. For sites with an O&M costs greater than 62 \$/KWe, a positive net financial impact is unlikely to occur under any of the RERT Event scenarios considered.

- **Gas Prices** – The cost of generator fuel (Figure 14e)

[23] These scenarios were selected based on the frequency and duration of historical events. Refer to Appendix B – Electricity Market Analysis.

Figure 14 shows the results where the prices increased 2- and 4-fold from a base price of $11.51 per GJ. As expected, an increase in gas prices leads to a higher O&M threshold, and a lower financial benefit. However, the sensitivity of the O&M threshold is minor.



a)
$50,000
$0
-$50,000
-$100,000
-$150,000
-$200,000
15
35
55
75
95
115
Net Financial Impact (pa)
O&M Cost ($/KWe pa)
$50
$0
-$50
36
36.5
37
37.5
Generator Capacity
0.5 MW
1 MW
2 MW
b)
$50,000
$0
-$50,000
-$100,000
-$150,000
-$200,000
15
65
115
Net Financial Impact (pa)
O&M Cost ($/KWe pa)
$50
$0
$50
36
36.5
37
37.5
Generator Efficiency
15% Efficiency
25% Efficiency
35% Efficiency
c)
$50,000
$0
-$50,000
-$100,000
-$150,000
-$200,000
15
35
55
75
95
115
Net Financial Impact (pa)
O&M Cost ($/KWe pa)
Generator Load/Utilisation
100%
75%
50%
25%
d)
$50,000
$0
-$50,000
-$100,000
-$150,000
-$200,000
15
35
55
75
95
115
Net Financial Impact (pa)
O&M Cost ($/KWe pa)
Number of RERT Events
1 X 6h RERT
1 X 3h RERT
4 RERT Events Preactivated
2 RERT Events Preactivated
e)
$50,000
$0
-$50,000
-$100,000
-$150,000
-$200,000
15
35
55
75
95
115
Net Financial Impact (pa)
O&M Cost ($/KWe pa)
$50
$0
-$50
32
34
36
38
Gas Prices
100% ($11.56/GJ)
200%
400%

Figure 14: Net Financial Impact of participating in RERT events, when the following are varied: a site's a) generator capacity, b) generator efficiency, and c) generator usage/ load, d) number of RERT events in a year, and e) gas prices.

5.3.3 Results – WDRM Events

Two different revenue models (contract capacity agreement, and spot price share) were considered when determining the net financial impact of participating in WDRM events.

WDRM Events – Revenue Models	
Contract Capacity Agreement	
$\boldsymbol{WDRM\ Revenue} = \boldsymbol{Capacity\ Rate}\ (\$/\boldsymbol{MW}) \times \boldsymbol{Capacity}\ (\boldsymbol{MW}) + \boldsymbol{Dispatch\ Rate}\ (\$/\boldsymbol{MWh}) \times \boldsymbol{Capacity}\ (\boldsymbol{MW}) \times \boldsymbol{Dispatch\ Duration}(\boldsymbol{h})$	In this revenue model, the site agrees to provide a certain magnitude of demand response when called upon by the third-party service provide. The site receives an annual payment (even if there are no events) and payment for participating in the event. The rate for participation (Dispatch Rate) is a fixed value and does not vary with the spot price.
Spot Price Share	
$\boldsymbol{WDRM\ Revenue} = \boldsymbol{Spot\ Price}\ (\$/\boldsymbol{MWh}) \times \boldsymbol{Spot\ Price\ Share}\ (\%) \times \boldsymbol{Capacity}\ (\boldsymbol{MW}) \times \boldsymbol{Dispatch\ Duration}(\boldsymbol{h})$	In this revenue model, the site participates in an event and receives a share of the spot price at the time of participation. The Spot Price Share (%) is agreed upon with the third part service provider. The site does not receive any payments if they do not participate in an event.

The results shown are based on the following assumptions and parameters:

For the spot price share revenue model:

- $Spot\ Price\ (\$/MWh)$: \$2500, \$5000, and \$10,000 per MWh dispatched
- Spot Price Share: 50%

For the contract capacity agreement revenue model, the following were assumed:

- The site receives a Capacity Rate of \$50,000 per MW of contracted capacity per year
- The dispatch rate is \$250 per MWh.

For both revenue models, the following were assumed:

- Cumulative duration of dispatch events in a year: 0 – 40 h per year, with 4 h used as the default.
- Generator capacity: 0.5 MW or 1 MW, with 1 MW used as the default.
- The generator is operated at full capacity (100% utilisation).

Spot prices and annual dispatch durations used were based on the average spot price and cumulative duration that spot prices exceeded a specific threshold value in 2019. Further details and discussion are provided in Appendix B.

Figure 15 summarises the annual costs, savings and revenue when a 1 MW co/trigen system is operated in response to WDRM events. The results shown are based on parameters that a building with a co/trigen system may expect to experience. Operating the generators in response to such events leads to a positive net financial impact when the combined savings and revenue exceed the combined cost of generator fuel and co/trigen O&M cost. Figure 15 reveals that the co/trigen O&M significantly contributes to the total cost. In most of the scenarios considered in Figure 15, the combined savings and revenue is lower than the total cost, indicating that operating co/trigen generator solely for participation in WDR events is unlikely to be financially beneficial.

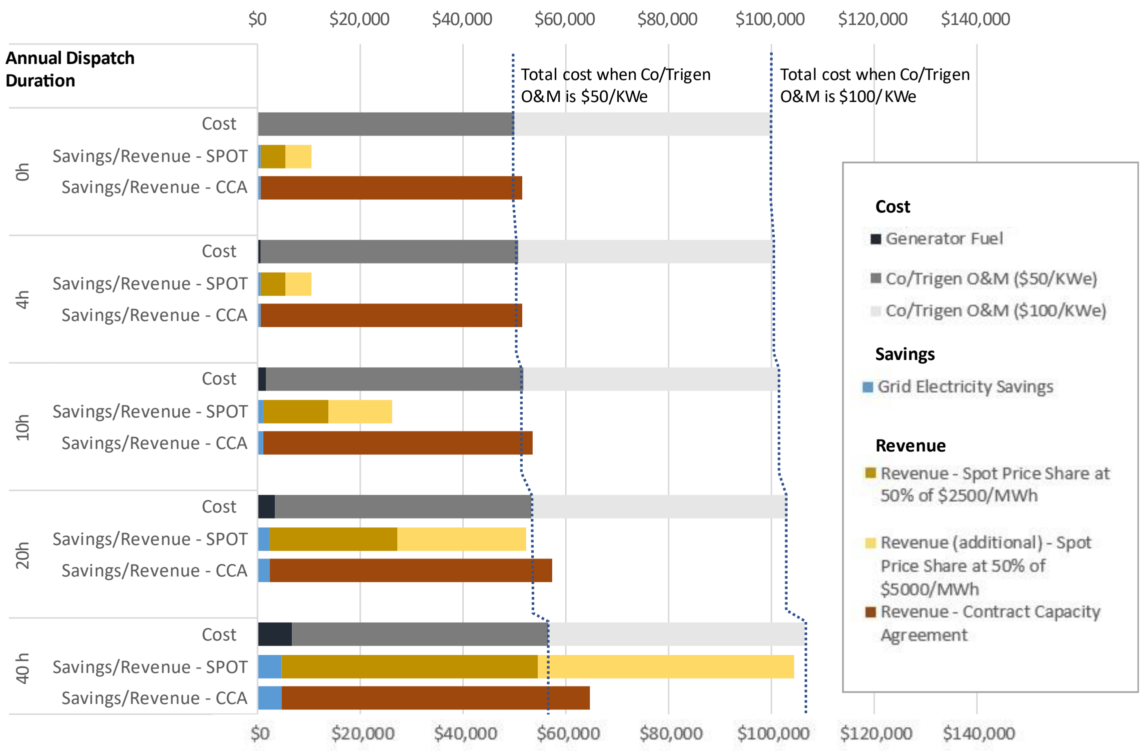


Figure 15: Annual cost, savings and revenue when a 1MW co/trigen system is operated in response to WDR events. Revenue from Contract Capacity Agreement (CCA) and Spot Price Share (SPOT) revenue models are shown.

The net financial impact of using a 0.5 MW or 1 MW generator to participate in the wholesale demand response market is shown in Figure 16. The revenue from RERT events, specified in Equation 4, are equated to zero. It was assumed that there were 4 h of dispatch in the year. As expected, results indicate that when the co/trigen O&M cost is lower, the likelihood of operating the generators with a net financial benefit is higher.

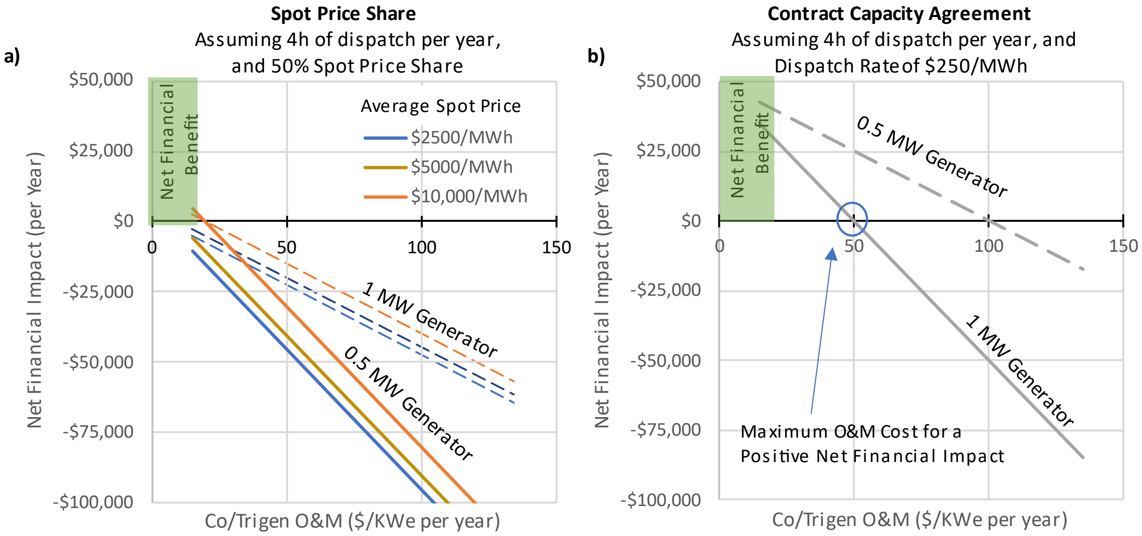


Figure 16: Net financial impact of only participating in Demand Response Events, with revenue derived from a) a spot-price share system, and b) a Contract Capacity Agreement revenue model.

As with previous results, there is a maximum co/trigen O&M for which operating the generators will be financially beneficial. Figure 17 shows how the maximum co/trigen O&M[24] cost varies with the annual dispatch duration, average spot price, generator efficiency (Figure 17a and b), gas prices (Figure 17c and d) and size of the generator. Collectively, the results reveal the following findings:

- Participating in WDR events via the spot price share revenue model is most advantageous if there is certainty that the annual dispatch duration will exceed a value, and the O&M cost is sufficiently low (Figure 17a). Under the spot price share model, revenue increases with the annual dispatch duration (influenced by the duration of individual events and the number of events) and the spot price. Consequently, a site with a higher O&M cost will require longer annual dispatch durations and/or a higher average spot price to realise a positive net financial impact. This is reflected in Figure 17a as higher maximum O&M costs.

- The contract capacity agreement method is attractive from the perspective that there is a lower risk of realising a negative net financial impact. This arises because there is a guaranteed revenue (based on the contracted capacity) even if the site is not called on to participate in any event (Figure 17b). However, the revenue attained via the contract capacity agreement model will be lower than that of the spot price share model in situations where the high annual dispatch duration is large (e.g. greater than approximately 10 h if a site has a 1 MW generator, and participates in events where the average spot price is $10,000 per MWh). This is attributed to the additional revenue earned from dispatching being less than the revenue attained via the spot price share revenue model (reflected as smaller gradient trend lines in Figure 17b compared for Figure 17a).

- Participating in WDRM events via the contracted capacity agreement is financially more beneficial that participating via the spot price share revenue model. This is a direct consequence of the two findings specified above. Based on historical spot prices (see Appendix B.1), it is unlikely that the combination of long annual

[24] Determined as the co/trigen O&M when the Net Financial Impact equates to zero.

dispatch durations and high average spot prices will eventuate; for example, in 2021, the cumulative duration when spot prices exceeded \$400 per MWh was less than 10 h, and the average spot price was approximately \$2500 per MWh.

- Higher gas prices require a site to have lower co/trigen O&M costs, and a substantial escalation in gas prices will not favour the operation of the gas generators. When participating via the spot price share revenue model, a site with higher O&M cost will need to participate in more events to overcome higher gas prices. This strategy also applies to sites that are on the contract capacity agreement, if the gas price increases but remains below \$13 per GJ. Under the contracted capacity agreement revenue model, a further increase in gas price increases the risk of a negative net financial impact as shown in Figure 17d.

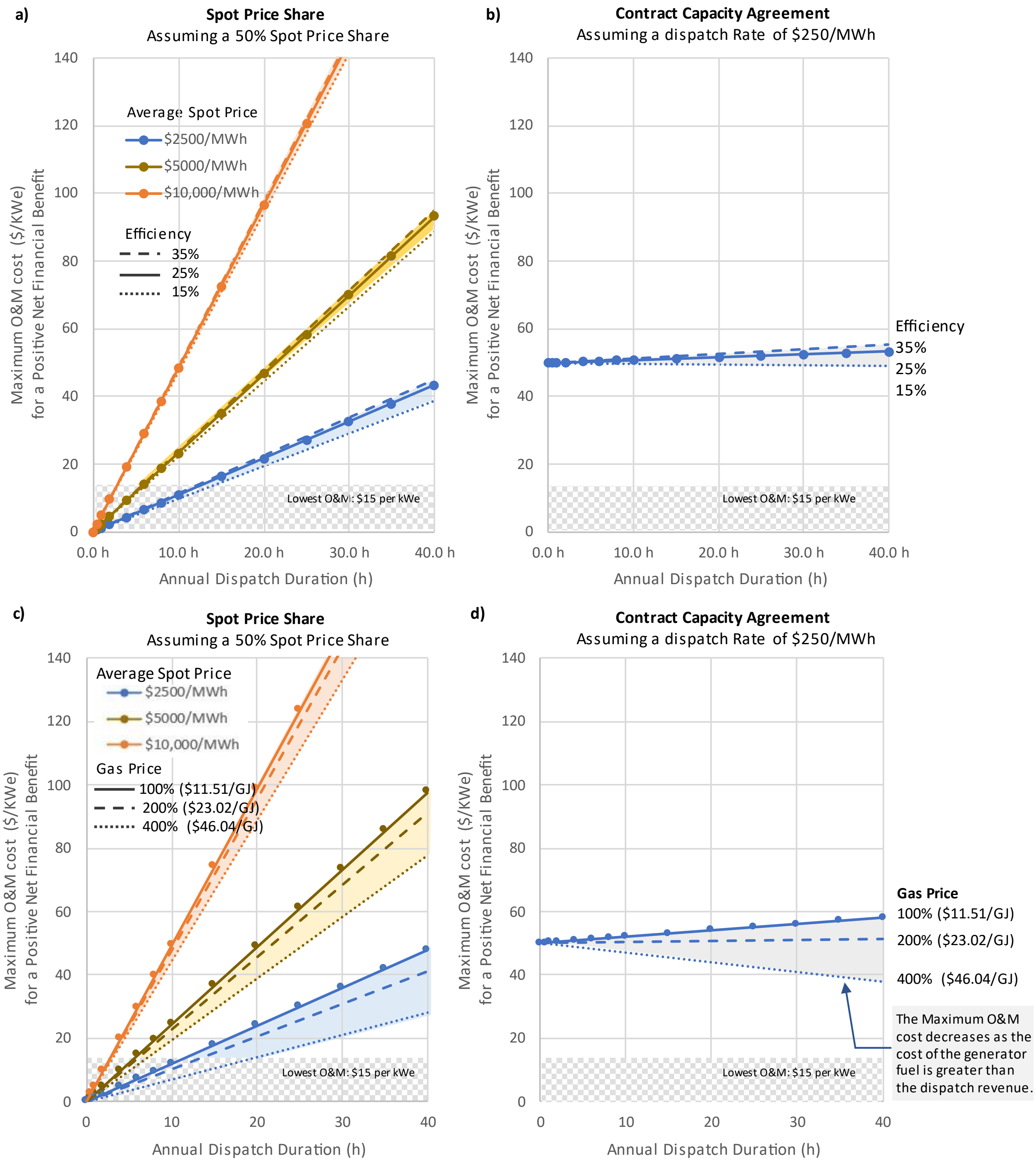


Figure 17: Maximum O&M Cost for a site participating in WDRM events via the (a and c) spot price share revenue model and (b and d) contract capacity agreement revenue models (which has a base annual payment).

Figure 17 Additional Description: The allowable O&M cost generally increases as the annual dispatch duration increases, as the average spot price increases (subplots a and c). The O&M cost allowed is lower for a site with a lower efficiency generator or has a higher gas price (c and d).

5.3.4 Results – Participation in both RERT and WDRM events

In this section, the net financial impact of participating in both RERT and WDRM events is considered. Figure 18 summarises the annual costs, savings and revenue when a 1MW co/trigen system is operated in response to both WDRM and RERT events.

Figure 18 reveals that the combined savings (avoided costs) and revenue from participating in both WDRM and RERT events is closer to, and at times exceeds, the cost of running the generators compared to the case where a site only participates in one type of grid event (either RERT or WDR events). The highest O&M cost ($/KWe) a site can have to realise a positive net financial impact, for the combination of RERT and WDRM events considered in Figure 18, are shown in Table 5. As expected, the maximum O&M costs are higher when a site participates in both WDRM and RERT events. This is attributed to the opportunity to obtain two different revenue streams to counter the high O&M cost of the co/trigen system. The results clearly show that a site should consider participating in both RERT and WDRM events, rather than only one type of event as this increases the changes of achieving a positive financial return.

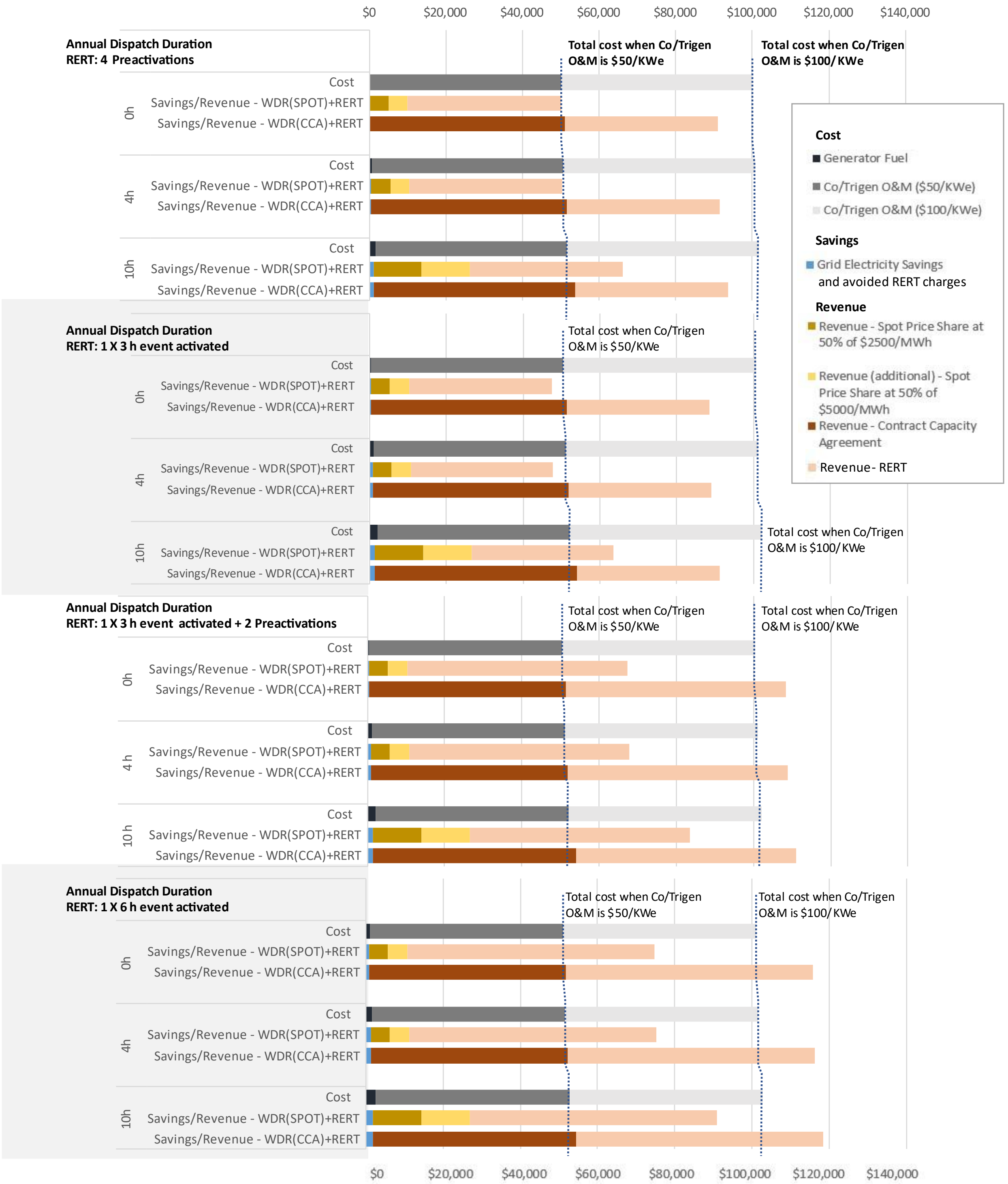


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Figure 18: Annual cost, savings and revenue when a 1MW co/trigen system is operated in response to WDR and RERT events. Revenue from WDR events based on the Contract Capacity Agreement (CCA) and Spot Price Share (SPOT) revenue models are shown.

Table 5: Maximum O&M Cost ($/KWe) for a positive Net Financial Impact if a site either participates in WDR events only, or RERT events only, or both WDR and RERT events.

		No WDRM Revenue	WDRM (SPOT)			WDRM (Contracted Capacity Agreement)		
			0h	4h	10h	0h	4h	10h
No RERT Revenue		$0.00	$10.00	$9.80	$24.49	$51.00	$51.46	$53.65
RERT event	4 Preactivation Events	$40.00	$50.00	$50.26	$65.64	$91.00	$91.26	$93.14
	1 X 3h Activated Event	$37.00	$47.29	$47.55	$62.93	$88.29	$108.55	$110.43
	1 X 3 h Event activated + 2 Preactivation Events	$57.00	$67.29	$67.55	$82.93	$108.29	$108.55	$110.43
	1 X 6 h Event Activated	$63.21	$74.59	$74.84	$90.23	$115.59	$115.84	$117.73

5.3.5 Discussion

The financial impact of operating the gas-fired generators in response to grid demand events is influenced by, and sensitive to, multiple variables, including:

- revenue from participating in the events,
- the cost incurred to operate and maintain the cogeneration/trigeneration system,
- savings from avoided costs (grid electricity consumption costs and avoided grid event charges; RERT charges), and
- the cost of generator fuel.

Our analysis found that the two most significant factors were the revenue and the operation and maintenance cost of the cogeneration/trigeneration system. Two different revenue streams were investigated – participation in RERT events, and WDR events.

- For a site that only considers participating in WDR events, it should consider utilising as much of the generator capacity as possible, as this increases the amount of revenue it can attain.
- If a site only participates in WDR events, there are two revenue models available. The spot price share revenue model was found to be less favourable than the contracted capacity model, and our analysis reflected that the end-user needs to receive more than $500 per MWh (product of the Spot Price ($/MWh) and Market Share (%)) before there is a chance that a net-positive financial outcome can be realised. The stated price threshold increases when gas prices and the generator O&M cost increase.

Results shown in sections 5.3.2 and 5.3.3 indicate that if a site only considers participating in one type of market event (WDR or RERT), it needs to participate in a relatively large number of events (or for long annual durations) in order to operate with a net positive financial outcome.

However, as RERT and WDR events operate via different market mechanisms, it is possible for a site to participate in both types of events. This opportunity enables a site to subscribe to two different revenue streams, increasing the possibility of recovering the cost of operating and maintaining the co/trigen system, and consequently operating with a net positive financial outcome (refer to Section 5.3.4).

5.4 Environmental Impact

The environmental impact of the site can be assessed by directly comparing the emissions intensity of electricity generated by the gas-fired generator with the grid emissions intensity. Figure 19 and Figure 20are graphical representations of the probability that of the real-time grid emissions being greater than the emissions from a gas generator of specific efficiencies. Graphs in Figure 19 show the probability of instances when grid-level demand response events have occurred (RERT events, and when WDRU have been dispatched), and for times between 1 March 2021 - and 31 April 2022 when there were no events. In Figure 20, shows the same probability, but does not distinguish between the types of events. The annual grid emissions intensities obtained from the National Greenhouse Accounts Factors (11), are also shown.

The emissions intensity of a gas generator (reflected in Figure 19 and Figure 20 as vertical lines) varies depending on the generator's efficiency and its location; the latter occurs as the emissions intensity of gas differs marginally for each state/territory (11).

In general, the real-time emissions intensity of the grid during demand management events is lower than the annual average (Figure 19). This reduces the probability that the operation of a gas generator generates electricity at a lower emissions intensity than the grid during such events. Indeed, in general, gas generator operation is likely to be detrimental in terms of real-time emissions. Exceptions to this are for generators in NSW, QLD and VIC, where the generators have an efficiency higher than 30%, 26% and 22%, respectively. At these efficiencies, there is a 50% probability that the generator's emissions intensity is lower than the real-time emissions[25].

From a site perspective, the emissions intensity is judged from the perspective of average annual emissions factors which, being higher than the event-specific factors, are generally favourable for the use of the generator. This effect is amplified for NABERS ratings, which are based on lagging indicators of annual emissions intensity. At the site level, emission calculations for reporting and for NABERS ratings are based on annual average emission factors. In 2022, the current state of play is:

- VIC: Gas generator operation is likely to reduce overall site emissions
- QLD, NSW, NT, and WA: Gas generator operation may reduce emissions for generators operating at efficiencies above 23%, 26%, 27%, and 29%, respectively.
- SA and TAS: Gas generator operation will increase emissions

While the real-time emissions impact of gas generator use may be detrimental, this ignores the bigger picture question of the extent to which the availability of demand-side resources enables the market to have a higher proportion of renewable energy use. Comparing the low frequency and short duration of demand response events against the year-round emissions reduction of any incremental addition to renewable generation capacity enabled by the demand management services provided, it would seem likely that the net result is strongly in favour of the use of the generator capacity.

[25] The comparison is based on real-time grid emissions between 1st March 2021 and 30th April 2022.

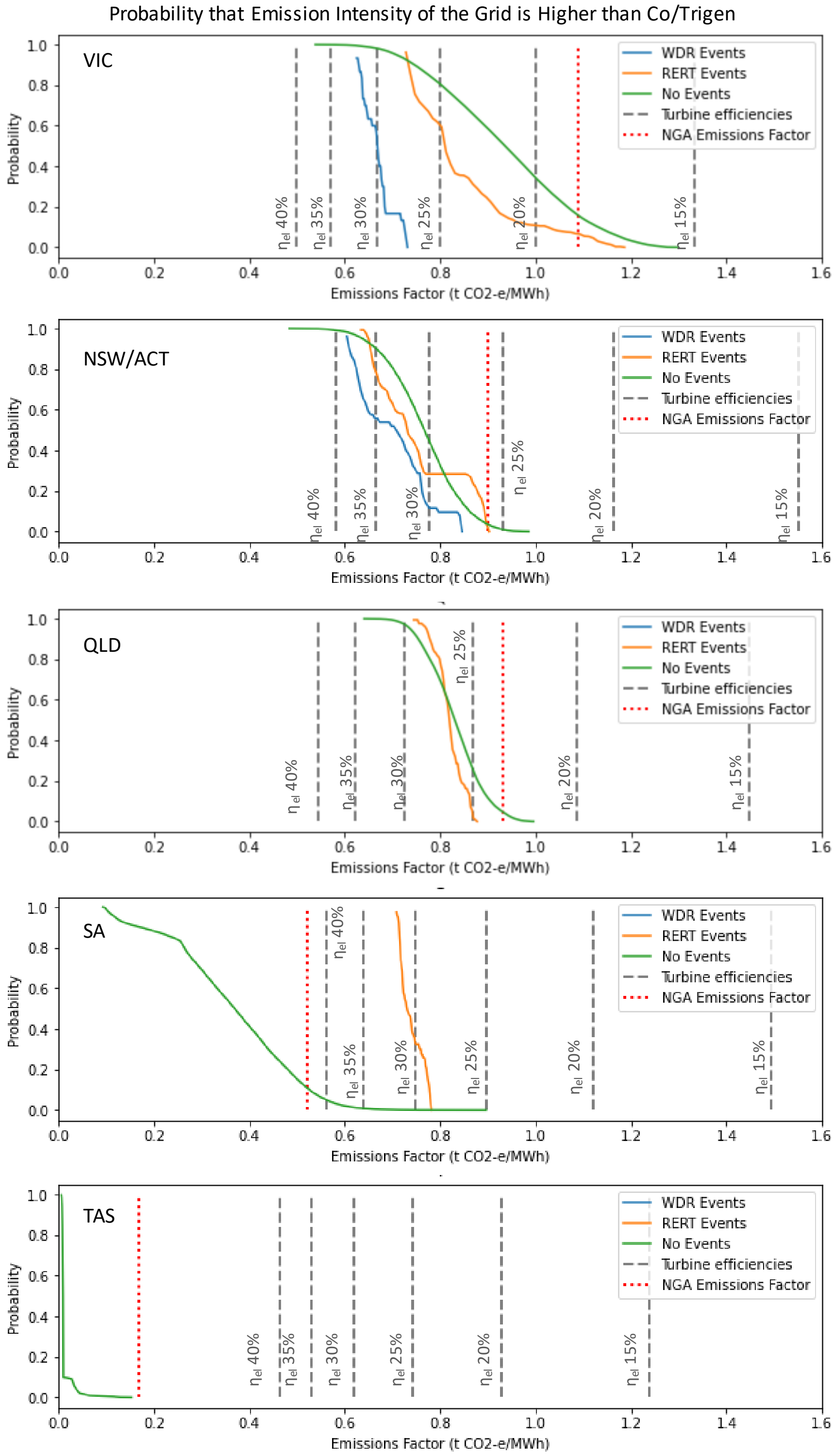

Figure 19: Grid emissions probability graph with emissions factor for gas engine generators with different electrical efficiencies (15 – 40%) indicated.

Figure 19 can be used to visually assess the likelihood that using the gas-generators will lead to less CO2-e emissions being released than consuming grid electricity. It serves as a visual aid for determining the environmental impact and impact on the NABERS ratings.

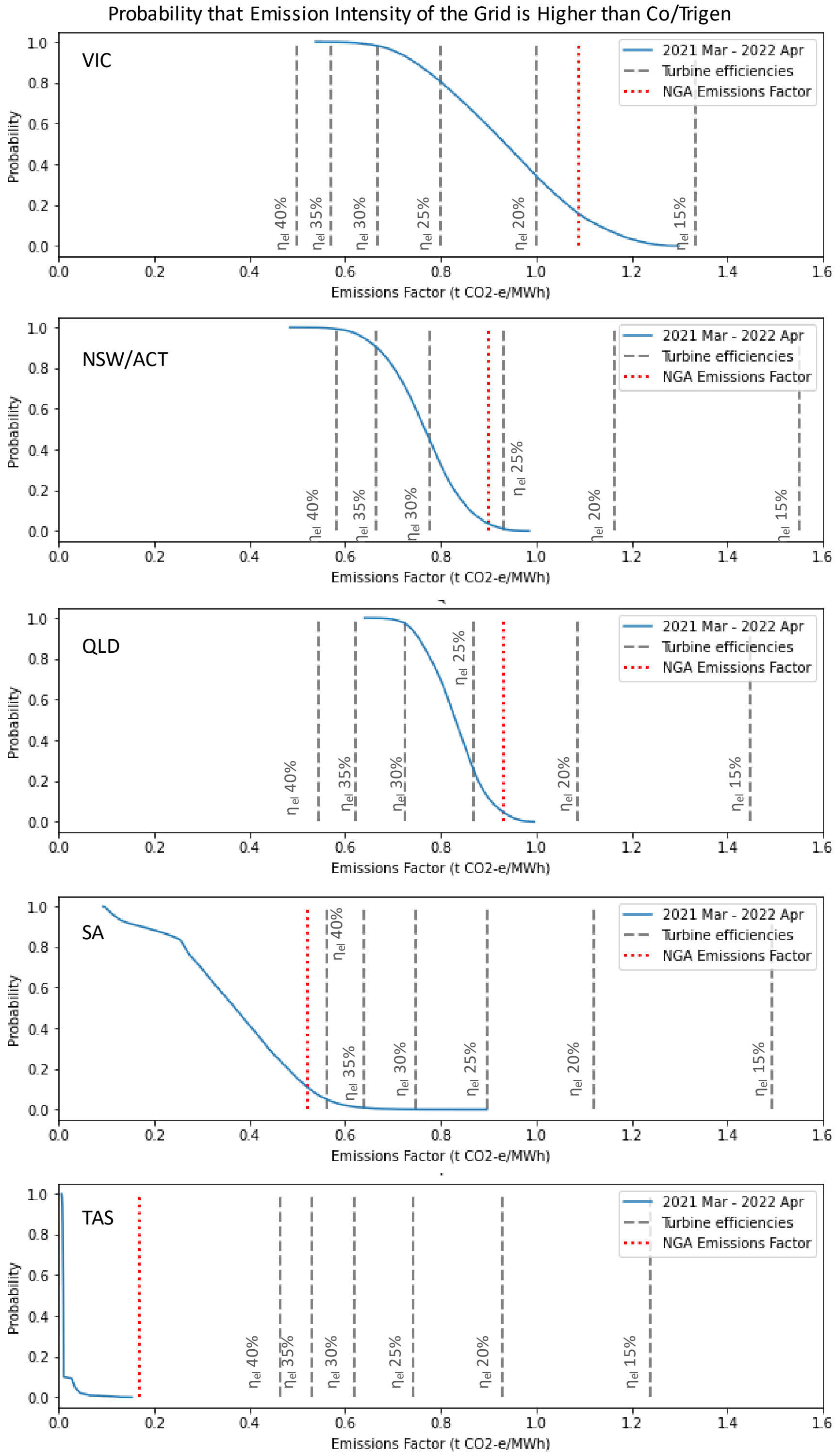

Figure 20: Grid emissions probability graph with emissions factor for gas engine generators with different electrical efficiencies (15 – 40%) indicated.

Figure 20 can be used to visually assess the likelihood that using the gas-generators will lead to less CO_2-e emissions being released than consuming grid electricity. It serves as a visual aid for determining the environmental impact and impact on the NABERS ratings.

6 Additional Considerations

6.1 Switching from Natural Gas to Bio-Gas

The combination of high natural gas prices, and emissions associated with the combustion of natural gas creates an incentive for switching over to biogas. The effects of running bio-gas in gas generators have been published in the literature and are covered in section 1.2 of this report.

6.1.1 Supply and Cost

There is currently a trial scheme to sell biogas across the gas network, similarly to how Green Power is sold on the electricity network. The financial implication of using this opportunity to switch from natural gas to (reticulated) biogas is currently unknown due to uncertainty in the retail price of biogas[26]. However, the approach described in the early sections (Section 4 and Section 5) can be used to determine if it is cost-beneficial, i.e. To estimate if using bio-gas is cost beneficial, adjustments to the price of generator fuel ($/GJ) and the electricity generation efficiency of generators should be made. The cost of biogas could be obtained from retailers at a future date, while the electricity generation efficiency could be estimated at 2% lower than the efficiency of the generator when natural gas is being consumed.

6.1.2 Environmental Impact

The emissions factors associated with the use of natural gas and biogas, published by the NGA are compared shown in Table 6 (11), noting that scope three emission for bio-gas is not readily available. On average, and based on the emissions factors shown Table 6, the emissions factor for using biogas can be estimated to be approximately ten times lower than that of natural gas. The significant reduction in emissions factor outweighs the larger volume of gas required to produce one unit of electricity.[27] Consequently, switching from natural gas to biogas will make the emissions intensity lower than the average grid emissions intensity across all states and territories because the emission factor for using biogas is approximately 10 times lower than that of natural gas.

Table 6: Natural gas and bio-gas emissions factors (11).

State	Natural Gas (Kg CO_2-e/GJ)			Bio Gas (Kg CO_2-e/GJ)		
	Scope 1*	Scope 3^	Scope 1 – 3	Scope 1*	Scope 3	Emissions Factor Used for comparison
NSW & ACT	51.53	13.10	**64.63**	6.43	N/A	**6.43**
VIC	51.53	4.00	**55.53**	6.43	N/A	**6.43**
QLD	51.53	8.80	**60.33**	6.43	N/A	**6.43**
SA	51.53	10.70	**62.23**	6.43	N/A	**6.43**
WA	51.53	4.10	**55.63**	6.43	N/A	**6.43**
TAS	51.53	N/A	**51.53**	6.43	N/A	**6.43**
NT	51.53	N/A	**51.53**	6.43	N/A	**6.43**

#Scope 2 and 3 emissions factors – consumption of purchased
* Emissions Factors for the consumption of gaseous fuels
^Scope 3 emission factors – natural gas for a product that is not ethane (inclusive of coal Metro areas).

[26] Potential Bio-Gas retailers approached were unable to provide expected retail prices for piped bio-gas.
[27] Due to (1) the lower energy density (MJ/m^3) of biogas, and (2) the marginal (<2%) reduction in electrical and thermal recovery efficiencies of generators that use biogas compared to natural gas (See section 1.2 for references)

6.2 Operation of Heat Recovery During Demand Response Events

In co/trigen systems, the ability to use the waste heat for space heating and cooling (via the absorption chiller in a trigeneration system) is a key advantage over sites with a stand-alone gas generator. The decision to operate the heat recovery components of co/trigen systems during demand response events depends on the following:

- Thermal response time for heat recovery: There is a time delay from when the generators are operational to when the effects of heat recovery are observed.
- Time of day that the event occurs: the event needs to occur when there is heating and/or cooling demand in the building. For commercial office buildings, heating and cooling loads occur during business hours on business days, and the building chillers and boilers/heat pumps are operated between 6 am – 6 pm on business days.
- Demand response event duration: The duration of the event needs to be long enough for the effects of the heat recovery to be realised. At a minimum, the events need to be longer than the time constants associated with the generator fuel input to observe space heating/cooling effects in the building.
- Frequency of demand response events: the occurrence of events suitable for heat recovery operations will need to be high enough for there to be a cumulative positive benefit. Where the frequency is low, the efforts required to operate heat recovery and/or the cumulative effects of the potential benefits are little/ insignificant.

Based on the considerations mentioned above, it was found that there is little benefit in operating heat recovery or absorption chillers during demand response events in commercial office buildings for the following reasons:

1. Measured thermal response times are long: The time constant from gas input to cooling output of the absorption chiller was measured at approximately 50 minutes, which is longer than many demand response events. The operation of the absorption chiller is further discouraged from the perspective that at part load, the thermal efficiency of an absorption chiller is very low, with the result that very little chilled water is actually generated.[28]
2. Heat recovery to heating hot water had a faster response at 15 minutes, but the measured benefits were small.[29] The thermal response time for heat recovery is long relative to the expected duration of most demand response events. This, in conjunction with 1) a limited likelihood that there will be a need for heating/cooling during the demand response event, and 2) the limited number of events, does not incentivise the cost and effort required to maintain and operate the heat recovery system.
3. RERT events typically occur towards the end of the day where a commercial building has only a few hours of cooling demand left, and typically would have minimal heating load.[30] Indeed, given the average RERT event start time, of 4pm, only up to 2 hours of building operation would be expected, shorter than the 3-6 hour duration of the event. This further compromises the viability of the use of heat recovery.

[28] Analysis of the pilot study site demonstrated that at low load, absorption chiller thermal COPs could be as low as 0.2.
[29] The analysis estimated that operating the heat recovery for space heat for 1.2h, 5h and 9.3h, yielded a reduction in boiler gas consumption of 0-2%, 5% and 30% respectively, (+/- 2.5%)
[30] the average activation/ start time for RERT events was 4pm, based on events that occurred between Jan 2019 and 2022 May, across all regions in the NEM.

4. Demand response events are infrequent, and their durations are expected to be shorter than RERT events.[31]

Table 7 summarises this discussion. It indicates that due to the sporadic nature of demand response operation, there is little benefit in the operation of heat recovery or absorption chillers during demand response events. Further details of analysis performed on heat recovery, via the absorption chiller and space heating, are provided in Appendix C.

Table 7: Summary of thermal response time and estimated benefits associated with heat recovery operation during demand response events.

Heat Recovery type	Thermal response time	Benefit of operating heat recovery during the different types of events		
		Grid Event RERT	Grid Event WDR	Site Event Change in on-site renewable generation
Cooling (Absorption Chiller)	> 50 mins	No/little benefit	Unknown#	No benefit
Heating (Heat exchanger)	> 15 mins	No/little benefit	Unknown#	No benefit
# Benefit unknown due to uncertainty of event duration.				

6.3 Why focus on underutilised gas generators?

The degree to which a site can participate in the grid demand response events is limited by the site's current configuration and current grid demand. The current grid demand is used as the baseline for measuring the demand reduction during the events (19). Figure 21 shows the case of two different modes of building operations, one where the site is currently using the co/trigen system to meet part of the base load during the weekdays, while the other is not. Sites with co/trigen systems that are not currently operating to supply part of the base load are better placed, as the magnitude that the site's grid demand can be reduced is greater (reflected in the length of arrows in Figure 21).

Based on the site's baseline grid demand, it may not be possible to use all the co/trigen capacity at that site. If the site's baseline grid demand is smaller than the co/trigen capacity, then only a proportion of the co/trigen system's maximum capacity can be used. The percentage of usable capacity is captured as the 'Usage Capacity' in the analysis in previous sections (Section 4 and Section 5).

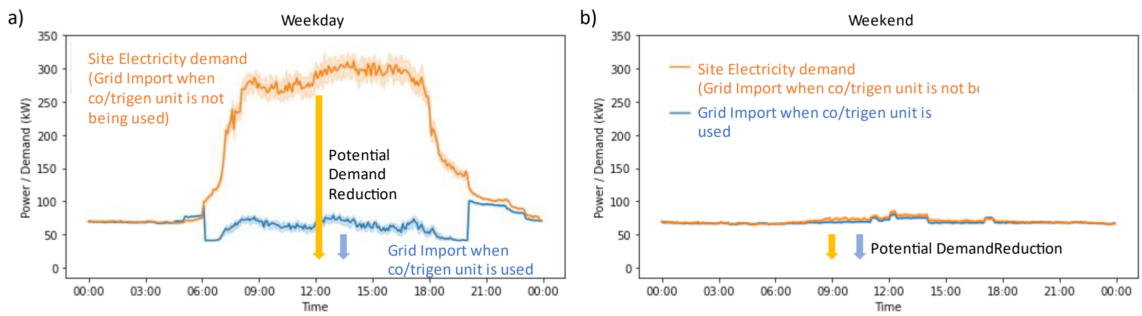

Figure 21: Average daily load profile (grid import) for the pilot study office building during (a) weekdays and (b) weekends.

[31] Uncertainty in the duration of the demand response events arises from 1) the Wholesale Demand Response Mechanism is relatively new, commencing in October 2021 and the number of events that have occurred is limited (2 times between Oct 2021 and April 2022); 2) the two events to date have been shorter than RERT events, and 3) the duration is variable as depends on settings selected by the demand responder.

7 Conclusion

The feasibility and impact of using under-utilised gas-fired generators in commercial buildings have been investigated. The objectives of the sub-project were investigated through consultations with third parties that provided demand response services, reviewing the installed cogeneration and trigeneration capacity, and analysing the electricity market data and data from a pilot study site. The pilot study site had both on-site renewable energy generation and an operational trigeneration system.

The review of the installed cogeneration and trigeneration capacity found that in the past 20 years, at least 120 MW (electrical) of cogeneration and trigeneration capacity has been installed in buildings (commercial, office towers, retail and residential), hospitals, and recreational facilities and precincts. In the built environment, the largest co/trigen capacities are likely to be in hospitals, followed by data centres, airports, and office buildings. The current status of these installations varies. Some sites use them to provide base load, while others either already have, or plan to, switch off or decommission the cogeneration/trigeneration systems. The operation of gas generators for demand management is best suited to generators that are not operated for underlying site demand.

Key findings from this project include:

- Operating gas generators to only meet the short-term changes in on-site renewable generation output is unlikely to cover the O&M costs for the generator.
- Achievement of a positive financial return from operating the gas generators requires, essentially, all demand management revenue streams to be captured due to the high O&M costs for generators
- The net real-time environmental impact of gas generator operation is generally negative. However, the impact on NABERS ratings is more generally positive, and it is expected that the holistic impact allowing for increased connection of renewable energy to the grid enabled by greater demand response capacity would be strongly positive.

Strategies for operating the gas generators (from cogeneration and trigeneration systems) in response to site-level and grid-level events have been developed and reported. The financial and environmental impacts have also been assessed. Finally, a Building Owners' Guide has been developed (Appendix D); it guides building owners with co/trigen units through a series of steps enabling them to decide if they should further consider operating the co/trigen systems as demand response units.

In terms of future opportunities, while the results indicate potential financially viable demand response is available from this subsector, it is noted that building owners are currently decommissioning these systems because the financial and environmental case they were built for is evaporating. Thus, the window of opportunity is closing rapidly, and timely intervention would be needed to capture the full potential benefit to the grid. Meantime, our discussions with demand response aggregators indicated that classic building demand response – in terms of the wind back of HVAC power demand – is largely untouched due to the perceived and real risks and complexities associated with the potential to create occupant discomfort. The development of a means of quickly characterising the quantity, duration and response rate of available load reduction could significantly speed the access of the grid to this significant resource.

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Appendix A – Model Parameters

A.1 Economic Parameters/Values

To determine whether utilising the gas-fired generation results in a net economic benefit, the following items were considered;

- Cost of Fuel (Natural Gas)
- Cost of operating and maintaining the co/trigen plant
- Grid electricity savings – reduction in volume of energy consumed (kWh)
- Grid electricity savings – Savings from avoided peak demand (kW or kVA)
- Additional revenue from participating the demand response event.

Cost of Electricity and Fuel

The cost of fuel, and grid electricity savings were estimated using the prices in the gas and electricity utility bills. The following values were applied in the analysis. Prices listed include retail, network, market and environmental charges, and takes into consideration a loss factor of 1.04. A power factor of 0.9 is assumed.

Table 8: Utility prices used in the analysis

Utility Type	Value/ Charge	Charge
Grid Electricity	Energy Consumption at Peak Periods	14.16 cent/kWh
	Energy Consumption at Off-Peak Periods	8.79 cents/kWh
	Monthly Peak Demand	12.12 $/kVA/month
Natural Gas	Consumption Charge	11.509 $/GJ
Bio-Gas	Consumption Charge	23 $/GJ

Co/trigen Operations and Maintenance (O&M)

Table 9: Co/trigen systems based on different generator types, the overall capital cost and operation and maintenance (O&M) cost estimates, excluding the cost of gas consumption.

Generator Type	Available Sizes (1)	Capital cost – $ AUD/kWe rated output (1)	O&M Cost ($/kWe - 2021)	
			Lower Limit (Lowest Capital Cost, O&M at 1.5% of Capex)	Upper Limit (Highest Capital Cost,O&M at 3.0% of Capex)
Reciprocating engines (Spark Ignition)	20 – 4000 kW	$800–$2500	$14.19	$88.66
Microturbines	30 – 250 kW	$1800–$3000	$31.92	$106.39

Operations and Maintenance (O&M) costs are typically expressed in terms of $/kWh. However, for the purpose of this analysis, the O&M costs are estimated and quantified relative to the co/trigen capacity.

Operating and maintenance costs of co/trigeneration systems have been reported to range between 1.5 – 3.0%[32] of the total capex cost (21). The capex cost for co/trigeneration systems vary depending on the size and type of generator used, as previously reported by (1) in 2013. These values are summarised in Table 9, with further adjustments made to account for inflation[33]. Based on these literature values and assumptions, the upper and lower limits of expected O&M costs for co/trigen systems.

The upper limits of the O&M values derived for microturbines agreed with the O&M costs for the cast study site, where the cost of maintaining the trigeneration system, was approximately $100 - $113 per kWe of trigeneration capacity (this value includes call out fees, and cost to maintain the absorption chiller).

A.2 Emissions Factors

The environmental effects of using co/trigeneration systems to participate as demand response units was assessed using carbon emissions are as quantifier. The emissions intensities were obtained or derived from two source; the National Greenhouse Accounts (NGA) Factors (23), and AEMO (24).

The NGA Factors are used in NABERS ratings (23) and updated every 5 years, with the next update of the factors used in NABERS ratings scheduled for 2025 (25). Consequently, their application in this study enables the impact that using the gas-fired generators has on a site's NABERS rating to be assessed. Where possible, this analysis uses Scopes 1, 2 and 3 emissions. The emissions factors for grid electricity consumption, natural gas consumed on-site and biogas used in this study are presented in Table 10.

Table 10: Emissions Factors used to determine the environmental impact (11).

	Grid Electricity#			Natural Gas			Bio Gas		
Units	Kg CO_2/kWh			Kg CO_2-e/GJ			Kg CO_2-e/GJ		
State	**Scope 2**	**Scope 3**	**Scope 2 & 3**	**Scope 1***	**Scope 3^**	**Scope 1 – 3**	**Scope 1***	**Scope 3**	**Emissions Factor Used**
NSW & ACT	0.78	0.07	**0.85**	51.53	13.10	**64.63**	6.43	N/A	**6.43**
VIC	0.91	0.10	**1.01**	51.53	4.00	**55.53**	6.43	N/A	**6.43**
QLD	0.80	0.12	**0.92**	51.53	8.80	**60.33**	6.43	N/A	**6.43**
SA	0.30	0.07	**0.37**	51.53	10.70	**62.23**	6.43	N/A	**6.43**
WA	0.67	0.01	**0.68**	51.53	4.10	**55.63**	6.43	N/A	**6.43**
TAS	0.14	0.02	**0.16**	51.53	N/A	**51.53**	6.43	N/A	**6.43**
NT	0.54	0.04	**0.58**	51.53	N/A	**51.53**	6.43	N/A	**6.43**
#Scope 2 and 3 emissions factors – consumption of purchased * Emissions Factors for the consumption of gaseous fuels ^Scope 3 emission factors – natural gas for a product that is not ethane (inclusive of coal Metro areas).									

[32] *"These costs are often covered by full service/maintenance contracts that account for the cost of rectifying faults, including spare parts, and include personnel and travel costs during the agreed period. As part of a full maintenance contract, regular maintenance is normally carried out by the service provider."* (21) It is assumed that the reported percentage reported by (21) also encapsulates the cost of maintaining absorption chillers in trigeneration systems.

[33] Inflation was accounted for by multiplying the 2013 prices by a factor of 1.182, sourced from the Reserve Bank of Australia Inflation Calculator for inflation rates between 2012 and 2021 <https://www.rba.gov.au/calculator/annualDecimal.html> (Accessed on 20 May 2022).

The NGA Factors are annualised values and do not reflect changes in the emissions intensity of grid electricity throughout the day or year. To determine the 'real time' impact of using the gas-fired generators instead of consuming grid electricity, the grid emissions intensity at 5-minute interval periods was calculated using data published by AEMO. The following monthly historical data files, available from AEMO's Market Data NEMWEB[34] obtained and processed using a python code:

- PUBLIC_DVD_DISPATCHLOAD
- PUBLIC_DVD_DUALLOC
- PUBLIC_DVD_GENUNITS

The grid emissions intensity for each 5-minute interval period can be expressed as the following equation:

$$\frac{\sum_n D_n E_n}{\sum_n D_n} + T$$

Where

- D_n is the dispatched amount (MWh) for a dispatch unit *n* in a particular state/region, for each time interval. This information is available from PUBLIC_DVD_DISPATCHLOAD
- E_n is the scope 1 emission factor for the dispatch unit *n* in a particular state/region, available from the file PUBLIC_DVD_GENUNITS
- Each dispatch unit is identified via a unique DUID number.
- T is the scope 3 emissions factors for each state, to account for transmission losses. The NGA Factors (see Table 10) values are used.

It should be noted that the generators listed in the file PUBLIC_DVD_GENUNITS are identified by GENSETIDs and not DUIDs, the latter is used in PUBLIC_DVD_DISPATCHLOAD. Consequently, the PUBLIC_DVD_DUALLOC file was used to map the GENSETIDs in one file, with the DUIDs in the other file.

A.3 PV generation profile

The PV generation profile used was based on the median solar generation from a 100 kW PV array on sunny days in December, with a 90% decrease in generation at noon for 15 minutes superimposed. It should be noted that the 90% decrease modelled is an extreme case, as this is larger than the 90th percentile PV fluctuation magnitude observed for sunny December days at the same site.

[34]Accessible via: https://visualisations.aemo.com.au/aemo/nemweb/index.html#mms-data-model

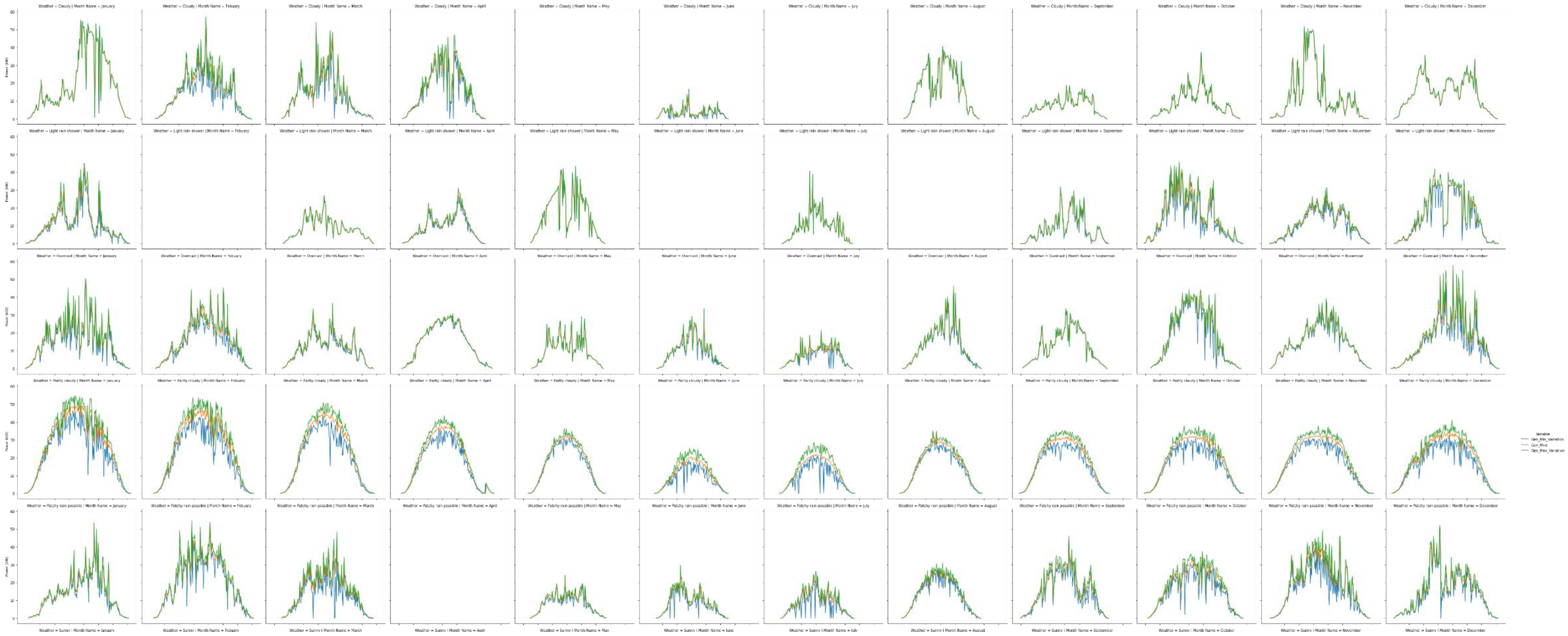

Figure 22: Median PV generation, and 90th percentile PV Fluctuations for different months and different weather conditions.

Appendix B – Electricity Market Analysis

B.1 RERT and WDR Events

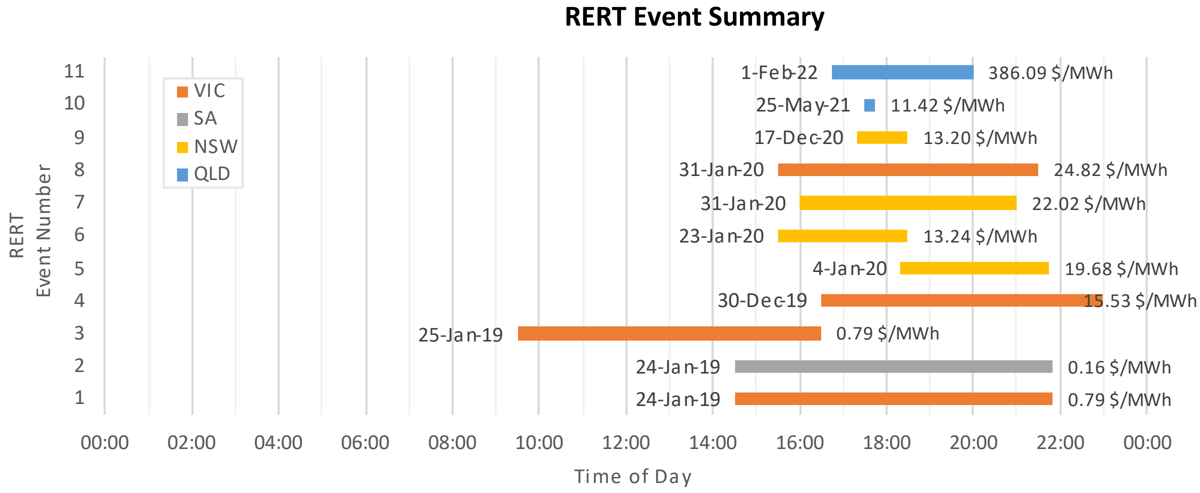

Figure 23: Summary of time and duration of RERT events that were activated between January 2019 and March 2022. The event date, start time, end time, and average Total Cost Recovery ($/MWh) as reported by AEMO are shown.

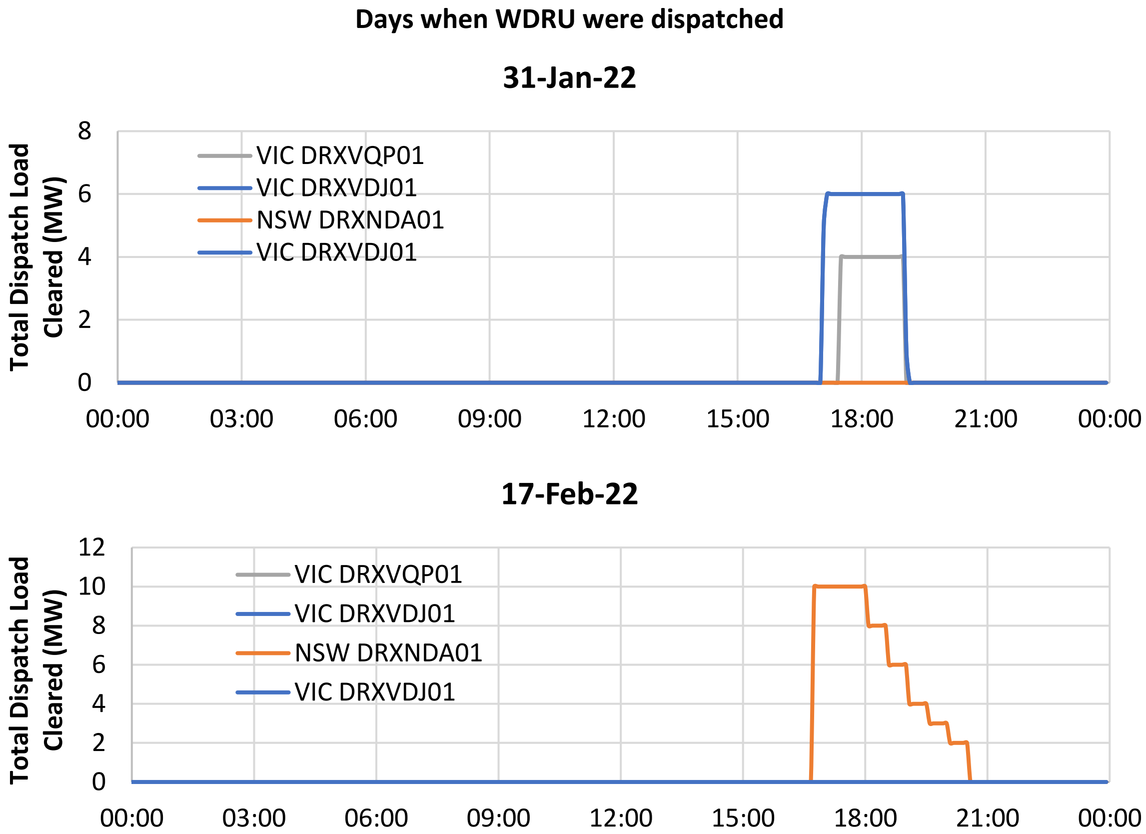

Figure 24: Duration and dispatch load associated with a WDR event in 2022. Top: Event in Victoria on 31 January 2022, bottom: event in NSW on 17 Feb 2022. Data Source: AEMO

B.1 Spot Price Analysis

The average spot price and cumulative duration that spot prices exceeded a certain value in 2019 is shown in Figure 25. As shown in Figure 25, if a site chooses to dispatch when spot prices are greater than a specific price threshold (e.g. $400 /MWh), the average spot price across all the times when the spot price exceeds the threshold is significantly higher (approximately $5000/ MWh for NSW in 2019). As the price threshold increases, the average spot price increase, but the duration available for participating reduces. Based on the results shown in Figure 25 , a range of spot prices ($2500, $5000, and $10,000 per MWh dispatched) and dispatch durations (0 – 40 h) was used in the analysis. Similar trends were observed for 2019 and 2020 electricity spot prices.

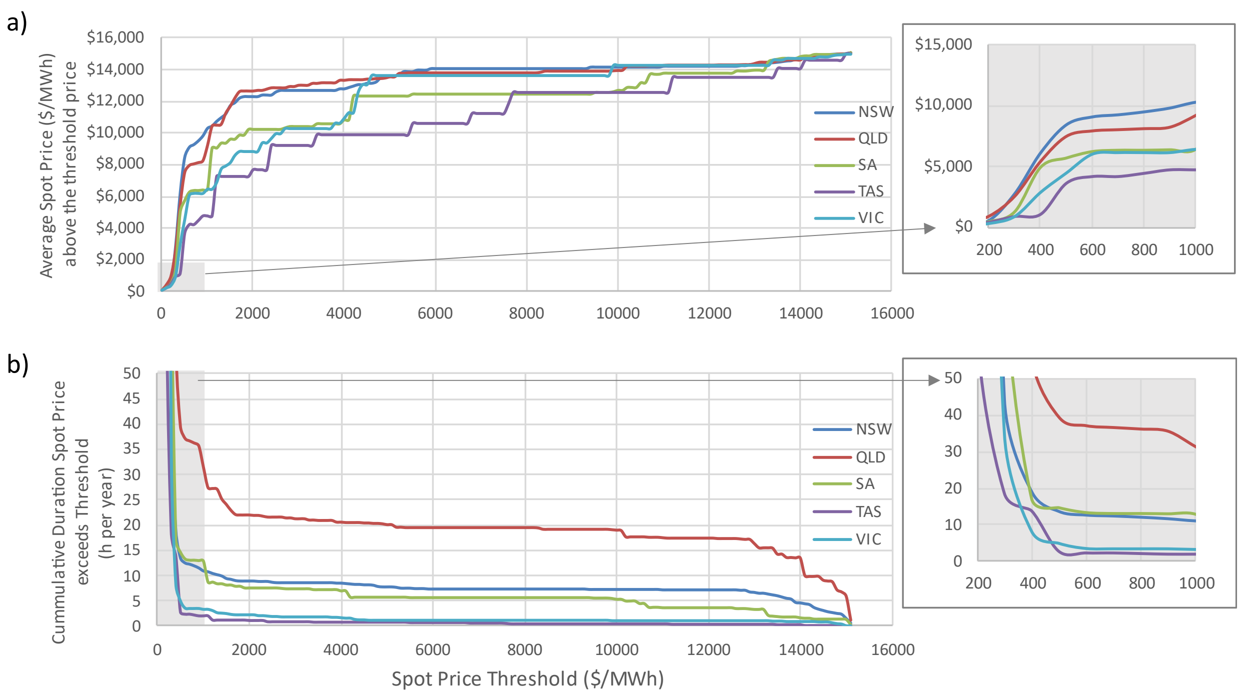

Figure 25: (a) Average spot price and (b) cumulative duration when spot prices are greater the threshold price, for 2021. (Data source: AEMO)

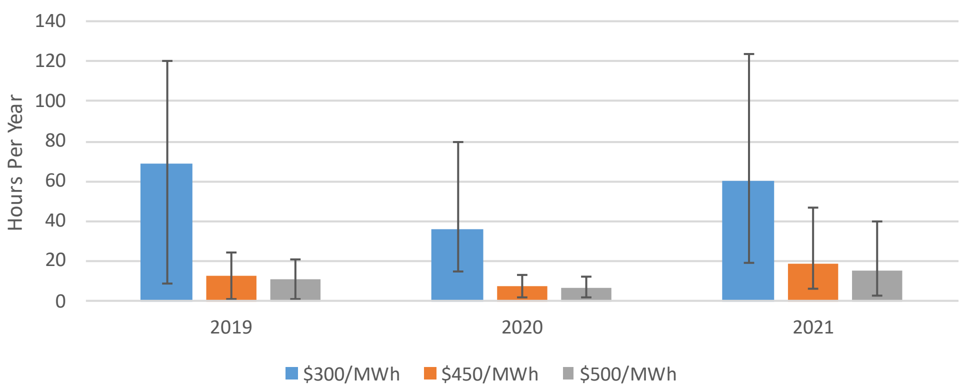

Figure 26: Number of hours per year where the spot price (averaged across the NEM) exceeded 300, 450 and 500 $/MWh. Values presented are the average across all regions in the NEM, error bars reflect the minimum and maximum number observed for each region. Analysis based on data sourced from AEMO.

Table 11: Wholesale electricity prices analysis for each region.

*Distribution of prices, percentage of time, and number of hours that pot prices were greater than 150, 300, 450 and 500 $/MWh. Spot price thresholds used are significantly higher than the usual price in the market (greater than the 90th percentile value). * Values for 2022 are based on data for January – April. Data Source: AEMO.*

		Spot Price ($/MWh)				Percentage of time that the Spot Price in greater than X $/MWh				Hours where the post price is greater than X $/MWh			
REGIONID	**Year**	**Average**	**Median**	**10th Percentile**	**90th Percentile**	**150**	**300**	**450**	**500**	**150**	**300**	**450**	**500**
NSW1	**2019**	81.5	70.8	45.7	115.0	4.46 %	0.16 %	0.01 %	0.01 %	453.2 h	15.8 h	1.0 h	0.6 h
	2020	62.4	41.7	32.3	66.5	1.62 %	0.21 %	0.15 %	0.14 %	143.8 h	18.3 h	13.2 h	12.5 h
	2021	73.3	49.1	28.9	101.7	4.84 %	0.50 %	0.18 %	0.15 %	424.4 h	44.1 h	16.0 h	13.5 h
	2022*	112.0	90.0	60.1	207.4	15.66 %	0.24 %	0.09 %	0.08 %	451.7 h	6.9 h	2.5 h	2.2 h
QLD1	**2019**	68.9	65.0	37.1	104.7	2.59 %	0.08 %	0.02 %	0.01 %	263.6 h	8.3 h	1.6 h	1.5 h
	2020	41.7	37.6	18.8	60.7	1.16 %	0.17 %	0.09 %	0.09 %	102.8 h	14.9 h	7.8 h	7.7 h
	2021	89.5	45.7	18.5	115.3	6.37 %	1.42 %	0.54 %	0.45 %	558.2 h	124.0 h	46.9 h	39.6 h
	2022*	167.1	101.7	60.6	277.0	21.67 %	6.95 %	1.07 %	0.98 %	625.1 h	200.4 h	30.9 h	28.2 h
SA1	**2019**	80.6	78.0	19.8	131.5	5.92 %	1.19 %	0.22 %	0.20 %	601.0 h	120.6 h	22.2 h	20.0 h
	2020	42.1	41.7	4.6	69.0	2.13 %	0.90 %	0.06 %	0.04 %	188.6 h	79.8 h	5.5 h	3.8 h
	2021	50.7	39.2	-31.1	109.2	4.61 %	0.89 %	0.18 %	0.17 %	404.0 h	77.8 h	15.6 h	14.6 h
	2022*	90.9	77.4	-33.9	204.6	15.17 %	2.39 %	0.21 %	0.18 %	437.5 h	68.8 h	5.9 h	5.3 h
TAS1	**2019**	91.0	90.5	23.0	138.2	5.51 %	0.83 %	0.14 %	0.12 %	559.3 h	84.3 h	13.9 h	12.0 h
	2020	42.9	40.0	11.3	68.3	1.01 %	0.49 %	0.02 %	0.02 %	89.7 h	43.8 h	2.2 h	1.9 h
	2021	33.6	30.1	-0.7	58.7	1.03 %	0.21 %	0.12 %	0.03 %	90.4 h	18.7 h	10.2 h	2.8 h
	2022*	87.6	72.1	30.8	162.0	12.68 %	0.39 %	0.08 %	0.01 %	365.8 h	11.3 h	2.3 h	0.3 h
VIC1	**2019**	108.2	85.8	34.6	133.2	6.92 %	1.13 %	0.24 %	0.21 %	702.9 h	115.2 h	24.7 h	20.8 h
	2020	54.7	41.5	9.2	70.0	1.53 %	0.25 %	0.10 %	0.09 %	135.6 h	22.2 h	8.6 h	8.3 h
	2021	44.9	34.4	-17.9	94.2	4.05 %	0.40 %	0.07 %	0.06 %	355.0 h	34.9 h	6.2 h	5.1 h
	2022*	77.8	70.1	-3.5	174.6	12.50 %	0.19 %	0.06 %	0.05 %	360.5 h	5.4 h	1.7 h	1.5 h

Heat Recovery via the Absorption Chiller:

An assessment of data from the pilot study site indicated that the time constant from gas input to the generator to cooling output from the absorption chiller at start-up is of the order of 50 minutes. This long response time makes RERT events the main candidate event for operating the absorption chiller. However, the heat recovery system would only need to be operated for a limited number of hours (1-2 hours). The limited opportunity/duration of operating the absorption chiller is shown in Figure 27, which overlays a building cooling demand and the duration of the RERT event. The operation of the absorption chiller is further discouraged from the perspective that at part load, the thermal efficiency of an absorption chiller is significantly lower than the electrical efficiency of a compression chiller (Figure 28).

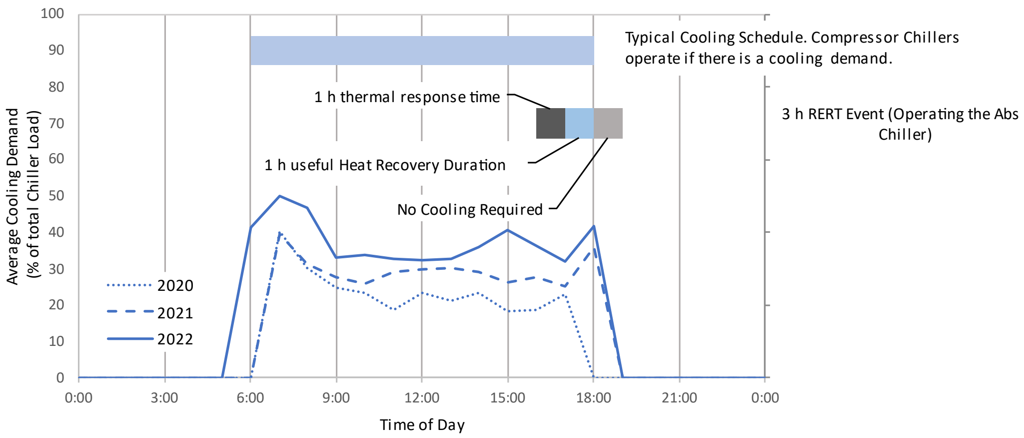

Figure 27: Average cooling demand of the pilot study site building during a business day, compared with the typical plant operational hours and the short durations that co/trigen heat recovery could operate generators responded to a 3hr RERT event starting at 4pm.

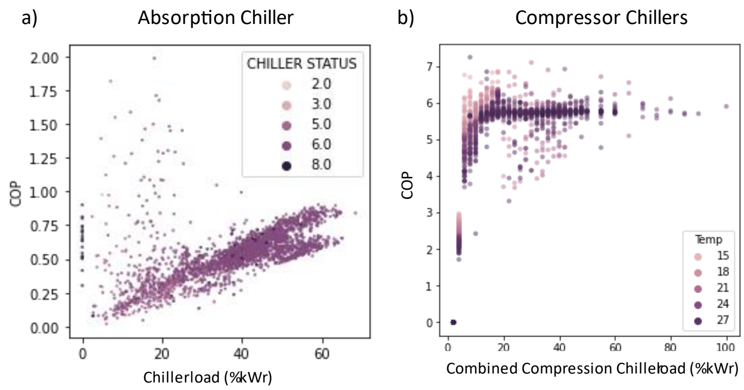

Figure 28: Coefficient of performance (COP) for the pilot study site's a) absorption chiller and b) the combine compression chiller system.

Heat recovery for space heating:

Heat recovery for space heating in co/trigen system typically occurs via heat exchange and has a shorter lag time than cooling via the absorption chiller. Our analysis of the pilot site's data indicated that the time constant from gas input to the generator to heating output in the heating hot water (HHW) system, through a heat-exchanger, was in the order of 15 mins. Based on this lag time, it is estimated that heat recovery will only occur for 1 h 45 mins before there is no longer a need to heat the building to meet heating demand (see Figure 29).

However, our analysis indicated that the benefit is negligible when considering the gas consumption savings from a boiler. Figure 30 shows the daily boiler gas consumption from one of the pilot study's buildings for heating the base building's HHW system for a week in 2021 during winter. The gas generators were not operational on two days, and the base building HHW was heated only using the gas boilers. For the remaining three days, when there was a heating demand in the building, the base building's thermal demand was met by operating both the gas boilers and the trigeneration heat recovery system. The savings in gas consumption from the boilers for the remaining three days were estimated by linearly scaling the thermal load /demand of the building. The analysis estimated that operating the heat recovery for space heat for 1.2 h, 5 h and 9.3 h, yielded a reduction in boiler gas consumption of 0-2%, 5% and 30%, respectively, (+/- 2.5%). Consequently, it is expected that significant gas savings were only realised when heat recovery was operated for longer durations, in the order of several hours.

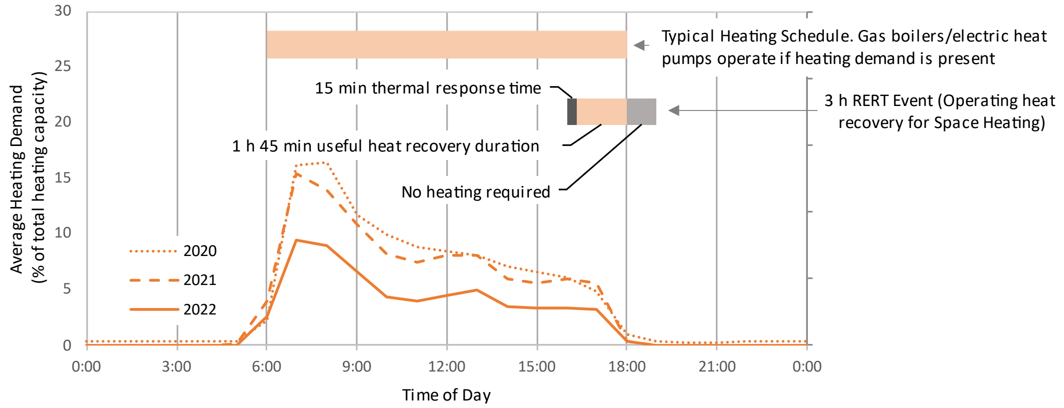

Figure 29: Average heating demand of the pilot study site building during a business day, compared with the typical plant operational hours and the short durations that co/trigen heat recovery could operate generators responded to a 3hr RERT event starting at 4pm.

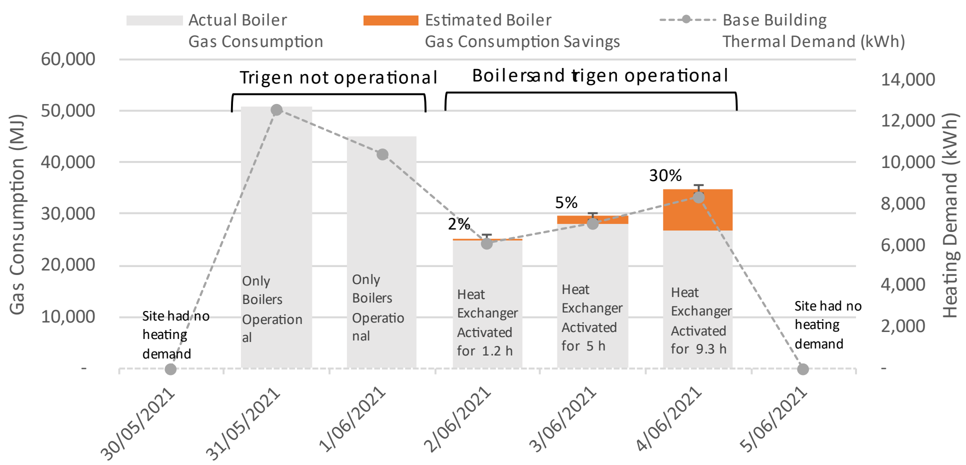

Figure 30: Estimated benefits of operating heat recovery for space heating. Daily gas consumption from boilers for the pilot study site, and the estimated savings in gas consumption when the heat produced by the generators is used for space heating.

Appendix D – Building Owners' Guide

The Building Owners' Guide (below) sets out clear utilisation pathways for building owners with cogeneration/trigeneration (co/trigen) units. It was developed off the findings of this project.

Building Owners' Guide

Building Owners' Guide

Overview

If your building has a co/trigen system installed, there is a good chance that you will have turned it off due to the costs of operation, leaving you with a lot of sunk capital. However, if the generator is still serviceable, there is an opportunity to use this to create a net positive revenue stream via its use in demand response for the building and for the wider electricity market. This guide will help you understand whether and how to adopt this opportunity, by answering the following questions:

- How can co/trigen systems be used for demand response?
- What is the recommended approach to participate in demand response?
- Will it be cost-beneficial?
- Will there be a net environmental benefit/What's the impact on my NABERS Ratings?
- What are the effects of switching from natural gas to biogas

Examples of calculations for financial and environmental impact are provided.

How can co/trigen systems be used as demand response units?

The most viable application of co/trigen systems in demand response is where the systems are no longer in regular use but have not been decommissioned. Systems that are in regular use may already be operating during a demand event and therefore unable to provide the scale of response available from a system that only turns on for the demand event; in that case, operation in demand response for these systems is an opportunity to continue revenue earning operation once the decision to cease regular operation has been made.

Due to the sporadic nature of demand response operation, there is little benefit in the operation of heat recovery or absorption chillers during demand response events; the system is operated purely as a gas engine driven generator.

There are two level of demand response that can be considered:

1. Site electricity demand. The generators from the co/trigen units can be used to minimise peak demand charges arising from building energy use peak demands or from the combination of building demand with sudden fluctuations arising from short-term reductions in on-site PV generation (i.e. when the sun goes behind a cloud).

2. Grid demand events. Grid demand events occur when there is a shortfall in generation relative to the load, either because of excessive demand or because of short-term deficiencies of generation. There are several different types of grid demand events:
    - RERT: The Reliability and Emergency Reserve Trader events are signalled by a forecasted shortfall in energy reserves, typically when there's a combination of hot/ extreme weather, high demand, generation or transmission outages. RERT events are enacted by AEMO, are infrequent, and typically last 3 – 6 hours.
    - Wholesale demand response: These are events that are signalled by a spike in the spot price of electricity. Duration is variable, depending on settings selected by the demand responder.
    - FCAS: Frequency Control Ancillary Services. These are events that are signalled by a loss of control of frequency and are fast response events of short duration. Due to these characteristics, they are less well suited for generator response and so are not considered further.

Revenue Streams

The key revenue streams available from demand response are as follows:

- Site peak demand management: This is the operation of the generator to even out demand spikes that would otherwise set the demand charges on the site's electricity bill.
- RERT: RERT is a market mechanism that AEMO enacts when electricity reserves are depleted. During a RERT event, the generator can be operated to reduce the site's demand. The site receives payment for being on standby when the event is preactivated, and for reducing their demand during the event if the event is activated.[35]
- Wholesale demand response: This is the operation of the generator to reduce demand, relative to baseline determined from historical site demand. Payment is received based on the magnitude of demand reduction and the spot price at that time.

Recommended Approach

The high annual cost of maintaining a generator in working condition for demand response, and the variable nature of returns from demand response, mean that reliably cost-beneficial operation is only possible when all available demand response opportunities are engaged.

For building owners, the use of a third party such as a retailer or a demand response aggregator is strongly recommended rather than direct participation as a market-registered participant. This avoids the complexity of becoming a market-registered participant and creates new opportunities by becoming part of a portfolio of demand response: It enables demand response below 1MW to participate and provides a level of flexibility in response not necessarily available as a stand-alone participant.

The following steps are recommended to get started with investigating whether there is a case in further exploring the use of co/trigen systems in a commercial building:

1. Contact a service provider or electricity retailers that operate virtual power plant or offer demand response programs.
   Examples include EnelX, Shell Energy, EnergyAustralia, and Flow Power. You can contact electricity retailers that are not your retailers.

[35] Electricity consumers are also charged a market fee based on their electricity consumption during a RERT event. The reduced demand during RERT events will also lower the total RERT charges incurred.

Often, service providers can help to provide an estimate of the potential revenue if you choose to participate. They may also be able to help estimate the demand reduction capacity of your site in such events.

2. Determine if it will be cost-effective
3. Determine the environmental impact and impact on your NABERS Rating.

Will it be cost beneficial?

The following items need to be considered when determining whether it is cost-beneficial to operate the co/trigen system as demand response units:

- Primary considerations (these have the most significant impact on the assessment)
  - Gas generator operating and maintenance cost
  - Revenue from participating in the demand response events
- Secondary considerations- these have a minor influence on the analysis and can generally be ignored in a first estimate.
  - Avoided costs such as
    - Avoided RERT event charges
    - Avoided grid electricity consumption costs
  - Cost incurred from gas consumed by the generator
  - Generator efficiency

Will there be a net environmental benefit/What's the impact on my NABERS Ratings?

Operating a generator for demand response will increase gas use. However, the question of whether this increases or decreases emissions depends on whether the generator produces electricity at a higher or lower emissions intensity than the grid.

At grid level, the real-time impacts of gas engine response are most likely to increase emissions. This is because, in most states, electricity network emissions intensity is lower during demand response events than it is on average. However, this short-term issue must be offset against the extent to which the availability of demand response increases the potential of the grid to have a greater capacity of renewable energy generation connected. From this perspective, it is expected that the overall effect is a reduction in emissions.

At site level, emission calculations for reporting and for NABERS ratings are based on annual average emission factors. In 2022, the current state of play is:

- VIC: Gas generator operation is likely to reduce overall site emissions
- QLD, NSW, NT, and WA: Gas generator operation may reduce emissions for generators operating at efficiencies above 23%, 26%, 27%, and 29%, respectively.
- SA and TAS: Gas generator operation will increase emissions

It is noted that the grid emissions intensity figures for each state are all on a downward trend so over time the tendency will be towards gas generators to become more emissions intense than the local grid. In all cases, however, the small number and duration of demand response events means that the actual impact as a proportion of site emissions is likely to be close to undetectable.

What are the effects of switching from natural gas to biogas?

There is currently a trial scheme to sell biogas across the gas network similarly to how Green Power is sold on the electricity network. The financial implication of using this opportunity to switch from natural gas to (reticulated) biogas is currently unknown due to uncertainty in the retail price of biogas. However, the approach described in the early section can be used to determine if it is cost beneficial.

Switching from natural gas to biogas will be make the emissions intensity lower than the average grid emissions intensity across all states and territories because the emission factor for using biogas is approximately 10 times lower than that of natural gas.

Example:

The following is an example of how the cost-effectiveness, environmental and NABERS Rating impacts of using gas generators as demand units can be assessed. The revenue rates mentioned are examples and may not necessarily reflect the actual rates on offer. Rates will vary depending on the service provider and location. More accurate ratings should be obtained from the service provider or electricity retailer.

Example: Cost-effectiveness assessment
Consider a building in Victoria, with a trigeneration electrical capacity of 1 MW. The full capacity (1MW) is contracted to participate in RERT, network and wholesale demand response events. As the cost of operating and maintaining (O&M) the cogeneration and trigeneration system can vary widely, three different annual O&M (excluding the fuel costs) costs are considered in this example; \$40,000, \$60,000 and \$80,000. These are equivalent to \$40, \$60 and \$80 per kWe of capacity per year. ***RERT Event Participation:*** Estimated Revenue from RERT event participation (assuming one 3 hour event in a year): Revenue from RERT events $Revenue\ from\ event\ preactivation$ $= Preactivation\ Rate\ (\$/MW) \times Capacity\ (MW) \times Number\ of\ preactivation\ events$ $= \$10{,}000 \times 1 \times 1\ event = \$10{,}000$ $Revenue\ from\ the\ activated\ event$ $= Activation\ Rate\ (\$/MWh) \times Capacity\ (MW) \times Dispatch\ Duration (h)$ $= \$9000 \times 1\ MW \times 3h = \$27{,}000$ $Total\ Revenue\ from\ the\ event$ $= Revenue\ from\ event\ preactivation + Revenue\ from\ the\ activated\ event$ $= \$37{,}000$ Note: if no RERT events are preactivated during the year, there will be no RERT payments. ***Participation in Wholesale Demand Response Events:***

Here is it assumed that a contract with the third party/ service provider has been established and that there is an annual payment based on the capacity of the system ($50,000 per MW) plus a payment based on the number and duration of events.

In the case where there are no events:

$$\begin{aligned} Revenue\ from\ WDR\ &= Annual\ Capacity\ Rate\ (\$/MWh) \times Capacity\ (MW) \\ &= \$50{,}000 \times 1\ MW = \$50{,}000 \end{aligned}$$

If there are 40 h worth of events in the year, and for all events, the site reduces the grid demand by 1 MW,

$$\begin{aligned} &Revenue\ from\ WDR \\ &\quad = Annual\ Capacity\ Rate\ (\$/MW) \times Capacity\ (MW) \\ &\quad + Dispatch\ Rate\ (\$/MWh) \times Capacity\ (MW) \times Event\ Duration\ (h) \\ &\quad = \$50{,}000 \times 1\ MW + \$200 \times 40\ h = \$60{,}000 \end{aligned}$$

Total Revenue versus O&M Cost:

$$Total\ Revenue\ from\ RERT\ and\ WDR\ Events = \$37{,}000 + \$60{,}000 = \$97{,}000$$

Assuming that the cost of operating and maintaining a 1 MW system is $80,000, the total revenue from the event is higher than the cost of operating and maintaining the system ($97,000 versus $80,000). The financial outcome is more promising for systems with a lower O&M cost; e.g. ($97,000 versus $40,000 and $60,000).

Additional Note:
Calculations for the cost of generator fuel consumption, avoided energy consumption costs, and avoided RERT charges are not shown. However, these components have a minor contribution to the overall analysis. It is estimated that for all assumptions mentioned above, gas consumption will cost approximately $7,000, and the avoided grid electricity consumption will save approximately $5,000.

The secondary costs can be estimated using the following equations:

1. $Estimated\ Avoided\ RERT\ charges$
   $= Capacity\ (MW) \times Dispatch\ Duration(h) \times AEMO\ RERT\ Charge$
2. $Gas\ consumption\ Charge$
   $= ((Capacity\ (MW) \times Dispatch\ Duration(h))/\eta_{el}) \times Gas\ Price\ (\$/kWh)$
3. $Avoided\ Energy\ Consumption$
   $= \big(Capacity\ (MW) \times Dispatch\ Duration(h)\big) \times Electricity\ Consumption\ Charge(\$/kWh)$

Due to the sporadic nature of grid events and using the site's historical demand to determine the magnitude of demand response in an actual event, participation in grid events is unlikely to yield peak demand savings. Peak demand savings may be realised by operating the gas generators to limit the peak demand at a site without on-site renewable generation. However, this mode of operation may have potential negative impacts to the demand response revenue streams discussed in this guide.

Example: Net Environmental Benefit and Impact on NABERS Ratings

Consider a site in Victoria where the generator has an electrical efficiency (η_{el})[36] of 25%.

$$Generator\ Emission\ Factor = 3.6\ \times \frac{Gas\ Emissions\ Factor}{Generator\ Efficiency} = 3.6 \times \frac{0.05553}{25\%} = 0.7996\ \text{Kg}\ \text{CO}_{2-\text{e}}/\text{kWh}$$

This generator emissions factor is less than the grid emission factor for Victoria (1.09 Kg CO_2/kWh). Therefore, there is a net environmental benefit of using the co/trigen systems in this case.

State	Gas Emissions Factor (Natural Gas) (Kg CO_2-e/KJ)	Grid Emissions Factor (Kg CO_2/kWh)
NSW & ACT	0.06463	0.9
VIC	0.05553	1.09
QLD	0.06033	0.93
SA	0.06223	0.52
WA	0.05563	0.7
TAS	0.05153	0.17
NT	0.05153	0.7

Further Reading:

AEMO has information on each of the demand response methods discussed above on its website.

- RERT:
  - "Fact Sheet - The Reliability and Emergency Reserve trader" https://aemo.com.au/-/media/files/learn/fact-sheets/rert-fact-sheet-2020.pdf
- Wholesale Demand Response:
  - "Wholesale demand response mechanism final rule" https://www.aemc.gov.au/sites/default/files/documents/information_sheet_-_for_publication.pdf
  - "Wholesale demand response mechanism – How it works" https://aemo.com.au/en/initiatives/trials-and-initiatives/wholesale-demand-response-mechanism
- FCAS:
  - "Guide to Ancillary Services in the National Electricity Market" https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ancillary_services/guide-to-ancillary-services-in-the-national-electricity-market.pdf
  - "Ancillary services" https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services

[36] The electrical efficiency can be determined either from generator specification documents, or by dividing the amount of electricity generated by the amount of gas consumed by the generator.