Econnect

Demand Management and Planning Project

Preliminary Feasibility Study

Econnect Project No: 1724

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Executive Summary

1.1 Outline

A number of standby diesel generators exist in the Sydney CBD to provide emergency supply in the event of mains supply interruption. The Demand Management and Planning Project (DMPP) is considering the use of part or all of these generation sites to provide dispatchable distributed generation during peak demand periods (peak lopping) and an additional level of supply redundancy in the event of network outages. This strategy may be implemented in conjunction with other demand management strategies.

The DMPP has identified 53 standby generation sites in Sydney CBD (total generation capacity of 85 MVA) which were investigated by Econnect for their feasibility for conversion to peak lopping duty and hence incorporation into the proposed demand management scheme

The Department of Planning (DoP) retained Econnect Australia to assess the technical feasibility and associated costs of such scheme and outline a strategy for its implementation considering all relevant technical issues.

The key objectives of the study were to identify

- The total available dispatchable generation capacity and demand reduction (MVA) based on a preliminary assessment of the technical constraints.
- Estimate the capital costs of implementation for each of the identified connection options: low voltage (LV) connection with parallel operation, LV Connection with Synchronous Close Transfer Trip operation (SCTT), high voltage (HV) connection with parallel operation and LV connection with sequential switching).
- Outline a conceptual technical framework that would enable central dispatch of the generators by the Distribution Network Service Provider (DNSP).
- Identify other strategies for Demand Management to enhance the development of renewable energy and distributed generation projects.

1.2 Conclusions

The following conclusions have been reached:

1.2.1 Technical Constraints and Solutions

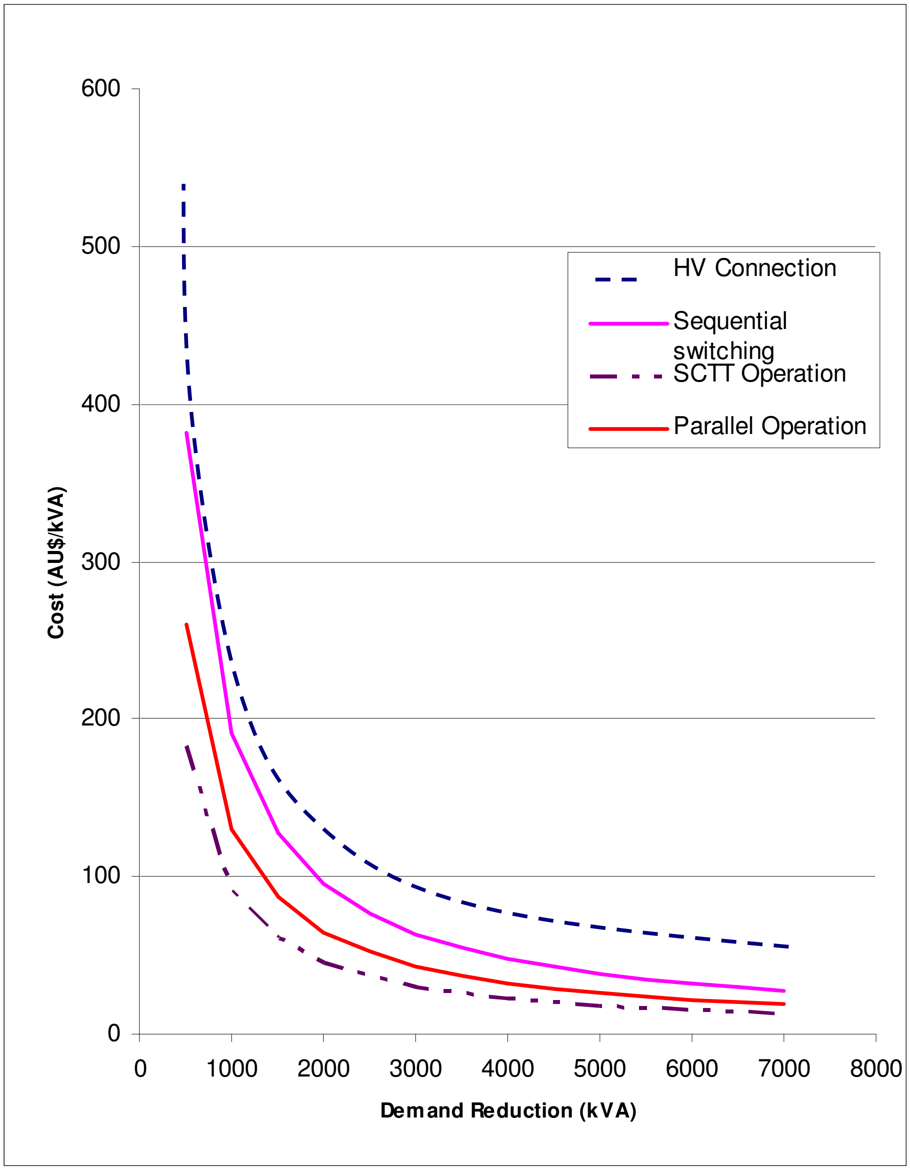
- Fault levels in the Sydney CBD distribution network at low voltage are approaching the design fault ratings of the LV switchgear (within 10% of the design rating). The prospective fault contribution of the generators in most cases increased the fault levels to exceed the design ratings, making parallel operation for a LV connection infeasible in the absence of other techniques. Refer to Table D1 – Appendix D.
- HV connection of the generator is one technically feasible option to resolve the issue with LV fault level constraints. This solution requires additional space for the location of transformers which may be a barrier to implementation at some sites. Refer to Table D1 – Appendix D for fault levels.
- A change to the DNSP operational switching philosophy to implement sequential switching will significantly increase the level of generation available for LV connection at lower cost than for HV connection. Refer to Table D3 – Appendix D.

1.2.2 Generator Connection Options

Based on the above conclusions the following connection options were investigated:

1) **HV Connection (Parallel Operation):** This option proposes connection of the generator(s) to the 11 kV side of the distribution substation, refer to Section 3.3.2.1
2) **LV Connection with Sequential Switching (Parallel Operation):** This option proposes the introduction of sequential switching controls to actively manage the LV fault levels at the distribution substation through the switching of one out of three of the redundant LV supplies to the distribution substation. The purpose of sequential switching is to reduce the LV fault level to permit the generator(s) LV connection. Refer to Figure 7 and Section 3.3.2.2.
3) **LV Connection (Parallel Operation):** This option involves the LV connection of the generator in parallel with the mains supply to permit load reduction or export of power into the distribution network. The implementation of this option is constrained by the distribution network LV fault levels. Refer to Section 3.2.3
4) **LV Connection (SCTT Operation):** With this option, the generator(s) will only be connected to the network for a short time during load transfer and then disconnected to operate in island mode. This option may be constrained by power quality issues. Refer to Section 3.2.2.

The anticipated size of demand reduction (MVA) obtained from feasible sites for each option and the connection cost rate ($/kVA) are presented in the following Figure:



Connection cost (AU$/kVA) versus demand reduction (kVA) per site by connection option.

The SCTT option looks more attractive than the other options in terms of both cost of connection and the size of demand reduction. However, it may be technically infeasible due to a reduction in power quality when in island mode. The cost of this option will escalate above the reported figure when the rating of the generator is less than the customer's peak demand and no segregation exists between essential and non-essential loads. In addition, the level of demand reduction will be dependent on the customers load at the time of dispatch and will be less than the generator rating. Grid export is not possible with this option.

Connection Option	No. of Feasible Sites	Total Demand Reduction (MVA)	Total Connection Cost (AU$)
HV Connection	30	71	8.6 m
LV Connection (Sequential Switching)	24	35	6.8 m
LV SCTT Operation	16	37	2.3 m
LV Connection (Parallel Operation)	7	5	917,000

Table 1 Illustrates Number of Feasible Sites, Total Demand Reduction, Total Connection Cost for Each Connection Option.

1.2.3 Centralised Dispatch Control Strategy

A strategy for central dispatch of the generators by DNSP was proposed (refer to Appendix C). This strategy will allow the generators to provide services to the DNSP such as relief in potential network overloads and also could provide ancillary services and reserve by aggregating a number of existing generators together under one control scheme. The total cost for implementation of such a strategy on the DNSP central control room, five each Sydney CBD zone substations and 53 each generation sites (excluding communication infrastructure between sites and zone substations) is AU$ 2.9m. The minimum cost for a working system including the central control room, one zone substation and a single customer components is $240k. The cost per additional customer site is AU$ 48,000.

Low cost and reliable communications technology will be required to transmit the control signals to the distributed load controllers. Existing PSTN (Public Switched Telephone Network), mobile network, fibre optics, and UHF radio should be considered as low cost and reliable options.

1.2.4 Health, Safety and Environment

Diesel-driven generators are high NOx emitters. Typical NOx emissions from uncontrolled diesel generators range from 10 to 14 grams per horsepower hour (equivalent to 13.5 to 19 kg/MWh), depending on the engine rating. Appropriate management of NOx emissions will be required..

1.3 Recommendations

A combination of the HV Connection option and LV Connection with Sequential Switching options should be applied to achieve the largest total demand reduction (80 MVA). LV connection with SCTT operation may be a more cost effective option for customers where supply power quality requirements may be met with the generator islanded.

Appropriate management of CO_2 and NOx emissions is recommended if widespread use of diesel generators for peak generation is proposed. This may be achieved by installation of air pollution control equipment such as selective catalyst reduction devices (SCR). The cost for a SCR system for diesel generators ranges from AU$ 150,000 to AU$ 200,000, depending on the size of the engine.

We recommend the following issues are the subject of a more detailed feasibility study:

1. Demand Reduction – It is recommended that load and generator connected to the main switchboard at the proposed sites to be checked to confirm the level of available demand reduction;

2. Risk Management – a formal risk assessment is recommended to evaluate the risk of supply interruption to critical loads. For parallel operation, this will include power systems analysis and transient stability studies.
3. Load Management and Generator Dispatch System – Remote DNSP automatic controls and monitoring are required to be located in the DNSP Control Room and DNSP Zone Substation for control and monitoring of distributed generation and will ideally be integrated with the existing SCADA system;
4. Sequential Switching – Design of sequential switching scheme and interface with existing protection and controls;
5. Communications - The method of communications to accommodate the proposed central dispatch of the generators.
6. Power Quality – Investigation of power quality issues to confirm the feasibility of island operation (SCTT operation) on a per site by site basis;
7. Maintenance – Estimation of additional ongoing operation and maintenance costs;
8. Reliability – Run tests to confirm generator will function reliably for required duty and expected load variations.

2 Introduction

There are a number of standby diesel generators connected in the Sydney CBD that provide back up supply to grid connected customers in the event of a system outage. As part of a demand management program, the Department of Planning is proposing to use some or all of these generators to provide additional generation capacity within the Sydney CBD during Peak demand periods.

The Department of Planning has identified some 85MVA of standby generation capacity located at 53 sites in the Sydney CBD which may be eligible for this scheme. Table D2 – Appendix D shows the proposed generation sites with the rated generation capacity for each. The generation capacity per site varies between 0.5 MVA – 7 MVA.

The Department of Planning has approached Econnect Australia to assess the technical feasibility and associated costs of such a scheme and to outline a strategy for its implementation taking into consideration a variety of technical and economic factors.

2.1 Objectives

The objective of this proposal is to establish or otherwise the feasibility of the scheme detailed above and to identify major technical impediments, constraints and costs associated with the conversion of the standby generator sets for either of Parallel or Synchronise – Close – Transfer - Trip (SCTT) operating modes.

The study will also outline a conceptual technical framework that will enable the central dispatch of the generators by the network service provider concerned.

In undertaking the study, the Department of Planning wishes to take advantage of the comprehensive knowledge, specialist skills and extensive experience of Econnect in relation to the development of renewable energy and distributed generation projects, electrical infrastructure and grid connection and compliance issues.

2.2 Scope of Study

Part A: Technical Overview

This section will address in high level terms the technical issues/constraints related to the conversion of standby generation for Parallel/SCTT operations. Issues related to both the redesign of the generator connection and to the grid integration of the generator will be addressed as follows:

I. Generator Issues

- i. Standby Operation
- ii. Synchronise Close Transfer Trip Operation
- iii. Parallel Operation
- iv. Design Dissimilarity Overview
- v. Typical conversion costs

II. Network Issues

- i. Thermal Consideration

ii. Fault Level Consideration

iii. Voltage Regulation Consideration

iv. Protection/Control and Communication

v. Power Quality Consideration

Part B: Case Study

This section will use the results obtained from Part A analysis as a framework to focus the study on the significant issues associated with this project.

This section proposes a review of available generator/network data in order to identify a shortlist of generation sites which will constitute a representative sample of the Sydney CBD generation site portfolio. Our target would be to limit the case study to five cases.

Results from this section of our analysis will be used to form a view of the constraints/challenges related to the proposed change of operation of the standby generation as well as any significant associated costs.

Part C: Appendix C - Demand Management Integrated Strategy

This section will outline a strategy for the deployment of the scheme based on Econnect's international experience with similar demand management programs. It will address the following principle areas:

i. Scheduling and Dispatch of Generators: technical and commercial considerations

ii. Provision of a comprehensive list of regulatory tools and levers which may be utilised to enhance the market for the application of the proposed scheme in addition to other sustainable energy solutions.

iii. Inclusion of a qualitative assessment and review of each of the measures identified in ii) above. This will include an analysis of the speed with which each measure may be implemented as well as associated costs.

iv. Demand management the way forward:

The use of standby generation capacity represents only one of the potential measures that may be employed to improve the balance between electricity supply and demand leading to long term efficiency gains, optimal network management, cost savings and reduced greenhouse gas emissions. There are a variety of other areas that are worth exploring and which may be the scope of further study. These will be highlighted in this report and will include such things as Controllable Generation (Standby generation but also the use of Micro CHP, etc), Load Management, New Energy Storage techniques and other areas.

2.3 Distributed Generation Benefits

The distributed generation benefits can be summarised into the following:

- **Technical and Economic Benefits:**
  i. **Distribution and Transmission Losses:** High penetration of distributed generation, especially at peak periods would reduce power flow from the HV network to the load, reducing power losses across the distribution and transmission.
  ii. **Ancillary Services & Supply Security:** Distributed generators provide ancillary services to the distribution network operators (DNSP) such as local voltage support, and network security as well as services for the overall system operator such as frequency response and reserve by aggregating a number of distributed generators together under one contract and control scheme.
  iii. **Deferral of Network Investment:** By installing Distributed Generation close to the end user, avoidance of investment in the HV network would increase. Further, the contribution of the DG in supply security and voltage/frequency stability improvement would defer the investment in additional ancillary services.
- **Climate Change Benefits:** Avoidance of line losses by having low emission DG close to the load (Distribution level) could result in a displacement of 0.7mt CO_2e (CO_2 equivalent) per TWh of coal / gas. Appropriate management of CO2 and NOx emissions is recommended if widespread use of diesel generators for peak generation is proposed, see Section 3.2.4.

2.4 Demand Management Benefits

There are many potential beneficiaries of efficient demand management:

- Retailers can gain through lower exposure to peak price risks for wholesale energy;
- Networks through improved asset utilisation and deferral of network capital expenditures;
- End-users through lower energy bills and better energy services; and
- The community through better utilisation of resources and fewer environmental costs

3 Part A: Technical Overview

3.1 Overview of Existing Distribution Network

3.1.1 11 kV Energy Australia Distribution Network for Sydney CBD

The 11 kV distribution network of Sydney CBD is supplied by five zone substations as shown in **Figure 1**. City North and City East 33/11 kV substations are supplied at 33 kV from Energy Australia Pyrmont and Surry Hill 132/33 kV substation respectively. 132/11 kV Dally St is supplied at 132 kV from Transgrid Sydney North substation. 132/11 kV City Central and City South are supplied at 132 kV from Haymarket substation[1].The load in the CBD is commercial, though there is an increasing number of residential buildings. Summer peak demand in the CBD is very flat between 10:00 AM and 6:00 PM on weekdays. Peak demand ranges between 570 – 580 MVA, refer to **Figure 2**.

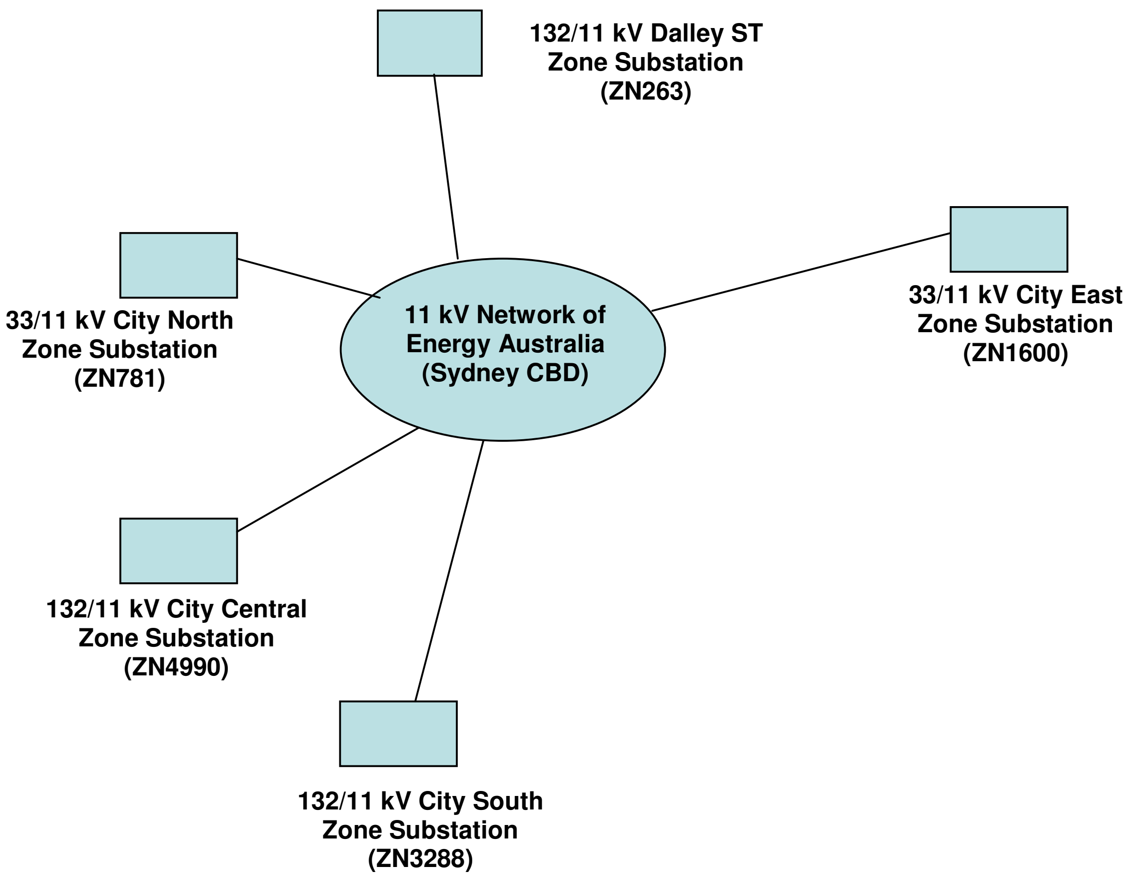


Figure 1: 11 kV Energy Australia Sydney CBD Distribution System

[1] Energy Australia,'Demand Management Screening Test – Sydney CBD', 6 December 2005.

3.1.2 CBD Network and Supply Issues

The distribution network issues for Sydney CBD can be summarised in to the following:

- The need for progressive upgrade of the older parts in the distribution system. A new substation is under construction to replace the oldest substation in Sydney CBD (City North Zone substation) by 2010. There is a need to replace second oldest substation in Sydney CBD (City East Zone substation) by 2013. Also some old items of equipment require replacement at Dally substation.
- Changes to the regulatory requirements for security standards for Sydney CBD supply. The new changes to the security standards require the CBD supply (Zone substations and sub transmission feeders) to be designed and operated so that it can carry the full forecast load when n-2 contingency occurs (two elements of the supply are out of service). The system should comply with new standards by 1 of July 2012. **Figure 2** shows the large reduction in CBD supply capacity in 2012/13 due to the change in the regulatory requirement.
- Continuous growth in peak demand. Peak summer demand is forecast to rise continuously as shown in **Figure 2**. This will require the current capacity of the supply to be expanded by 2012 in the absence of demand management initiatives.

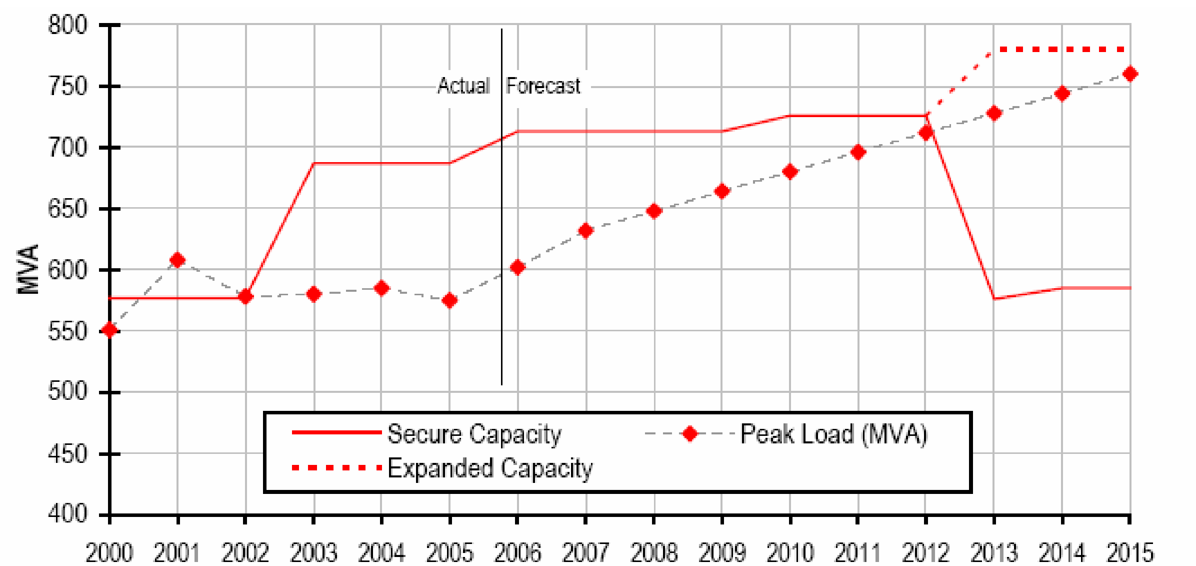


Figure 2: Chart of Actual/Expected Demand V Effective Supply Capacity[1]

3.1.3 Demand Management Options

To meet the new change in supply security standards in 2012, the supply capacity will decrease to 575 MVA which is below the peak load forecast in 2012 by 152 MVA as shown in Figure 2.

This will require a demand reduction of 152 MVA by 2012 in order to defer or avoid any investment proposed. In general the average network augmentation cost as indicated by IPART report[2] is 200

[2] Independent Pricing and Regulatory Tribunal of NSW, SKM, M-Co ‘ Reducing Regulatory Barriers to Demand Management, Avoided Distribution Cost and Congestion Pricing for Distribution Network in NSW’, Nov 2003.

AU$/kVA/year. The avoided network augmentation cost per year will be AU$ 30 m/year for 152 MVA demand reduction.

3.1.4 Typical LV Arrangement

3.1.4.1 Network Assets

The customer is supplied at 0.4 kV via an 11/0.4 kV substation. Typically, three parallel 11kV feeders from the zone substation feed a single LV bus/main switchboard via separate 11/0.4 kV transformers. The transformers connect to radial 11kV feeders via isolating and earthing switches, and to the LV bus/switchboard normally via air type circuit breakers. **Figure 3,** shows a typical arrangement for Energy Australia distribution substation.

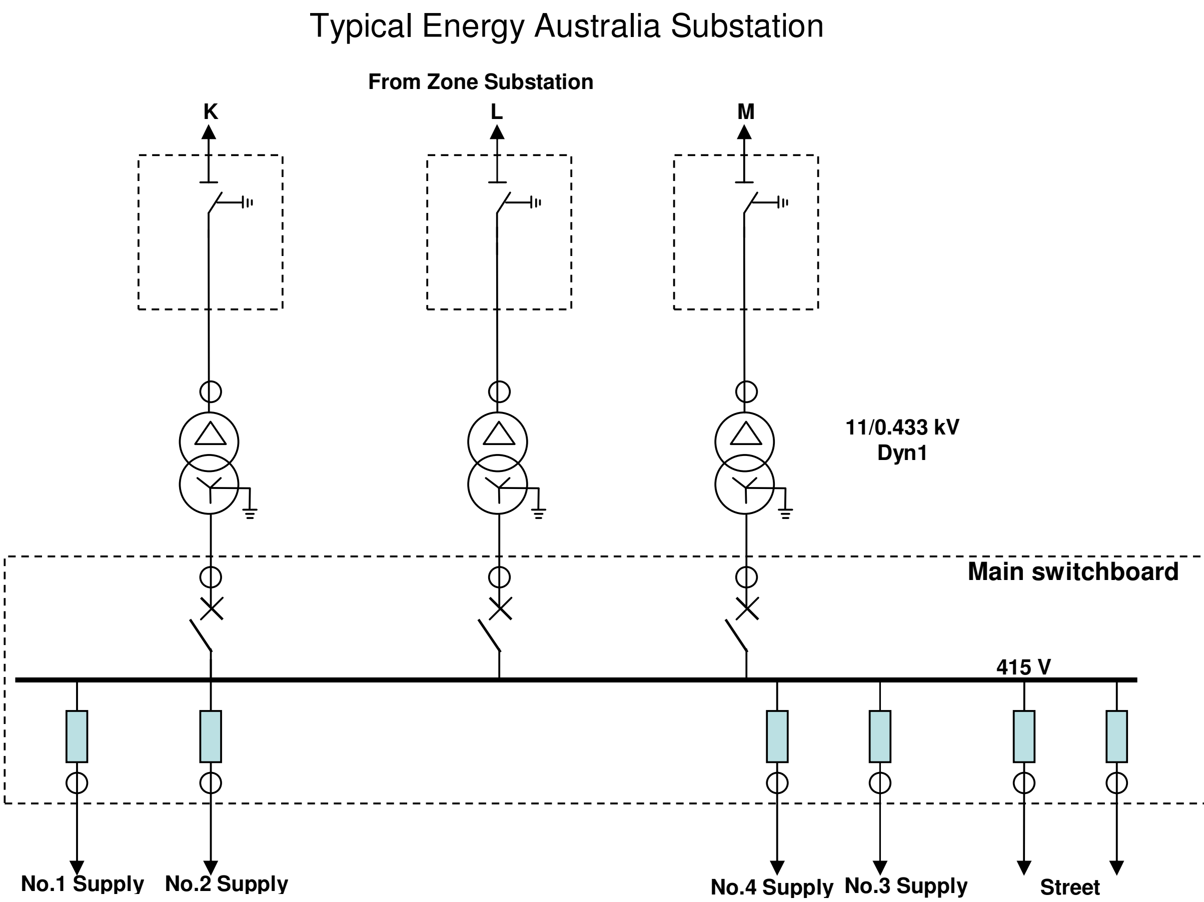


Figure 3: Single Line Diagram of Energy Australia Distribution Substation and LV Arrangement

3.1.4.2 Customer Assets

LV loads are typically supplied from main switchboard via distribution switch boards via cables and LV fuses/fuse switches. Two general LV arrangements are used as shown in **Figure 4**.

Under emergency operation, System A would require opening the main supply C.B and shedding some of non-essential load in order to have total load (essential and non essential) less or equal to the standby generation capacity. While System B enables separation of essential and non essential load through a bus tie or feeder circuit breaker when losing the main supply. This enables essential load to be supplied by the standby generator even in the event of a LV bus fault or circuit breaker failure. This would not require shedding the non-essential load or tripping off the main supply C.B No.1, as the essential load should be equal or less than the standby generation capacity.

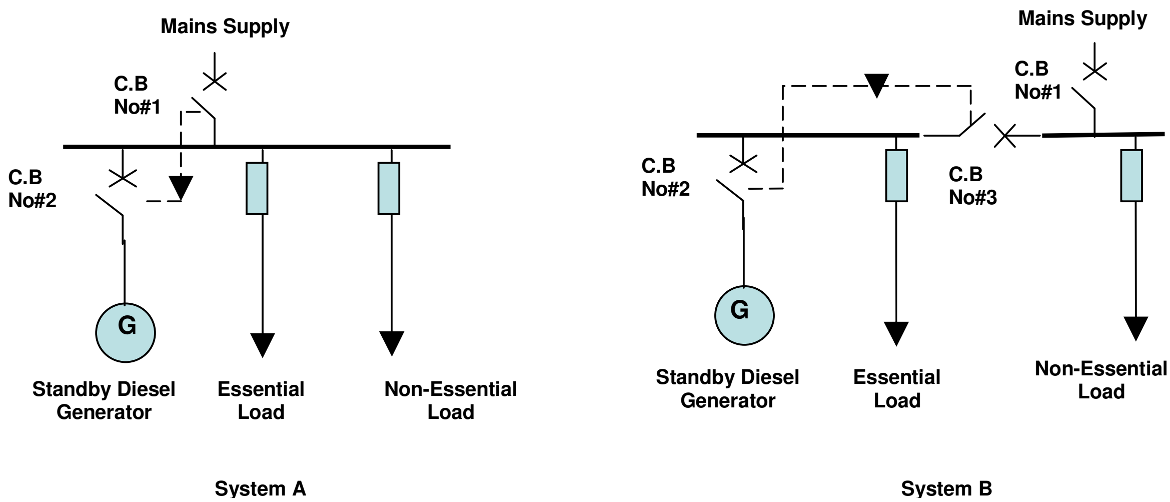


Figure 4: Single Line Diagram Illustrating Standby Mode for Diesel Generator

3.2 Generator Issues

3.2.1 Standby Operation

Standby diesel generator sets provide emergency supply to essential loads in the event of mains supply failure. Essential loads may include fire services, lifts, critical electronic equipment, instrumentation, and emergency lighting.

An auto-transfer switch and automatic generator controls are generally provided to automatically start the standby generator set, disconnect the mains supply and connect the site electrical load to the standby generator set.

With reference to **Figure 4**, normally the total site electrical load is supplied from the mains supply. Upon detection of loss of mains supply;

- Mains circuit breaker (C.B No #1) is tripped;
- Non-essential load is shed if required,
- The generator set is started and brought up to speed;
- Load is transferred to the standby generator set by closing the generator circuit-breaker (C.B No #2).

Figure 4 System B shows an electrical system where essential and non-essential loads are segregated into separate busbars or switchboards. Standby operation for System B is identical with the exception that the bus-tie circuit breaker CB No #3 is tripped instead of mains circuit breaker CB No #1.

During this process, power supply to the site is interrupted for up to ten minutes, the time it takes to start-up and connects the standby generator. Unless mains synchronising capability is provided, it is necessary to interrupt the essential load a second time in order to switch the load back to mains supply when power to the site has been restored. This is one disadvantage of the auto-transfer switch standby configuration. For reliable starting of the generator in an emergency, six-monthly maintenance and exercising of the generator set is required. This requires connection of a load bank unless momentary interruption of supply to essential loads is permitted.

3.2.2 Synchronise-Close-Transfer-Trip Operation (SCTT)

When configured for SCTT operating mode, a generator set is capable of dispatchable demand reduction without interruption of the power supply to the site. The generator will operate in parallel with the mains supply for a short time only (several seconds) during load transfer.

With reference to **Figure 4** System A, a typical generator operating sequence is as follows:

- Initiate start of generator set (manual or automatic);
- Start generator set;
- Synchronise generator to mains supply;
- Close generator circuit breaker (CB No#2);
- Transfer load from mains to generator; and
- Trip mains circuit breaker (CB No#1) to island generator.

To shutdown the generator set, a typical operating sequence is:

- Initiate shutdown of generator set (manual or automatic);
- Synchronise generator to mains supply;
- Close mains circuit breaker (CB No#1);
- Transfer load from generator back to mains;
- Trip generator circuit breaker (CB No#2) to island generator; and
- Initiate generator cool down sequence; and
- Shutdown diesel engine.

SCTT operation for **Figure 4** System B is identical with the exception that the bus-tie circuit breaker CB No#3 is opened instead of mains circuit breaker CB No#1. For demand reduction (peak lopping) this is only feasible when the generator rating exceeds the maximum demand on the connected busbar. In the cases where the generator rating is less than the maximum demand, rearrangement of customer electrical system will be required at additional cost. In many cases this will be infeasible or costly due to physical constraints at the customer premises (i.e. lack of space for installation of additional switchgear).

3.2.3 Parallel Operation

Parallel operation involves the start up synchronisation and connection of the generator to the mains supply for the time period required for network demand reduction. Depending on the rating of the generator set and the local site load, export of power into the electricity distribution network may be possible. Regardless of whether grid export is possible, additional protection may be required to prevent unsafe conditions in the electricity distribution network which may affect nearby customer and distribution network assets and personnel.

With reference to **Figure 4** System A or System B:-

A typical start sequence for parallel operation is as follows:

- Initiate dispatch of generator set (manual or automatic);
- Start generator set;
- Synchronise generator to mains supply;
- Close generator circuit breaker (CB No#2);
- Ramp up generator load to rated output; and
- Continue to operate generator in parallel with mains.

A typical shutdown sequence for parallel operation is as follows:

- Initiate shutdown of generator set (manual or automatic);
- Ramp down the generator load to zero;
- Open generator circuit breaker (CB No#2);
- Initiate generator cool-down sequence; and
- Shutdown generator engine.

3.2.4 Environmental Impact and Economic Issues

Diesel-driven distributed generators are generally used as standby generators with the aim to ensure continuity of supply to essential loads in facilities with an extremely low tolerance for interruption of supply such as lifts, fire services, medical and electronic equipment. The main driver behind this choice of technology was that diesel generators are the only generators that can provide immediate start-up. Furthermore, diesel-driven distributed generators used fuel stored on-site which reduces the risk of a potential interruption of fuel supply that may exist with other type of technology such as natural gas fuelled generators.

However, diesel-driven generators are high NOx emitters with and have an energy efficiency of approximately 35%. Both of these disadvantages were not of much concern for standby generation as this was combined with a very low utilization, typically less than 16 hours per year. Using these generators for peak generation/demand management purposes requires different operational usage with up to 100-200 hours per year. Therefore the original assumptions and environmental conclusions no longer prevail and need to be reassessed.

Figure 5 shows a comparison between the CO2 emissions for various fuels generation.

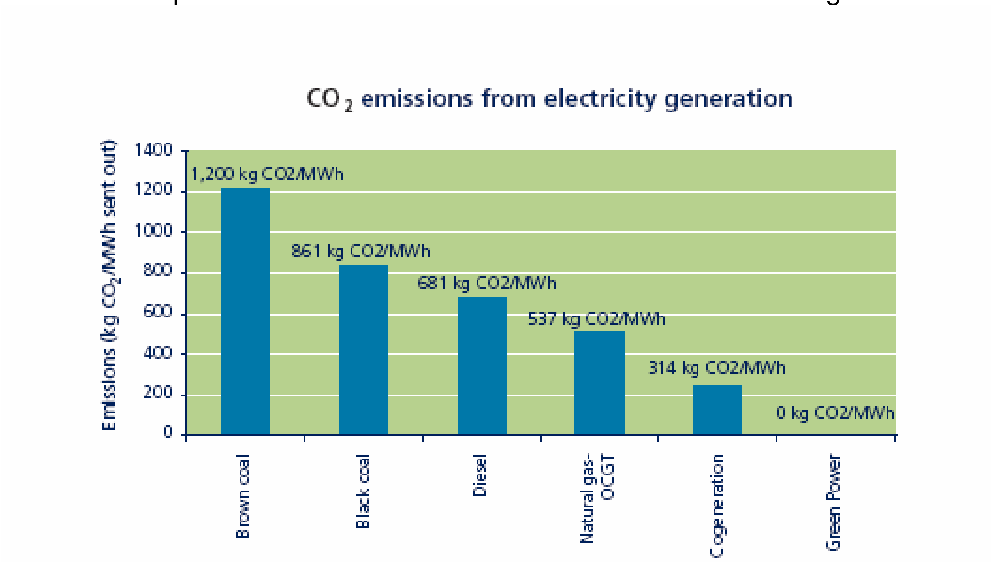


Figure 5: Comparison CO_2 Emission for Various Fuels Electric Generation[3]

When compared with other sources of energy, diesel-driven generators are high NOx emitters (4 times greater than the average emission of all type of generation combined) with typical NOx emissions from 10 to 14 grams per horsepower hour (equivalent to 13.5 to 19 kg/MWh[4]), depending on the engine rating. Typically, diesel engines are average CO_2 emitters and a very low SO_2 emitters (15 times less than the average emission of all type of generation combined).
Therefore appropriate management of CO_2 and NOx emissions will be required. Around 80% emission reductions can be achieved by installation of air pollution control equipment such as Selective Catalyst Reduction device also known as SCR.

[3] Green Power, 'Green Power Business Guide', 2005.
[4] Environ International Corporation,' Estimate of Emission for Small Scale Diesel Engines',2004

Selective catalytic reduction systems work by chemically reducing NOx (NO and NO_2) to nitrogen (N_2). In a lean gas stream, it is necessary to add a reductant to the system to enable this reaction. There are two main classes of SCR system, defined by the source of the reductant used. These are ammonia-SCR (of which urea-SCR is the most common) and hydrocarbon-SCR (lean NOx reduction). Ammonia-SCR systems react ammonia (NH_3) with the NOx to form nitrogen (N_2) and water (H_2O). Typical applications are stationary source and diesel exhaust treatment of truck and bus Hydrocarbon-SCR (lean NOx reduction) systems use hydrocarbons as the reductant. These systems cannot offer the performance of ammonia-SCR systems[5].

The cost for a SCR system for diesel generators ranges from AUS$150,000 to AUS$200,000 for 1 MW – 2 MW engines depending on engine exhaust and engine location. The estimated cost excludes Urea storage tanks, pumps and supply line, thermal lagging, installation, and electrical wiring[6]

Peak operation of diesel generation can be economically justified in some cases, though it should be noted that diesel generators are usually not the preferred options for peak lopping. This can be explained when considering the cost/efficiency profile and environmental impact of such a scheme. The diesel engines consume around 0.3 litre/hour times its kW rating when operated around full capacity[7]. For peak load lopping operation the generator will operate for longer hours than standby/emergency operation which leads to higher fuel consumptions.

3.2.5 Generator Operation and Maintenance Issues

The diesel generator typically consume around 0.3 litre/hour times its kW rating when operated around full capacity. The existing day tank is adequate to operate the generator only for few hours. The day tank is refilled from the main storage tank every time the generator is operated for emergency supply. (Typically the main storage tank capacity is 10 times the capacity of the day tank)

For more frequent operation of the generator (for peak lopping), regular refill for the day tank would be required. However, the frequent refilling could wear out the fuel transfer pumps, the fuel level switches and other fittings. Also, the generator would operate for longer periods at a time. This could result in a risk of turning off the generator due to fuel level detection switch.

Replacement of the existing day tank with larger capacity tank seems an attractive solution. However for some generation sites, physical space is a definite obstacle to implementation. In such cases, it is recommended to maintain the existing day tank and consider more frequent refill. This would require more frequent inspection and maintenance of the fuel transfer and level detection equipments.

In Sydney CBD the peak demands occur on summer days due to increased air-conditioning load. The load profile for Sydney CBD is flat between the hours of 10:00am and 6:00pm on weekdays. **Figure 6** demonstrates the profile of the combined load on the city zone substations on peak days in summer 2004/05.

Assuming that this load profile is the case for 3 months summer season and 5 days a week, the total annual hours when the load is at peak values would be around 500 hours/year. The diesel generator would be allowed to reduce the peak load for only up to 200 hours/ year as required by

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[5] Johnson Matthey Environmental Catalysts and Technologies (ECT)

[6] ECI P/L, Ray Jaworski , 'Quotation 1724 SGIP Recommendation & Budget Prices for SCR Device', Nov 2006

[7] National Procurement Agency, Sri lanka, Typical Technical Specifications for Diesel Generators 500 – 2000 kVA

the Protection of the Environment Operations Act 1997 and Energy Australia requirements for emergency supply operation (at contingency events).

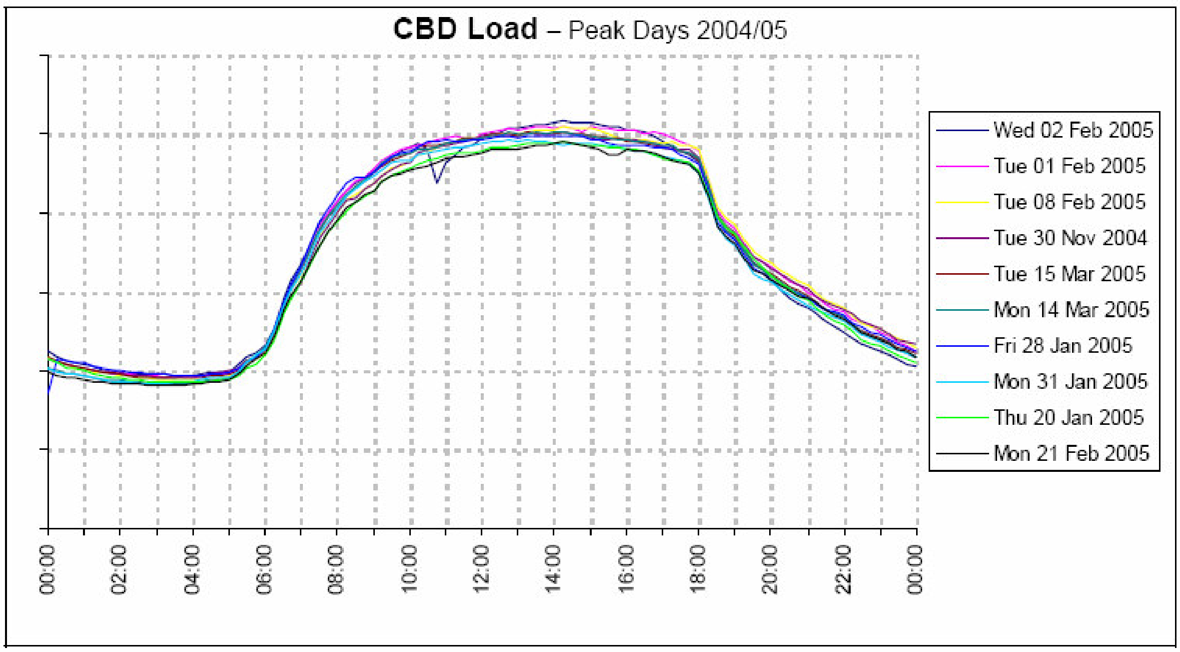

Figure 6: The Profile of the Combined Load on the City Zone Substations on Peak Days in Summer 2004/05[1].

A majority of diesel generators are rated for standby or emergency use. This designation is for generators that will be used typically for short periods of time when the main supply fails. The prime duty rating is applicable when the number of hours per year will exceed the standard hours for standby operation and the use is on a regular basis. Prime continuous duty is the rating given for generators that are used 24-hour per day and 7-days per week.

The prime and continuous ratings are based on the fact that the generator system will perform at the highest standby rating. When the hours or use exceed the recommended standard for standby the life expectancy can be shortened considerably and the risk for premature failure is increased. Running the standby generator at its highest ratings and for longer hours will result in higher temperature and reduce the life of the engine. Regular scheduled service is the key to extend the life of the engine and to maintain the performance.

Diesel engine is due for maintenance every 200 – 250 hours if the engine is located in clean environment (no dust). It would be expected to have scheduled maintenance one time a year.

Normally, the alternator will not require any service unless it is located in a dusty environment. In dusty environments, a high pressure air hosing and occasional blow out of the dust from the generator system will be required.

3.3 Network Issues

3.3.1 Thermal Considerations

Each device in the existing distribution system including transformers, circuit breakers, fuses, lines, cable, etc, have thermal limits. Loading the device above its thermal limit may cause permanent damage or reduction in operating life. Connection of a generator in parallel to a distribution system will change the loading in the system. Therefore, it is important to investigate this issue when considering connection of generator to distribution network. However, connecting a generator at LV level will generally have a beneficial effect when there is a net load reduction of main feeder load. In some cases, the export that results from maximum generation and minimum local load may exceed the thermal limits of the distribution system depending on the rating of the generator.

3.3.2 Fault Level Consideration

Generator connection to a distribution network increases the fault levels throughout the distribution network, most significantly at point of connection (LV level). This increase in fault level is referred to as generator fault contribution.

If the pr-connection network fault level is close to the design fault level of the distribution network, connection of a generator could increase the fault levels beyond the safe design limits presenting a barrier to the connection of the generator.

Fault levels in Sydney CBD distribution network are generally close to the design fault levels on the LV system (refer to Table D1 – Appendix D for 0.4 & 11 kV fault levels). Out of 53 sites only seven sites were feasible for LV connection. Five sites were selected to be case studies for network issues investigations and generator connection and conversion cost estimation.

The fault level issue may be resolved in a number of ways to permit generator connection to the distribution network:

- Current limiter fuses
- High impedance transformer or series reactor
- Network configuration alteration
- Other generator connection solution (HV Connection)

3.3.2.1 Generator HV Connection

This option propose connection of the existing generator to DNSP 11 kV feeder(s) through a new generator unit transformer (11/0.4 kV). The proposed generation sites were investigated for this connection option and a connection design options were proposed to suit each site generation capacity (refer to Figure D1,D2,D3 & D4 –Appendix D) . It was found there will not be any anticipated issues.

Table D1 – Appendix D shows that there is enough headroom for the 11 kV switchgear to accommodate the generator(s) fault level contribution. Therefore, it is confirmed that there will not be an issue in terms of fault level constraints. All new LV equipment including LV switchboard and generator breaker would be selected to accommodate the generator and the network fault levels. The impact of generator fault contribution on the LV fault levels is insignificant as the generator and the LV system are separated by the new connection transformer(s) and the distribution substation transformers.

Based on number and ratings of generators available in each site and the way the generators are connected to the distribution substation, few design cases were identified. Figure D1, D2, D3 and D4 in Appendix D shows the typical design options for connecting the generator to HV side of Energy Australia substation. Table D2 – Appendix D illustrates the total budget cost for HV connection option for each site.

3.3.2.2 Sequential Switching (SS)

This option proposes disconnection of one of the three LV supplies of the distribution substation by opening a single LV circuit breaker (e.g. C.B #3) during the generator operation. The purpose of this option is to reduce the fault level on the LV system by 2/3 of the present fault level to allow the LV parallel connection of the on-site generator. Following the LV circuit breaker switching (C.B#3), the generator will be connected to the LV switchboard. Refer to **Figure 7** which illustrates the new configuration proposed by this option.

In the event of a fault in one of the two operational transformers (TX1 or TX2) or HV fuses, the connection of the other transformer (TX3) is restored by closing the C.B#3. This option would involve minor modification to the distribution substation wiring including the LV circuit breaker controls.

Control of the LV circuit breaker could be achieved by the generator controller. Interlocks between the generator circuit breaker and the distribution substation circuit breakers will be required for safety. Auxiliary contacts to indicate circuit breaker status will be wired to the controller.

Due to disconnection of one of three feeders to the distribution substation, a slight voltage dip is expected, however it is unlikely to be an issue.

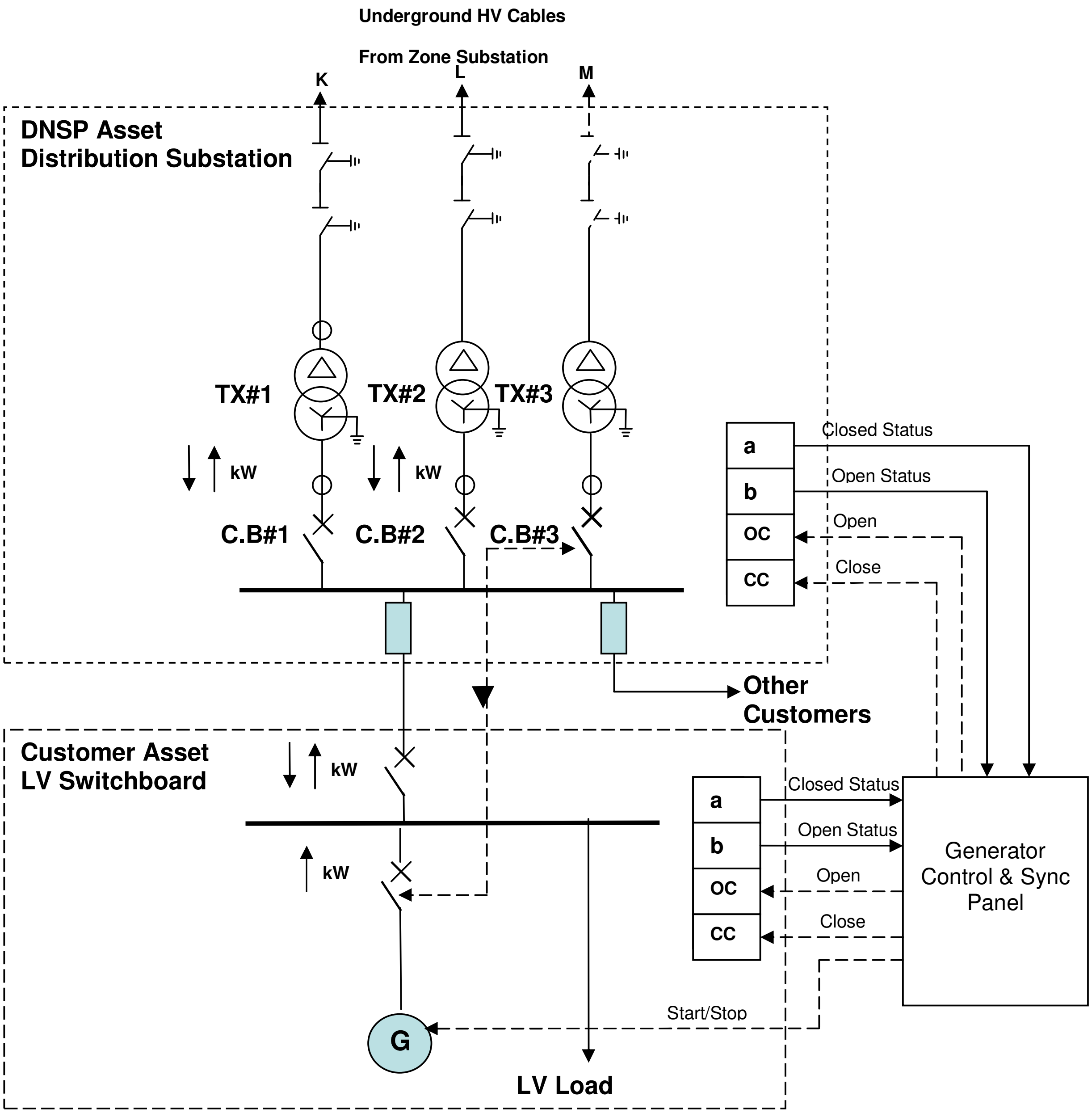

Figure 7: Single Line Diagram Illustrating the Sequential Switching Arrangement

It was found that the fault level at LV side decreased significantly. However, for 11 sites the headroom between the existing fault levels and the design ratings of the LV equipment was not adequate to accommodate the generator(s) fault contribution.

The estimated cost for design modification to the EA substation is AUS$ 60,000 (including AUS$ 40,000 for additional control modification and AUS$ 20,000 for cable and termination). Refer to Table D3 – Appendix D for the budget cost estimates for each site.

The total demand reduction achieved with this option is 35 MVA. The total cost involved for achieving this option is estimated as AUS$ 6.8 m.

3.3.3 Voltage Regulation Consideration

The operation of a distributed generator will tend to increase local voltage levels on the distribution network to which it is connected depending on power factor of operation. Small generation export is expected not to cause feeder voltage to exceed the NSP voltage tolerances.

With peak load lopping operation for the existing standby generators, generation export is unlikely to happen when the generation output is equivalent or less than the local load.

Voltage rise may occur when there is sudden reduction in network load due to operation of the generators and a voltage step reduction may occur when considering sudden disconnection of the generators. These issues will be investigated further in Part B for each study case. Power system analysis will be required on a case by case basis.

3.3.4 Protection/SCADA and Communication

The distribution networks are designed to conduct current from high to low voltages and electrical protection scheme are designed to reflect this concept. The following protection issues may occur when considering parallel operation of the standby generation:

- Generator protection to accommodate parallel operation. That will include:
    - phase instantaneous and time-delayed over current;
    - instantaneous and time-delayed earth fault
    - reverse power
    - other standard generator protections
    - back-up over current protection relay including:
        - phase instantaneous and time-delayed over current;
        - instantaneous and time-delayed earth fault
    - anti-islanding (G59) relay including:
        - rate of change of frequency (ROCOF df/dt) or vector displacement
        - under / over voltage
        - under / over frequency.
    - primary and backup auxiliary tripping relays.
    - D.C. battery-backed power supply.

All of the above equipment may be installed in a single Generator Control and Protection panel. It is recommended that protections are wired as shown in Appendix A – Figure A1.

Islanding or loss-of-mains is an issue that can occur in distribution systems. When the main supply is lost and the generator connection is maintained to the distribution network, the frequency and voltage will be affected when the generation and the load are not matched. The islanding could be a potential issue for power quality o other customers. In systems such as the typical Sydney CBD distribution system, the mains supply is coming from three individual 11 kV feeders where losing three of them at the same time is uncommon, hence it is unlikely to have an issue with islanding.

3.3.5 Power Quality Consideration

3.3.5.1 LV Connection (Parallel Operation)

It is anticipated that the contribution of the diesel generator to harmonic voltage distortion levels would be insignificant, since three-phase synchronous generators are not a significant source of harmonics. The connection to the network is unlikely to cause harmonic and voltage flicker issues. Further study is not considered necessary, unless the background levels of harmonics or flicker are already problematic. Therefore, no significant changes in power quality are expected when considering parallel option.

Diesel generators have controllable and stable power ramp rate. Therefore, it is anticipated that the generator will not contribute to voltage fluctuations or flicker when connected in parallel with the grid.

3.3.5.2 SCTT Operation

Under SCTT operation of the generators(island mode), power quality could be an issue due to low fault levels at the LV network especially if there is any distorting or fluctuating loads at the LV network. This is inherent characteristics of standby operation and is not expected to be a problem when the generator is operated infrequently. Under peak lopping operation the generator is expected to operate longer and more frequent (daily). Hence the SCTT operation option of the generator reduces the power quality and it could be a concern when the load is sensitive to power quality issues (harmonics, voltage fluctuation/dip, etc)

3.3.5.3 Sequential Switching

Minor reduction in power quality is expected. Increase in voltage spikes during switching, however it is expected to be within quality standards.

3.3.5.4 HV Connection

No issues are anticipated in power quality

4 Part B – Case Study

Five case studies were identified based on the fault level constraints at low voltage level. Table D1 in Appendix D illustrates the existing fault levels at 11 kV and 415 V side and the head room between the calculated fault levels and Energy Australia design ratings For all sites.

The five identified sites were the subject of a more detailed investigation. Site visits were conducted to obtain generator and customer plant information. Each site was examined in detail for thermal constraints, voltage regulation issues, and fault level constraints.. Recommendations and budget cost estimates for conversion of generators at each site were presented.

4.1 Site #1 – 20 Bond St (1000 kVA) – Parallel Option

The customer is supplied at 415V via two Energy Australia substations: Exchange Centre Pitt St No.1 (S4015) and Exchange Centre Pitt St No.2 (S4016) respectively. Three parallel 11kV feeders from Dalley Street zone substation feed a single LV bus via separate 11000/433V transformers, each rated at 1000 kVA. The transformers connect to radial 11kV feeders via isolating and earthing switches, and to the LV bus via air type circuit breakers, refer to **Figure 3 and Figure 8**. Two generator sets (2X1000 kVA) provide emergency supply for the building. The site is a commercial building with maximum demand of 2366 kVA.

Each generator is connected to a separate main switchboard via 2000A automatic transfer circuit breaker (located at the 415 V switchboard). The automatic transfer circuit breaker (ATCB) automatically connects the load between the normal supply and emergency supply.

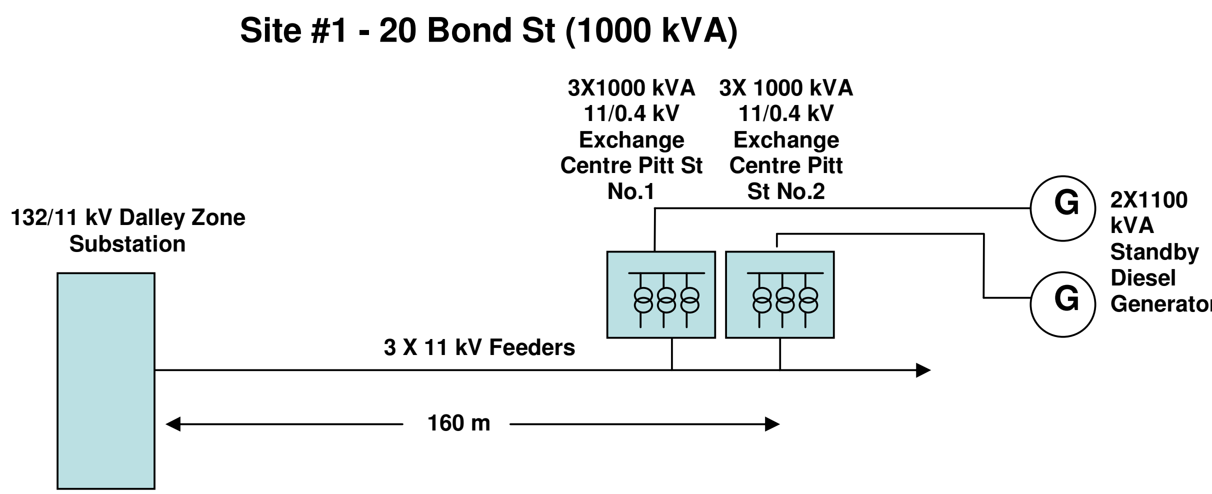

Figure 8: Single Line Diagram Illustrating the 11 kV Distribution System for Site #1 – 20 Bond St

4.1.1 Identified Options

1) Parallel Option – Under this option, it was found that only generator set No.2 could be used for peak lopping purposes due to fault level constraints on LV side of Exchange Centre Pitt St No.1 . The expected load reduction is up to 1100 kVA. (continuous kVA rating of the generator)

2) SCTT Option - The SCTT option is not feasible for this site as the standby generation (2X1100 kVA) is less than the peak load of the building 2366 kVA. Therefore this option will not be investigated further.

4.1.2 Option 1 – Parallel Operation

This option proposes to connect only one generator in parallel with Energy Australia LV switchboard due to fault level constraints. This would require additional protection and controls for the generator to allow safe parallel operation of the generator set. Upgrade work is required for the generating unit to allow for parallel operation.

4.1.2.1 Thermal Constraints

Due to the fact that the maximum generator output (1100 kVA) is less than the maximum existing load (2366 kVA) on the Exchange Centre Pitt St No.2, there are no anticipated issues with thermal constraints on the Energy Australia network as there is no power export when the generator is peak lopping. On the customer side, the rating of LV mains cable between to the LV terminal of the transformer and the LV switchboard is sufficient to carry up to full output of the generator.

It is anticipated that at times of less than maximum load, some export power from the generator to the 11kV grid will be available to reduce current flow and losses in adjacent parts of the Sydney CBD. To avoid possible uncertainty in metering the net power flow under such conditions, this option provides for revenue metering at the generator itself.

4.1.2.2 Voltage Constraints

In this section the effect of the generator connection on 415V and 11kV bus voltages is investigated.

Voltage rise may be defined as the difference between the steady-state voltage levels when the generator is connected (maximum generation output) and the voltage levels at zero-generation output. The zero-generation scenario is essentially identical to the existing system with no generator connected. Voltage rise is used as a planning criterion to gauge the effect of new plant on an existing distribution network.

Voltage step is the difference between the voltage level under normal operation and the (steady state) voltage level following a protective trip of the generator. The worst case voltage step occurs at maximum generator output, and is essentially the same as the voltage rise defined above, since a zero-generation scenario also reflects the system conditions after a generator trip.

The calculated voltage rise is equal to the product of the maximum per-unit generator current magnitude and the per-unit infeed impedance magnitude. The maximum voltage rise calculated at the Energy Australia 11kV and 415V busbars is presented in Table 2:

	Maximum voltage rise and step, %
Exchange Centre Pitt St No.2 11kV busbar	0.8
Exchange Centre Pitt St No.2 415V busbar	4.1

Table 2: Maximum voltage rise / voltage step (20 Bond St -1100 kVA)

The Energy Australia *Electricity Network Operation Standards* (July 2004) stipulate that operating voltages for LV distribution networks ideally remain between an upper limit of 438V (264V single phase) and a lower limit of 391V (226V single phase), although the operating voltage range may be larger under certain circumstances. These voltage limits correspond to a maximum deviation from nominal voltage of +5.5% to -5.8%. The *Standards* specify no firm limit on steady-state voltage changes, other than a 10% limit for voltage dips up to 10 seconds in duration for 'normal CBD supply'.

It is concluded that the maximum 4.1% voltage rise at the network point of common coupling is within acceptable limits, while the voltage rise at 11kV is comparatively insignificant. Therefore, it is unlikely to have an issue with voltage constraints.

4.1.2.3 Fault Level Constraints

Energy Australia indicated that the design fault rating of the LV equipment is 63 kA for substations of 3X1000 kVA and above and 50 kVA for all substation under 3X1000 kVA. The interruption capacity for the generator and the essential load switchgear is 65 kA.

Based on the existing fault level on 11 kV of Energy Australia Dalley St Zone substation and the transformers impedances, the fault level at LV bus was calculated. Table 3 illustrates a comparison between existing fault levels and the minimum design fault ratings to indicate the headroom left for the LV equipment.

Existing Fault Level at LV Bus (kA)	Minimum Design Fault Ratings at LV Bus (kA)	Available Headroom (kA)	Generator Contribution at LV Bus (kA)
53.3	63	9.7	8

Table 3: Fault Level, design fault ratings and generator contribution for 20 Bond St

It is noted from the table that the headroom is sufficient to accommodate the generator contribution. Therefore, it is concluded that no issues would be anticipated in terms of fault level constraints.

4.1.2.4 Power Quality Issues

It is anticipated that the contribution of the diesel generator to harmonic voltage distortion levels would be insignificant, since three-phase synchronous generators are not a significant source of harmonics. The connection to the network is unlikely to excite any resonance. Further study is not considered necessary, unless the background levels of harmonics or flicker are already problematic.

Diesel generators have controllable and stable power ramp rate. Therefore, it is anticipated that the generator will not contribute to voltage fluctuations or flicker when connected in parallel with the grid, except for unplanned trips.

Therefore, it is concluded that power quality will not be an issue for parallel operation of diesel generators.

4.1.2.5 Protection & Control Schemes

4.1.2.5.1 Existing Distribution Feeder Protection Scheme

The 11kV existing protection scheme (see Appendix A, drawing 2) consists of three 11kV supplies 31A, 31B, and 31C:

- Phase over current relays with input from 100:5 class 10P25 current transformers located adjacent to the 11kV terminals of the 11/0.433kV 1000kVA transformer with remote trip output to Dalley St Zone substation feeder;
- Dalley St Zone substation has instantaneous over current, time-delayed over current, and earth fault protection on feeder with back-up over current and earth fault protection;
- Remote trip from the zone substation trips corresponding 415V air circuit breaker at 11kV/415V substation whenever the 11kV feeder protection operates.

The substation is fed by 3 x 50% rated 11kV feeders. The design is fault tolerant and permits the disconnection of a single 11kV feeder at a time without interruption of customer low voltage mains supply. With such configuration, it is rare for mains supply to be lost. However blackouts have occurred in the past and this is one of the reasons for the planned increased in system redundancy levels. As operation of an island in the LV system is unlikely.

To mitigate the risk of back-feeding faults resulting in cascade operation of adjacent feeder protections, the existing protection scheme isolates the 11/0.4kV transformers with an intertrip between the 11kV and 400V circuit breaker protection. Therefore, it is not necessary to install Neutral voltage displacement protection which would require the installation of 11kV voltage transformers. It is recommended that sufficient back-up for the failure of the intertrip will be the installation of a G59 type loss of mains protection relay as part of the generator protection.

4.1.2.5.2 Generator Protection

Generator protection is recommended for the safe parallel or standby operation of the generator. Protection provided for a typical standby generator will generally be inadequate for parallel operation and will need to be upgraded to meet the requirements of the National Electricity Rules. Duplicate or complementary protection is required including the following as a minimum.

- Generator protection relay (may include control functions) including:
    - phase instantaneous and time-delayed over current;
    - instantaneous and time-delayed earth fault
    - reverse power
    - other standard generator protections
- Back-up over current protection relay including:
    - phase instantaneous and time-delayed over current;
    - instantaneous and time-delayed earth fault
- Anti-islanding (G59) relay including:
    - rate of change of frequency (ROCOF df/dt) or vector displacement

- under / over voltage
- under / over frequency.

- Primary and backup auxiliary tripping relays.
- D.C. battery-backed power supply..

Additional generator protection may be installed depending on the relative importance of the generator and manufacturer's recommendations. All of the above equipment may be installed in a single Generator Control and Protection panel. It is recommended that protections are wired as shown in Appendix A – Figure A1.

4.1.2.5.3 Generator Synchronising Controls

To allow parallel operation additional controls may be required:

- Synchronising and control panel as shown in Figure A1 complete with auto synchroniser;
- 3-phase metering current transformers;
- 3-phase generator voltage sensing inputs;
- Single phase or 3-phase bus voltage sensing inputs;
- Communications interface for remote control/monitoring; and
- Digital AVR compatible with the new controls.

The synchroniser may be accommodated along with the generator protections and d.c. supplies in a single panel per generator.

4.1.2.6 Generator(s) Operation and Maintenance Issues

The diesel generator typically consume around 0.3 litre/hour times its KW rating when operated around full capacity. The existing day tank capacity is 1000 Litters which is adequate to operate the generator (1100 kVA) only for up to 4 hours. The day tank is refilled from the main storage tank every time the generator is operated for emergency supply. (Typically the main storage tank capacity is 10 time the capacity of the day tank)

For this site, physical space is a definite obstacle to replace the fuel day tank. Therefore, it is recommended to maintain the existing day tank and consider the daily refill. This would require more frequent inspection and maintenance of the fuel transfer and level detection equipments.

The substation is fed by 3 x 50% rated 11kV feeders. The design permits the isolation of a single 11kV feeder at a time without interruption of customer low voltage supply. Modification to the 11kV system may be performed by isolation of one feeder at a time and does not present any special difficulties. Also standby generator will be out of service during control upgrade. Portable standby generators are recommended as a contingency.

Please refer to section 3.2.5 for more on the generator operation and maintenance issues.

4.1.2.7 Budget Costs

Table 4 shows the total budget cost for parallel option at +/- 20%. Please refer to Appendix B for detailed budget cost assessment including assumptions, exclusions and inclusions of items.

The budget costing is excluding the cost of maintenance and operation required for the fuel day tank.

Item	Amount ($)
Modification to Generator Control & Synch Panel & LV Switchgear	90,000
Engineering	20,000
Testing & Commissioning	20,000
Total	**130,000**

Table 4 Summary of Budget Cost Estimate of Parallel Option – 20 Bond St at +/- 20 %

4.2 Site #2 – 55 Market St

The customer is supplied at 415V via Energy Australia kiosk substation S6689: Pitt Market St No.2. Three parallel 11kV feeders from City South zone substation feed a single LV bus via separate 11000/433V transformers each rated at 1000 kVA. The transformers connect to radial 11kV feeders via isolating and earthing switches, and to the LV bus via air type circuit breakers, refer to **Figure 3 and Figure 9**.

Two generator sets (2X800 kVA) provide emergency supply for the building. It was found that only one generator set could be used for peak lopping purpose due to fault level constraints on LV side. The site is a commercial building with maximum demand of 1459 kVA.

The site can otherwise be supplied from City Central Zone Substation if the normally open switch is closed. This will parallel Site #2 with Site #5 as a good peak load reduction of (1.6 MVA) can be achieved at City Central Zone substation if this configuration is applicable.

Site #2 - 55 Market St (938 kVA)

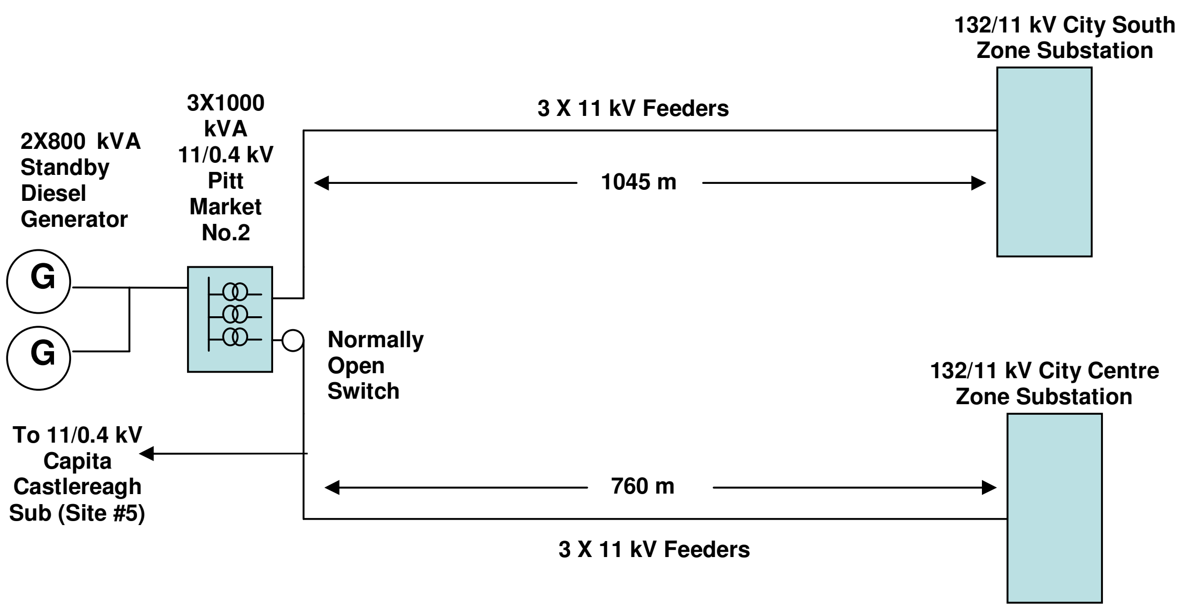

Figure 9: Single Line Diagram Illustrating the 11 kV Distribution System for Site #2 – 55 Market St

4.2.1 Identified Options

1) Parallel Option - It was found that only one generator set could be used for peak lopping purpose due to fault level constraints on LV side. Load reduction expected is up to 800 kVA

2) SCTT Option - The SCTT option is feasible for this site as the standby generation (2X800 kVA) is equivalent or greater than the peak load of the building 1459 kVA. Also this option considered feasible in terms of fault level constraints as the generators will not contribute to the fault levels at LV side, as the generators will only be connected to the network for a short time and then disconnected to operate in island mode. The expected load reduction is up to 1459 kVA

4.2.2 Option 1 – Parallel Operation

This option proposes to connect only one generator in parallel with Energy Australia LV switchboard due to fault level constraints. This would require islanding protection schemes and additional controls to allow safe parallel operation of the generator set. Upgrade work is required for the generating unit to allow for parallel operation.

4.2.2.1 Thermal Constraints

Due to the fact that the maximum generator output (800 kVA) is less than the maximum existing load of 1459 kVA (on the Pitt Market St No.2, there are no anticipated issues with thermal constraints on the Energy Australia network as there is no power export when the generator is peak lopping. On the customer side, the rating of LV mains cable between to the LV terminal of the transformer and the LV switchboard is sufficient to carry up to full output of the generator.

It is anticipated that at times of less than maximum load, some export power from the generator to the 11kV grid will be available to reduce current flow and losses in adjacent parts of the Sydney CBD. To avoid possible uncertainty in metering the net power flow under such conditions, this option provides for revenue metering at the generator itself.

4.2.2.2 Voltage Constraints

In this section the effect of the generator connection on 415V and 11kV bus voltages is investigated.

Voltage rise may be defined as the difference between the steady-state voltage levels when the generator is connected (maximum generation output) and the voltage levels at zero-generation output. The zero-generation scenario is essentially identical to the existing system with no generator connected. Voltage rise is used as a planning criterion to gauge the effect of new plant on an existing distribution network.

Voltage step is the difference between the voltage level under normal operation and the (steady state) voltage level following a protective trip of the generator. The worst case voltage step occurs at maximum generator output, and is essentially the same as the voltage rise defined above, since a zero-generation scenario also reflects the system conditions after a generator trip.

The calculated voltage rise is equal to the product of the maximum per-unit generator current magnitude and the per-unit infeed impedance magnitude. The maximum voltage rise calculated at the Energy Australia 11kV and 415V busbars is presented in Table 5 below:

	Maximum voltage rise and step, %
1 Pitt Market St No.2 11kV busbar	0.7
Pitt Market St No.2 415V busbar	3.5

Table 5: Maximum voltage rise / voltage step (55 Market St – 938 kVA)

The Energy Australia *Electricity Network Operation Standards* (July 2004) stipulate that operating voltages for LV distribution networks ideally remain between an upper limit of 438V (264V single phase) and a lower limit of 391V (226V single phase), although the operating voltage range may be larger under certain circumstances. These voltage limits correspond to a maximum deviation from nominal voltage of +5.5% to -5.8%. The *Standards* specify no firm limit on steady-state voltage changes, other than a 10% limit for voltage dips up to 10 seconds in duration for 'normal CBD supply'.

It is concluded that the maximum 3.5% voltage rise at the network point of common coupling is within acceptable limits, while the voltage rise at 11kV is comparatively insignificant. Therefore, it is unlikely to have an issue with voltage constraints.

4.2.2.3 Fault Level Constraints

Energy Australia indicated that the design fault rating of the LV equipment is 63 kA for substations of 3X1000 kVA and above and 50 kVA for all substation under 3X1000 kVA. The circuit breaker short current capacity for one of the two generators (Gen set 1) is 30 kA. The other generator's circuit breaker (Gen set 2) short circuit rating is at 65 kA.

Based on the existing fault level on 11 kV of Energy Australia City South Zone substation and the transformers impedances, the fault level at LV bus was calculated. Table 6 illustrates a comparison between existing fault levels and the minimum design fault ratings to indicate the headroom left for the LV equipment.

Existing Fault Level at LV Bus (kA)	Design Fault Ratings at LV Bus (kA)	Available Headroom (kA)	Generator Contribution at LV Bus (kA)
53.8	63	9.17	5.53

Table 6: Fault Level, design fault ratings and generator contribution for 55 Market St

It is noted from the table that the headroom is sufficient to accommodate the generator contribution. Therefore, it is concluded that no issues would be anticipated in terms of fault level constraints. It is recommended to connect Gen set 2 to avoid replacement of the existing circuit breaker to accommodate the increased fault levels.

4.2.2.4 Power Quality Issues

It is anticipated that the contribution of the diesel generator to harmonic voltage distortion levels would be insignificant, since three-phase synchronous generators are not a significant source of harmonics. The connection to the network is unlikely to excite any resonance. Further study is not considered necessary, unless the background levels of harmonics or flicker are already problematic.

Diesel generators have controllable and stable power ramp rate. Therefore, it is anticipated that the generator will not contribute to voltage fluctuations or flicker when connected in parallel with the grid, except for unplanned trips.

4.2.2.5 Protection & Control Schemes

Please see Section 4.1.2.5.

4.2.2.6 Generator(s) Operation and Maintenance Issues

The generator set would be expected to be operating daily for peak lopping. Therefore, the existing day and main tank system is required to accommodate the new requirements for fuel.

Only one day tank with capacity of 750 Litters was identified at the site. This capacity would be adequate to continuously operate the generator (800 kVA) only for up to 4 hours (based on typical consumption rate of 0.3 litre. kW/hour). The day tank is refilled from the main storage tank every time the generator is operated for emergency supply. (Typically the main storage tank capacity is 10 time the capacity of the day tank)

In order to facilitate the peak lopping operation of the generator, a larger capacity day tank is required to fulfil the new requirements for fuel. All the fuel transfer and detection equipments would be required to be upgraded to accommodate the new fuel capacity. No physical issues were identified. However, it is more cost effective to maintain the existing day tank and consider more frequent refilling from the main storage tank. This would require more frequent inspection and maintenance of the fuel transfer and level detection equipments.

The substation is fed by 3 x 50% rated 11kV feeders. The design permits the isolation of a single 11kV feeder at a time without interruption of customer low voltage supply. Modification to the 11kV system may be performed by isolation of one feeder at a time and does not present any special difficulties. Also standby generator will be out of service during control upgrade. Portable standby generators are recommended as a contingency.

Please refer to section 3.2.5 for more on the generator operation and maintenance issues.

4.2.2.7 Budget Cost

Refer to Table 4 for the total budget cost for parallel option at +/- 20%. Please refer to Appendix B for detailed budget cost assessment including assumptions, exclusions and inclusions of items.

4.2.3 Option 2 – SCTT Operation

This option proposes SCTT operation and adds an automatic remote start/stop capacity to facilitate peak load lopping.

Upgrade work is required for the generating unit to allow for SCTT mode of operation. No major network augmentation and protection schemes are required at 11 kV level as the generator will only be connected to the network for a short time of during load transfer.

4.2.3.1 Thermal Limits

The SCTT operation of the generator would not increase the 11 kV loading. The 415 V switchgear and switchboards can accommodate the maximum generator export.

4.2.3.2 Steady State Voltage Swing and Rise

The SCTT operation of the generating units is similar to the current standby operation in terms of network voltage issues. Therefore, it is anticipated that SCTT operation of this generator will not contribute to steady-state voltage rise problems.

4.2.3.3 Fault Levels

The generators will not contribute to existing fault levels in this option as the generators will be connected to the network for a short duration during load transfer.

4.2.3.4 Power Quality

The generator units will be connected to the network for short time during load transfer. Therefore, it is anticipated that the contribution of SCTT operated generator to harmonic levels in the network is insignificant.

Under SCTT operation of the generator, power quality may be an issue due to low fault levels at the LV network under islanding conditions, particularly if distorting or fluctuating loads are present on the LV network. This is an inherent characteristic of standby operation and is not expected to be a problem at this site.

4.2.3.5 Protection & Control Schemes

To allow SCTT operation of the two Generators, additional protections are not recommended, as paralleling with the mains is only for a short time during load transfer. The HLI for remote operation and interface for existing and new PLCs and controls is required.

The following additional controls will be required for both SCTT operating modes:

- Synchronising and control panel as shown in **Figure A1** complete with auto synchroniser;
- 3 phase metering current transformers;
- 3 phase generator voltage sensing inputs;
- Single phase mains and bus voltage sensing inputs;
- Digital AVR compatible with new controls;

- Communications interface for remote control/monitoring.

DC power supply for the controller may be taken from the generator start battery via a d.c. converter to provide isolation and hold-up voltage during generator starts. The HLI for remote operation and interface for existing and new PLCs and controls is required.

4.2.3.6 Operation and Maintenance Issues

Two generators exist on this site, only one generator operates for emergency supply, the other one is a back up generator. One fuel day tank system was noticed on the site which is set up for both generators, though it can not provide fuel for both generators in the same time. Under SCTT option two generators are expected to operate in the same time. Therefore, it is recommended that the existing day tank system be replaced by higher capacity system (double capacity).

The substation is fed by 3 x 50% rated 11kV feeders. The design permits the isolation of a single 11kV feeder at a time without interruption of customer low voltage supply. Modification to the 11kV system may be performed by isolation of one feeder at a time and does not present any special difficulties. Also standby generator will be out of service during control upgrade. Portable standby generators are recommended as a contingency.

Please refer to section 3.2.5 for more on the generator operation and maintenance issues.

4.2.3.7 Budget Costs

Table 7 shows the total budget cost for parallel option at +/- 20%. Please refer to Appendix B for detailed budget cost assessment including assumptions, exclusions and inclusions of items.

Item	Amount ($)
Modifications to Generator Control and Synch. Panel & LV Switchgear (SCTT Unit)	85,000
Day and Main Tank System Upgrade	65,000
Engineering	20,000
Testing & Commissioning	20,000
Total	**190,000**

Table 7 Summary of Budget Cost Estimate of SCTT Option – 55 Market St at +/- 20 %

4.3 Site #3 – 153 Clarence St

The customer is supplied at 415V via Energy Australia kiosk substations S3588: Red Cross Kent St. Three parallel 11kV feeders from City Central zone substation feed a single LV bus via separate 11000/433V transformers each rated at 1000 kVA. The transformers connect to radial 11kV feeders via isolating and earthing switches, and to the LV bus via air type circuit breakers, refer to **Figure 3 and Figure 10**.

One generator set (625 kVA) provides emergency supply for the building. The site is a commercial building with maximum demand of 1023 kVA. Therefore, the SCTT option is not feasible for this site as the standby generation is less than the peak load of the building. Parallel option will only be investigated for this site.

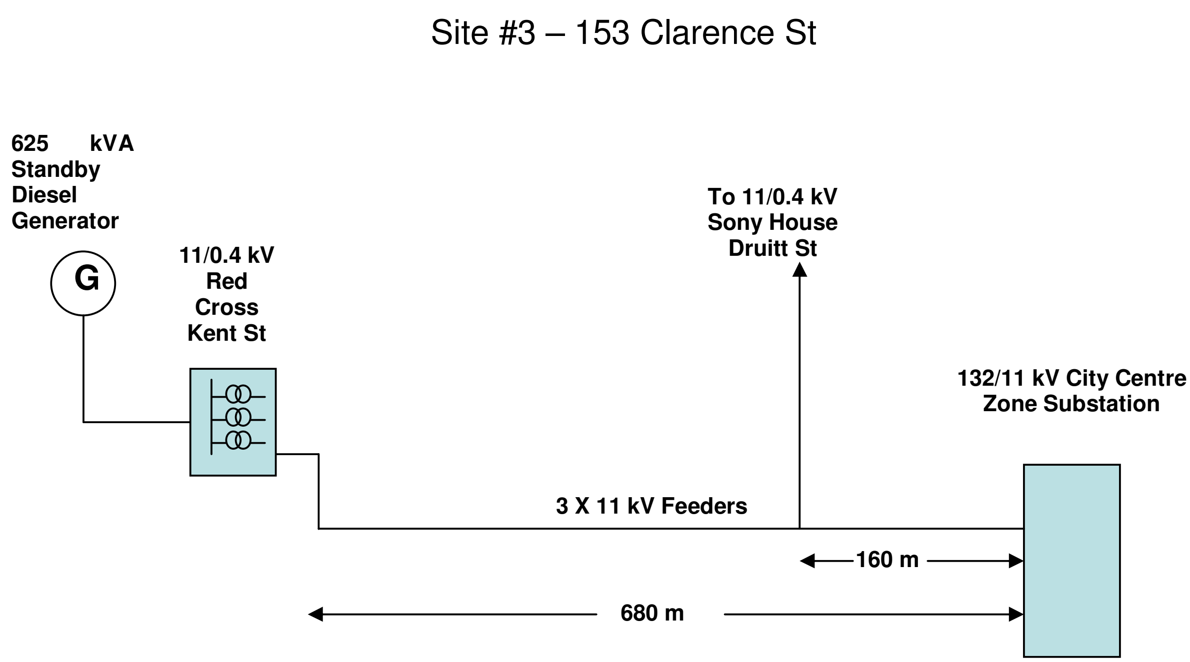

Figure 10: Single Line Diagram Illustrating the 11 kV Distribution System for Site #3 – 153 Clarence St

4.3.1 Identified Option

1) Parallel Option – This option was found feasible as the generator contribution will not cause any fault level constraints to the LV side. The load reduction expected is up to 625 kVA

2) SCTT Option - The SCTT option was found not feasible for this site as the standby generation (625 kVA) is less than the peak load of the building 1023 kVA. Therefore, this option is not investigated further.

4.3.2 Option 1 – Parallel Operation

4.3.2.1 Thermal Constraints

Due to the fact that the maximum generator output (625 kVA) is less than the maximum existing load of 1023 kVA (on the Red Cross Kent St Sub) , there are no anticipated issues with thermal constraints on the Energy Australia network as there is no power export when the generator is peak lopping. On the customer side, the rating of LV mains cable between to the LV terminal of the transformer and the LV switchboard is sufficient to carry up to full output of the generator.

It is anticipated that at times of less than maximum load, some export power from the generator to the 11kV grid will be available to reduce current flow and losses in adjacent parts of the Sydney CBD. To avoid possible uncertainty in metering the net power flow under such conditions, this option provides for revenue metering at the generator itself.

4.3.2.2 Voltage Constraints

In this section the effect of the generator connection on 415V and 11kV bus voltages is investigated.

Voltage rise may be defined as the difference between the steady-state voltage levels when the generator is connected (maximum generation output) and the voltage levels at zero-generation output. The zero-generation scenario is essentially identical to the existing system with no generator connected. Voltage rise is used as a planning criterion to gauge the effect of new plant on an existing distribution network.

Voltage step is the difference between the voltage level under normal operation and the (steady state) voltage level following a protective trip of the generator. The worst case voltage step occurs at maximum generator output, and is essentially the same as the voltage rise defined above, since a zero-generation scenario also reflects the system conditions after a generator trip.

The calculated voltage rise is equal to the product of the maximum per-unit generator current magnitude and the per-unit infeed impedance magnitude. The maximum voltage rise calculated at the Energy Australia 11kV and 415V busbars is presented in Table below:

	Maximum voltage rise and step, %
11kV busbar	0.5
415V busbar	2.23

Table 8: Maximum voltage rise / voltage step (153 Clarence St – 625 kVA)

The Energy Australia *Electricity Network Operation Standards* (July 2004) stipulate that operating voltages for LV distribution networks ideally remain between an upper limit of 438V (264V single phase) and a lower limit of 391V (226V single phase), although the operating voltage range may be larger under certain circumstances. These voltage limits correspond to a maximum deviation from nominal voltage of +5.5% to -5.8%. The *Standards* specify no firm limit on steady-state voltage changes, other than a 10% limit for voltage dips up to 10 seconds in duration for 'normal CBD supply'.

It is concluded that the maximum 2.23% voltage rise at the network point of common coupling is within acceptable limits, while the voltage rise at 11kV is comparatively insignificant. Therefore, it is unlikely to have an issue with voltage constraints.

4.3.2.3 Fault Level Constraints

Energy Australia indicated that the design fault rating of the LV equipment is 63 kA for substations of 3X1000 kVA and above and 50 kVA for all substation under 3X1000 kVA.

Based on the existing fault level on 11 kV of Energy Australia City Central Zone substation and the transformers impedances, the fault level at LV bus was calculated. Table 9 illustrates a comparison between existing fault levels and the design fault ratings to indicate the headroom left for the LV equipment.

Existing Fault Level at LV Bus (kA)	Minimum Design Fault Ratings at LV Bus (kA)	Available Headroom (kA)	Generator Contribution at LV Bus (kA)
57	63	5.8	5

Table 9: Fault Level, design fault ratings and generator contribution for 153 Clarence St

It is noted from the table that the headroom is sufficient to accommodate the generator contribution. Therefore, it is concluded that no issues would be anticipated in terms of fault level constraints.

4.3.2.4 Power Quality Issues

It is anticipated that the contribution of the diesel generator to harmonic voltage distortion levels would be insignificant, since three-phase synchronous generators are not a significant source of harmonics. The connection to the network is unlikely to excite any resonance. Further study is not considered necessary, unless the background levels of harmonics or flicker are already problematic.

Diesel generators have controllable and stable power ramp rate. Therefore, it is anticipated that the generator will not contribute to voltage fluctuations or flicker when connected in parallel with the grid, except for unplanned trips.

4.3.2.5 Protection and Control Scheme

Please see section 4.1.2.5

4.3.2.6 Generator Maintenance and Operation Issues

The existing day tank capacity is 1000 Litters which is adequate to continuously operate the generator (625 kVA) up to 6.5 hours. The day tank is refilled from the main storage tank every time the generator is operated for emergency supply. (Typically the main storage tank capacity is 10 time the capacity of the day tank)

It is recommended to maintain the existing day tank and consider the daily refill. This would require more frequent inspection and maintenance of the fuel transfer and level detection equipments.

The generator is located at a level below the level where pump machines are located. It is expected that the continuous and more frequent operation of the generator will cause an issue with vibration at the pump machines. It is recommended to relocate the pumps to a vibration free zone within that level. It is expected that the cost of this relocation would be around $ 50 k.

The substation is fed by 3 x 50% rated 11kV feeders. The design permits the isolation of a single 11kV feeder at a time without interruption of customer low voltage supply. Modification to the 11kV system may be performed by isolation of one feeder at a time and does not present any special difficulties. Also standby generator will be out of service during control upgrade. Portable standby generators are recommended as a contingency.

Please refer to section 3.2.5 for more on the generator operation and maintenance issues.

4.3.2.7 Budget Cost

Table 10 shows the total budget cost for parallel option at +/- 20%. Please refer to Appendix B for detailed budget cost assessment including assumptions, exclusions and inclusions of items.

Item	Amount ($)
Modification to Generator Control & Synch. Panel & LV Switchgear	90,000
Relocation of the pumps machines in the upper basement	50,000
Engineering	30,000
Testing & Commissioning	20,000
Total	**190,000**

Table 10 Summary of Budget Cost Estimate of Parallel Option – 153 Clarence St at +/- 20 %

4.4 Site #4 – 453-461 Kent St

The customer is supplied at 415V via Energy Australia kiosk substation S836: Sony House Druitt St. Three parallel 11kV feeders from City Central zone substation feed a single LV bus via separate 11000/433V transformers each rated at 400 kVA. The transformers connect to radial 11kV feeders via isolating and earthing switches, and to the LV bus via air type circuit breakers, refer to **Figure 4 and Figure 11**. One generator set (450 kVA) provides emergency supply for the building. The site is a commercial building with maximum demand of 411 kVA.

Site #4 – 453-461 Kent St

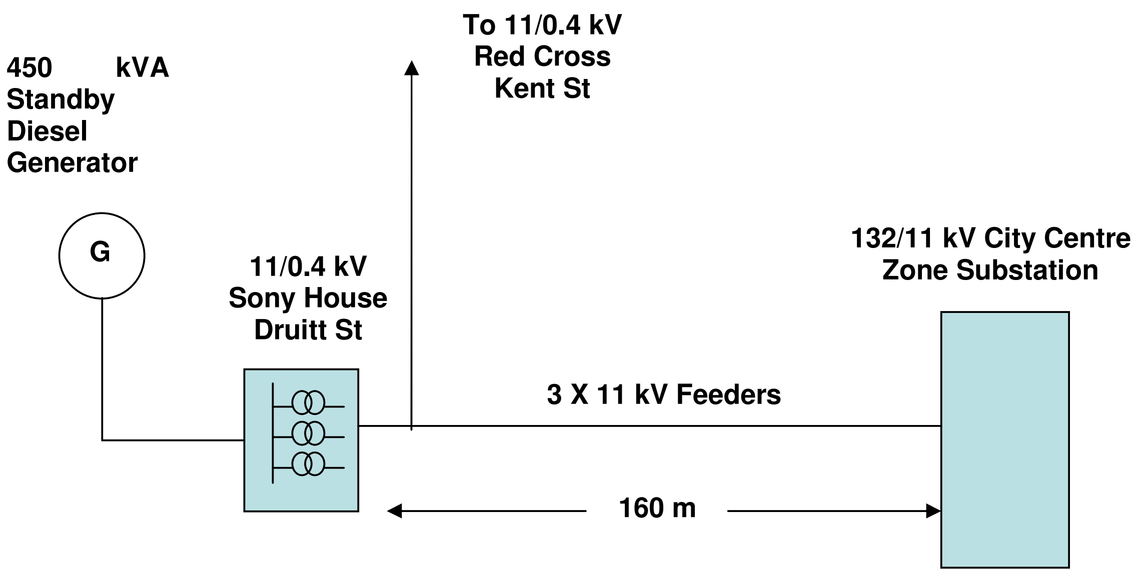

Figure 11: Single Line Diagram Illustrating the 11 kV Distribution System for Site #4 – 453 Kent St

4.4.1 Identified Option

Parallel Option – This option was found feasible as the generator contribution will not cause any fault level constraints to the LV side.

SCTT Option - The SCTT option is feasible for this site as the standby generation (450 kVA) is equivalent or greater than the peak load of the building 411 kVA.

4.4.2 Option 1 - Parallel Operation

4.4.2.1 Thermal Constraints

Due to the fact that the maximum generator output (450 kVA) is less than the maximum existing load of 1023 kVA (on the Red Cross Kent St Sub) , there are no anticipated issues with thermal constraints on the Energy Australia network as there is no power export when the generator is peak lopping. On the customer side, the rating of LV mains cable between to the LV terminal of the transformer and the LV switchboard is sufficient to carry up to full output of the generator.

It is anticipated that at times of less than maximum load, some export power from the generator to the 11kV grid will be available to reduce current flow and losses in adjacent parts of the Sydney CBD. To avoid possible uncertainty in metering the net power flow under such conditions, this option provides for revenue metering at the generator itself

4.4.2.2 Voltage Constraints

In this section the effect of the generator connection on 415V and 11kV bus voltages is investigated.

Voltage rise may be defined as the difference between the steady-state voltage levels when the generator is connected (maximum generation output) and the voltage levels at zero-generation output. The zero-generation scenario is essentially identical to the existing system with no generator connected. Voltage rise is used as a planning criterion to gauge the effect of new plant on an existing distribution network.

Voltage step is the difference between the voltage level under normal operation and the (steady state) voltage level following a protective trip of the generator. The worst case voltage step occurs at maximum generator output, and is essentially the same as the voltage rise defined above, since a zero-generation scenario also reflects the system conditions after a generator trip.

The calculated voltage rise is equal to the product of the maximum per-unit generator current magnitude and the per-unit infeed impedance magnitude. The maximum voltage rise calculated at the Energy Australia 11kV and 415V busbars is presented in Table below:

	Maximum voltage rise and step, %
11kV busbar	0.34
415V busbar	2.76

Table 11 : Maximum voltage rise / voltage step (453 Kent St – 450 kVA)

The Energy Australia *Electricity Network Operation Standards* (July 2004) stipulate that operating voltages for LV distribution networks ideally remain between an upper limit of 438V (264V single phase) and a lower limit of 391V (226V single phase), although the operating voltage range may be larger under certain circumstances. These voltage limits correspond to a maximum deviation from nominal voltage of +5.5% to -5.8%. The *Standards* specify no firm limit on steady-state voltage changes, other than a 10% limit for voltage dips up to 10 seconds in duration for 'normal CBD supply'.

It is concluded that the maximum 2.76% voltage rise at the network point of common coupling is within acceptable limits, while the voltage rise at 11kV is comparatively insignificant. Therefore, it is unlikely to have an issue with voltage constraints.

4.4.2.3 Fault Level Constraints

Energy Australia indicated that the design fault rating of the LV equipment is 63 kA for substations of 3X1000 kVA and above and 50 kA for all substation under 3X1000 kVA.

Based on the existing fault level on 11 kV of Energy Australia City Central Zone substation and the transformers impedances, the fault level at LV bus was calculated. Table 12 illustrates a comparison between existing fault levels and the design fault ratings to indicate the headroom left for the LV equipment.

Existing Fault Level at LV Bus (kA)	Minimum Design Fault Ratings at LV Bus (kA)	Available Headroom (kA)	Generator Contribution at LV Bus (kA)
34	50	16	2.6

Table 12: Fault Level, design fault ratings and generator contribution for 453 Kent St

It is noted from the table that the headroom is sufficient to accommodate the generator contribution. Therefore, it is concluded that no issues would be anticipated in terms of fault level constraints.

4.4.2.4 Power Quality Issues

It is anticipated that the contribution of the diesel generator to harmonic voltage distortion levels would be insignificant, since three-phase synchronous generators are not a significant source of harmonics. The connection to the network is unlikely to excite any resonance. Further study is not considered necessary, unless the background levels of harmonics or flicker are already problematic.

Diesel generators have controllable and stable power ramp rate. Therefore, it is anticipated that the generator will not contribute to voltage fluctuations or flicker when connected in parallel with the grid, except for unplanned trips.

4.4.2.5 Generator Maintenance and Operation Issues

The generator set has only one fuel tank with capacity of 1500 Litres. This capacity is adequate to continuously operate the generator (450 kVA) up to 11 hours. 11 hours are only adequate to operate the generator for few days when considering peak lopping application. Therefore, either weekly refill of the tank should be considered or a main tank system should be established. The high cost of main tank system and possible unavailability of physical space could make this generation site (450 kVA) infeasible.

It is recommended to maintain the existing fuel tank system and consider the daily refill. This would require additional cost for weekly fuel transfer.

The substation is fed by 3 x 50% rated 11kV feeders. The design permits the isolation of a single 11kV feeder at a time without interruption of customer low voltage supply. Modification to the 11kV system may be performed by isolation of one feeder at a time and does not present any special difficulties. Also standby generator will be out of service during control upgrade. Portable standby generators are recommended as a contingency.

Please refer to section 3.2.5 for more on the generator operation and maintenance issues.

4.4.2.6 Budget Costs

Table 13 shows the total budget cost for parallel option at +/- 20%. Please refer to Appendix B for detailed budget cost assessment including assumptions, exclusions and inclusions of items.

Item	Amount ($)
Modification to Generator Control & Synch. Panel & LV Switchgear	90,000
Engineering	20,000
Testing & Commissioning	20,000
Total	**130,000**

Table 13 Summary of Budget Cost Estimate of Parallel Option –453 Kent St at +/- 20 %

4.4.3 Option 2 - SCTT Option

This option proposes to SCTT operation and adds an automatic remote start/stop capacity to facilitate peak load lopping.

Upgrade work is required for the generating unit to allow for SCTT mode of operation. No major network augmentation and protection schemes are required at 11 kV level as the generator will only be connected to the network for a short time of during load transfer.

4.4.4 Thermal Limits

The SCTT operation of the generator would not increase the 11 kV loading. The 415 V switchgear and switchboards can accommodate the maximum generator export.

4.4.5 Steady State Voltage Rise

The SCTT operation of the generating units is similar to the current standby operation in terms of network voltage issues. Therefore, it is anticipated that SCTT operation of this generator will not contribute to steady-state voltage rise problems.

4.4.6 Fault Levels

The generators will not contribute to existing fault levels in this option as the generators will be connected to the network for a short duration during load transfer.

4.4.7 Power Quality

The generator units will be connected to the network for short time during load transfer. Therefore, it is anticipated that the contribution of SCTT operated generator to harmonic levels in the network is insignificant.

The generator unit will be connected to the network for short time during load transfer. Therefore, it is anticipated that flicker emission of the SCTT operated generator is insignificant.

Under SCTT operation of the generator, power quality may be an issue due to low fault levels at the LV network under islanding conditions, particularly if distorting or fluctuating loads are present on the LV network. This is an inherent characteristic of standby operation and is not expected to be a problem at this site.

4.4.7.1 Generator Maintenance and Operation Issues

Please refer to section 4.4.2.6

4.4.8 Protection & Control Schemes

To allow SCTT operation of the two Generators, additional protections are not recommended, as paralleling with the mains is only for a short time during load transfer. The HLI for remote operation and interface for existing PLCs and controls is required. Please refer to Section 4.1.3.5

4.4.9 Budget Costs

Table 14 shows the total budget cost for parallel option at +/- 20%. Please refer to Appendix B for detailed budget cost assessment including assumptions, exclusions and inclusions of items.

Item	Amount ($)
Modification to Generator Control and Synch. Panel & LV Switchgear (SCTT Unit)	40,000
Engineering	30,000
Testing & Commissioning	20,000
Total	**90,000**

Table 14 Summary of Budget Cost Estimate of SCTT Option –453 Kent St at +/- 20 %

4.5 Site #5 – 9 Castlereagh St

The customer is supplied at 415V via Energy Australia kiosk substations S6237: Capita Casetlereagh St. Three parallel 11kV feeders from City Central zone substation feed a single LV bus via separate 11000/433V transformers each rated at 1000 kVA. The transformers connect to radial 11kV feeders via isolating and earthing switches, and to the LV bus via air type circuit breakers, refer to **Figure 3 and Figure 12**. Three generator sets (3X750 kVA) provide emergency supply for the building. The site is a commercial building with maximum demand of 2255 kVA.

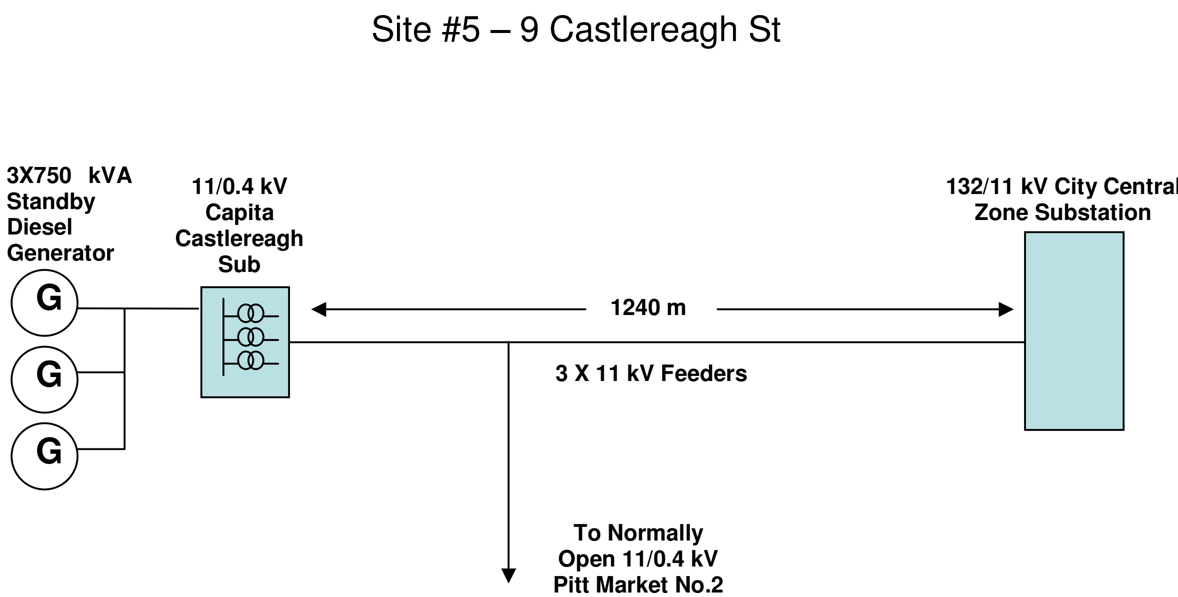

Figure 12: Single Line Diagram Illustrating the 11 kV Distribution System for Site #5 –9 Castlereagh St

4.5.1 Identified Options for Site #5 – 9 Castlereagh St

1) Parallel Option - It was found that only one generator set could be used for peak lopping purpose due to fault level constraints on LV side.

2) SCTT Option - The SCTT option was found not feasible for this site as the total standby generation (3X750 kVA) is less than the peak load of the building 2255 kVA. Therefore, this option is not investigated further.

4.5.2 Option 1 - Parallel Operation

4.5.2.1 Thermal Constraints

Due to the fact that the maximum generator output (625 kVA) is less than the maximum existing load of 1023 kVA (on the Red Cross Kent St Sub) , there are no anticipated issues with thermal constraints on the Energy Australia network as there is no power export when the generator is peak lopping. On the customer side, the rating of LV mains cable between to the LV terminal of the transformer and the LV switchboard is sufficient to carry up to full output of the generator.

It is anticipated that at times of less than maximum load, some export power from the generator to the 11kV grid will be available to reduce current flow and losses in adjacent parts of the Sydney CBD. To avoid possible uncertainty in metering the net power flow under such conditions, this option provides for revenue metering at the generator itself.

4.5.2.2 Voltage Constraints

In this section the effect of the generator connection on 415V and 11kV bus voltages is investigated.

Voltage rise may be defined as the difference between the steady-state voltage levels when the generator is connected (maximum generation output) and the voltage levels at zero-generation output. The zero-generation scenario is essentially identical to the existing system with no generator connected. Voltage rise is used as a planning criterion to gauge the effect of new plant on an existing distribution network.

Voltage step is the difference between the voltage level under normal operation and the (steady state) voltage level following a protective trip of the generator. The worst case voltage step occurs at maximum generator output, and is essentially the same as the voltage rise defined above, since a zero-generation scenario also reflects the system conditions after a generator trip.

The calculated voltage rise is equal to the product of the maximum per-unit generator current magnitude and the per-unit infeed impedance magnitude. The maximum voltage rise calculated at the Energy Australia 11kV and 415V busbars is presented in Table below:

	Maximum voltage rise and step, %
11kV busbar	0.6
415V busbar	2.6

Table 15: Maximum voltage rise / voltage step (9 Castlereagh St – 750 kVA)

The Energy Australia *Electricity Network Operation Standards* (July 2004) stipulate that operating voltages for LV distribution networks ideally remain between an upper limit of 438V (264V single phase) and a lower limit of 391V (226V single phase), although the operating voltage range may be larger under certain circumstances. These voltage limits correspond to a maximum deviation from nominal voltage of +5.5% to -5.8%. The *Standards* specify no firm limit on steady-state voltage changes, other than a 10% limit for voltage dips up to 10 seconds in duration for ‘normal CBD supply’.

It is concluded that the maximum 2.6% voltage rise at the network point of common coupling is within acceptable limits, while the voltage rise at 11kV is comparatively insignificant. Therefore, it is unlikely to have an issue with voltage constraints.

4.5.2.3 Fault Level Constraints

Energy Australia indicated that the design fault rating of the LV equipment is 63 kA for substations of 3X1000 kVA and above and 50 kVA for all substation under 3X1000 kVA. The interruption capacity for the generator and the essential load switchgear is 65 kA.

Based on the existing fault level on 11 kV of Energy Australia City Central Zone substation and the transformers impedances, the fault level at LV bus was calculated. Table 16 illustrates a comparison between existing fault levels and the design fault ratings to indicate the headroom left for the LV equipment.

Existing Fault Level at LV Bus (kA)	Minimum Design Fault Ratings at LV Bus (kA)	Available Headroom (kA)	Generator Contribution at LV Bus (kA)
57	63	5.8	5

Table 16: Fault Level, design fault ratings and generator contribution for 55 Market St

It is noted from the table that the headroom is sufficient to accommodate the generator contribution. Therefore, it is concluded that no issues would be anticipated in terms of fault level constraints.

4.5.2.4 Power Quality Issues

It is anticipated that the contribution of the diesel generator to harmonic voltage distortion levels would be insignificant, since three-phase synchronous generators are not a significant source of harmonics. The connection to the network is unlikely to excite any resonance. Further study is not considered necessary, unless the background levels of harmonics or flicker are already problematic.

Diesel generators have controllable and stable power ramp rate. Therefore, it is anticipated that the generator will not contribute to voltage fluctuations or flicker when connected in parallel with the grid, except for unplanned trips.

4.5.2.5 Generator Maintenance and Operation Issues

Only one day tank exists with capacity of 1000 Litre. The main storage tank capacity is 10,000 Litres. The fuel day tank provides immediate supply of fuel for the generator sets. Only one to two sets use the day tank at the same time. Therefore at least one day tank in addition to the existing day tank is required to provide the daily fuel for the three generators

The substation is fed by 3 x 50% rated 11kV feeders. The design permits the isolation of a single 11kV feeder at a time without interruption of customer low voltage supply. Modification to the 11kV system may be performed by isolation of one feeder at a time and does not present any special difficulties. Also standby generator will be out of service during control upgrade. Portable standby generators are recommended as a contingency.

Please refer to section 3.2.5 for more on the generator operation and maintenance issues.

4.5.2.6 Budget Cost

Table 17 shows the total budget cost for parallel option at +/- 20%. Please refer to Appendix B for detailed budget cost assessment including assumptions, exclusions and inclusions of items.

Item	**Amount ($)**
Modification to Generator Control and Synch. Panel & LV Switchgear	90,000
Day and Main Tank System Upgrade	65,000
Engineering	20,000
Testing & Commissioning	20,000
Total	**195,000**

Table 17 Summary of Budget Cost Estimate of Parallel Option for 9 Casltereagh St at +/- 20 %

5 Summary of Conclusions

5.1 Network and Generator Issues

The following were identified as issues:

1) **Fault Level Issues:** Fault levels in Sydney CBD distribution network are close to the design fault levels at LV level, please refer to Table D1 – Appendix D for 0.4 & 11 kV fault levels.

2) **Environmental Impact:** diesel-driven generators are high NOx emitters with typical NOx emissions equivalent to 13.5 to 19 kg/MWh, depending on the engine rating. Therefore appropriate management of NOx emissions will be required. Around 80% emission reductions can be achieved by installation of air pollution control equipment such as Selective Catalyst Reduction device also known as SCR.

3) **Generator Operation and Maintenance:** The diesel generator would be permitted to operate for only up to 200 hours/ year and up to 10 hours per time as required by the Protection of the Environment Operations Act 1997 and Energy Australia requirements for emergency supply operation (at contingency events).

   Existing day tanks (located at generator) are generally adequate to operate the generator for a few hours only and refilled automatically from the site main tank by the fuel system. Refilling of the main tank after each day of use will be required.

   When the hours of use exceed the recommended standard for standby use the life expectancy of the engine can be shortened considerably and the risk for premature failure is increased. Running the standby generator at its highest rating for longer hours will result in higher operating temperatures and reduce the life of the engine.

   Regular scheduled service is the key to extend the life of the engine and to maintain the performance. Diesel engine is due for maintenance every 200 – 250 hours if the engine is located in clean environment (no dust).

5.2 Generator Connection/Operation Options

The following options were identified for utilising the standby generator(s) for dispatchable demand reduction:

1) **HV Connection (Parallel Operation):** This option proposes connection of the generator(s) to the 11 kV side of the distribution substation, refer to Section 3.3.2.1. No technical issues are anticipated. The total demand reduction expected using this option for connection of the standby generators in Sydney CBD is 71 MVA. The connection cost per site could vary (AU$ 242,000 – AU$545,000), the cost varies depending on number of generators per site. A relationship between the connection cost rate (AU$/kVA) and the demand reduction size (kVA) is derived and presented in Figure 15

2) **LV Connection with Sequential Switching (Parallel Operation):** This option proposes the introduction of sequential switching controls to actively manage the LV fault levels at the distribution substation through the switching of one out of three of the redundant LV supplies to the distribution substation. The purpose of sequential switching is to reduce the LV fault level to permit the generator(s) LV connection. Refer to Figure 7 and Section 3.3.2.2. Disconnection of one-out-of-three supplies to the distribution substation will result

in reduced fault level and hence reduced power quality., However, the level of reduction is not expected to be a problem since the system is already designed for normal operation under this contingency. The total demand reduction expected using this option is 35 MVA. The cost per site is almost fixed at AU$190,000 when implementing this option on single distribution substation and up to three generators per site. Figure 15 shows the relation between the connection cost rate (AU$/kVA) and the size of the demand reduction (kVA)

3) **LV Connection (Parallel Operation):** This option involves the synchronisation and connection of the generator in parallel with the mains supply to permit export of power into the grid. This option is generally constrained by LV fault levels. Refer to Section 3.2.3. Only seven sites were identified feasible. The cost of modification required for generator synchronisation and control is almost flat at AU$ 90,000. The total of demand reduction from the feasible sites is 5 MVA.

4) **LV Connection (SCTT Operation):** The generator(s) will only be connected to the network for a short time during load transfer and then disconnected to operate in island mode. This option may be constrained by power quality issues and the generation capacity (less than the total peak demand of the customer). Refer to Section 3.2.2.

   Although lowest in cost of implementation, this option is not preferred and may be infeasible. The SCTT operation reduces the power quality of supply at LV side and it could be a concern when the customer is sensitive to power quality issues (harmonics, voltage fluctuation/dip, etc). For number of generation sites (especially with old generators), the existing generator control (AVR and the governor) could not be adequate to maintain the power quality up to the standards expected by the customer. To confirm the impact of the SCTT operation on the power quality further studies are recommended. For the generation sites where the total generation is less than the total load, reconfiguration of the LV system is required to implement SCTT. The reconfiguration can be achieved either by splitting the existing main switchboard into two bus sections: essential and non-essential, or installing new switchboard. Further information is required to identify the amount of essential load and non-essential load in order to identify the size of demand reduction and the design of the reconfiguration. Additional cost is likely to include:

   - Supply and installation of new LV switchgear
   - Modification to cabling to transfer load to new switchboard
   - Provision of temporary supply during works
   - New cabling between switchboards

   Further study will be required to confirm the feasibility of this option (in terms of physical space available to accommodate the changes).

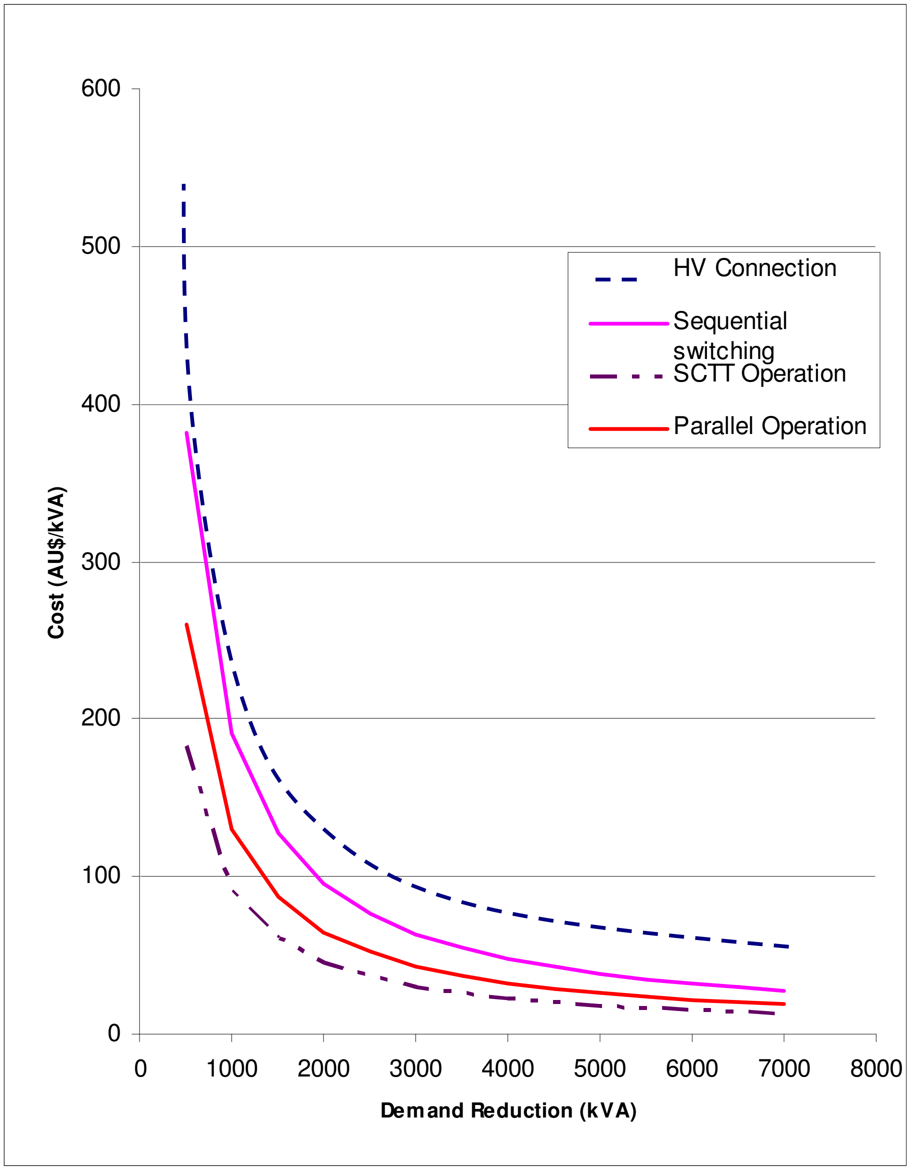

Figure 13: Connection cost (AU$/kVA) versus demand reduction (kVA) per site by connection option.

5.3 Demand Management Integrated Strategies

5.3.1 Integrated System for Generator Control

A strategy for central dispatch of the generators by DNSP was proposed (refer to Appendix C). This strategy will allow the generators to provide services to the DNSP such as relief in potential network overloads and also could provide ancillary services and reserve by aggregating a number of existing generators together under one contract and control scheme. The total cost estimate for implementation of such strategy on the five Sydney CBD zone substations and the 53 generation sites (excluding communication infrastructure between sites and zone substations) is AU$ 2.9m.

The minimum cost for a working system including: the central control room, one zone substation and a single customer components is AU$240k. The cost for connection of additional generators is AU$ 48,000.

5.3.2 Regulatory Tools

In order to meet the specific requirements of the Sydney CBD, i.e. to reduce the expected demand peak to avoid early system reinforcement at the zone substations and to avoid the risks of overloading the existing network equipment. The incentives outlined here would appear most appropriate:

- The incentive based demand response schemes, and in particular either the direct load control or the interruptible tariff mechanisms. The key question is whether a sufficient proportion of the avoided costs that would be saved by delaying these reinforcements can be offered as incentives to potential demand response providers to offset their initial installation and administration costs, as well as the ongoing operational and maintenance costs involved in maintaining either onsite generation or load reduction capability on permanent standby.
- Implementation of time of use tariffs and/or critical peak tariffs, if sufficiently high, would also help to reduce the levels of peak demand, though the level of reduction would depend on a number of factors outside the control of the utility and hence would be supplemental to rather than a replacement for direct load control or interruptible tariffs.
- The incentives to encourage distributed and renewable energy generation outlined here may possibly contribute to an overall reduction in the rate of load growth within the Sydney CBD. For example through the installation of photovoltaic cells on building roofs. However, they are unlikely to contribute significantly to peak reduction, due to the built up nature of the environment and the cost of retrofitting buildings with onsite generation.

5.3.3 Load Management

Two cost effective strategies that a building operator should consider for load management in order to respond to real-time prices are: thermostat control and control of lights.

5.3.4 Energy Storage Technologies

The following energy storage technologies are under development and should be watched for future demand management alternatives:

- The RFB may displace diesel generators by offering noise and smoke free operation. The RFB can operate as uninterruptible power supply (UPS). Switching is effectively instantaneous when loss of grid is detected. RFB stores energy during times of low demand and returning it to the grid at times of high demand.
- TES systems are applicable in most commercial and industrial facilities, but certain criteria must be met for economic feasibility. A system can be appropriate when maximum cooling load is significantly higher than average load.
- Hot Water/Steam accumulator is ideal as buffer storage for short time periods of several minutes, to compensate shading of the solar field by fast moving small clouds. Using appropriate encapsulated PCM (Phase Change Material) inside the storage could enhance

the storage capacity. PCM can be used to slow down the temperature and pressure decrease and enable smaller storage vessels for the same thermal capacity.

- SMES systems are designed to improve the power quality for critical loads and to provide carryover energy during voltage sags and momentary power outages. The system stores energy in a Superconducting coil immersed in liquid helium. It helps out overcome problems like sags, spikes, voltage and frequency instabilities.

6 Summary of Recommendations

6.1 Network and Generator Issues

Generator Operation and Maintenance - The frequent fuel refill requirements (once per day) may be a significant cost. This would require more frequent inspection and maintenance of the fuel transfer and level detection equipment as well a refill service.

Health, Safety and Environmental Impact - Appropriate management of CO2 and NOx emissions is recommended if widespread use of diesel generators for peak generation is proposed. This can be achieved by installation of air pollution control equipment such as Selective Catalyst Reduction devices also known as SCRs. The cost for a SCR system for diesel generators ranges from AUS$ 150,000 to AUS$200,000, depending on the size of the engine.

Risk Management – a formal risk assessment is recommended on a per site basis to evaluate the risk of supply interruption to critical loads. For parallel operation, this will include power systems analysis and transient stability studies.

Reliability – Run tests to confirm generator will function reliably for required duty and expected load variations.

6.2 Preferred Generator Connection Option

To achieve the best target for demand reduction (80 MVA), it is recommended that a combination of the HV connection option and LV Connection with Sequential Switching options is applied. Although SCTT appears more cost effective, it would only be technically feasible at a limited number of sites due to power quality constraints.

6.3 Load Management and Generator Dispatch SCADA System

An automatic control system with SCADA is recommended for control and monitoring of level of distributed generation. SCADA equipment will be located in the DNSP Central Control Room and each of the five DNSP Zone Substations.

The design requires further development to refine the cost estimate and to investigate the feasibility of interface with the existing SCADA system.

An investigation into the most suitable communication technology is recommended. It is expected that the use of existing mobile network, PSTN or DNSP fibre optics infrastructure will be the most cost effective solution.

7 References

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[4] Environ International Corporation,' Estimate of Emission for Small Scale Diesel Engines',2004

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[7] National Procurement Agency, Sri Lanka, Typical Technical Specifications for Diesel Generators 500 – 2000 kVA

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[9] Electricity Distribution Price Control Review: Final Proposals Ofgem NOVEMBER 2004

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[12] Introduction to the Greenhouse Gas Abatement Scheme (GGAS) IPART JULY 2006

[13] REDOX Flow Battery Energy Storage Device, S Bigham, Scottish Power, March 2006

[14] Thermal Energy Storage Strategies for Commercial HVAC Systems, PG&C

[15] Advanced electricity storage, technologies programme December 2005, Energy Storage Technologies: a review paper, Department of Environment and Heritage Australian Greenhouse Office.

8 Appendices

Appendix A – Generator Protection & Control

Figure A1 Generator protection and control single line diagram

Appendix B – Budget Estimate for the Five Case Studies

Table B1 – Budget Cost (+/- 20%) for Option 1 – Site #1 - 20 Bond St

Table B2– Budget Cost (+/- 20%) for Option 1 – Site #2 - 55 Market St

Table B3 – Budget Cost (+/- 20%) for Option 2 – Site #2 - 55 Market St

Table B4 – Budget Cost (+/- 20%) for Option 1 – Site #3 – 153 Clarence St

Table B5 – Budget Cost (+/- 20%) for Option 1 – Site #4 – 453 Kent St

Table B6 – Budget Cost (+/- 20%) for Option 2 – Site #4 – 453 Kent St

Table B7 – Budget Cost (+/- 20%) for Option 1 – Site #2 – 9 Castlereagh

Appendix C - Demand Management Integrated Strategy

Appendix D - Fault Level Information & Budget Estimates for HV Connection Option and 11 kV feeder Sequential Switching.

Table D1: Fault Levels at 0.4 & 11 kV sides of the Distribution Transformer for the Proposed Generation Sites

Table D2: Total budget cost for HV connection option for each site.

Table D3: The budget cost estimates for Sequential Switching Option for Each Site.

Figure D1: Single Line Diagram of HV Connection Design Option (Case 1A)

Figure D2: Single Line Diagram of HV Connection Design Option (Case 1B)

Figure D3 Single Line Diagram of HV Connection Design Option (Case 2)

Figure D4: Single Line Diagram of HV Connection Design Option (Case 3)

Appendix E – Technical Details and Cost Estimate for the Integrated System for Generator Control

Figure E1: Generator Control Topology

Alinta Quotation for the Integrated System for Generator Control

8.1 Appendix A

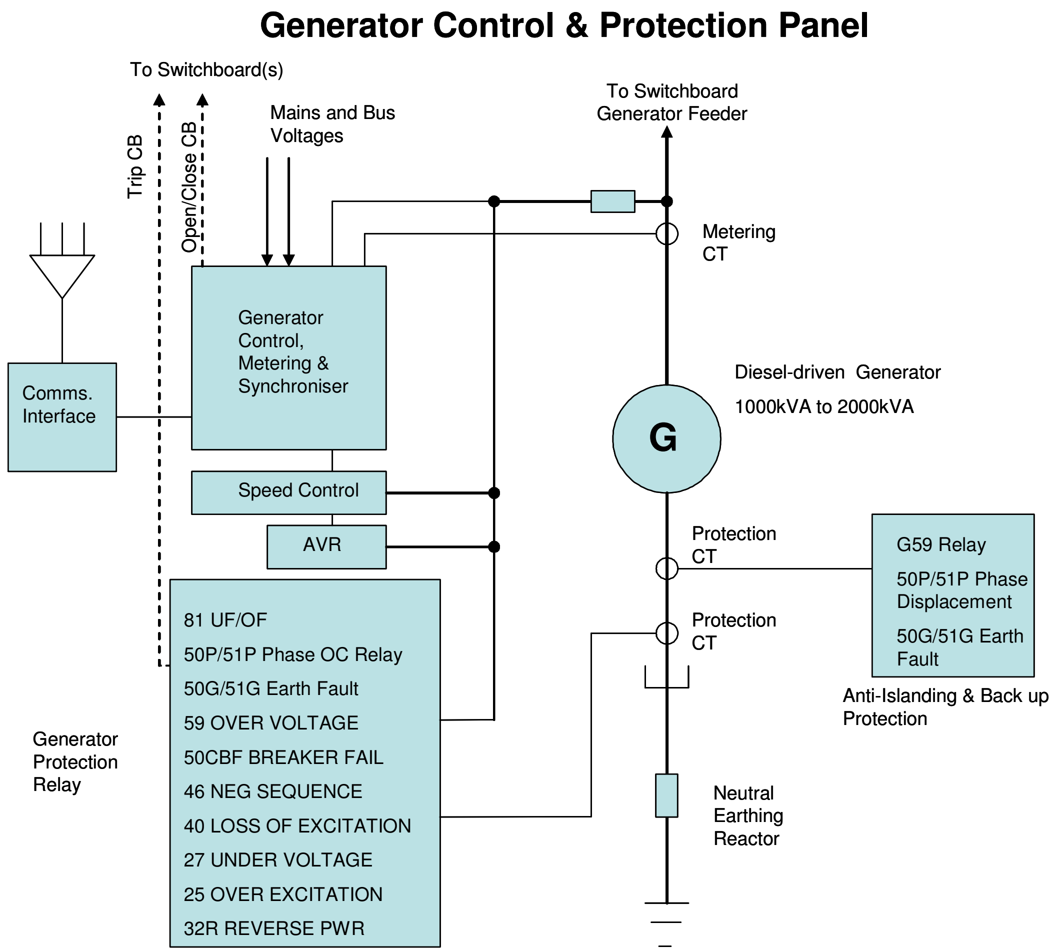

Figure A1: Generator protection and control single line diagram

8.2 Appendix B – Budget Estimate

8.2.1 General Notes, Assumptions and Exclusions

The budget cost for all sites has been based on the following assumptions and exclusions:

1) There is spare space for required additional indoor electrical panels housing the auto-synchronising and load management controls, protection and communications interface;
2) There is sufficient space in the Auto Transfer Switch panels to accommodate the required current transformers, voltage sensing points, watt transducer and control wiring;
3) Where grid export is possible, grid metering installation is capable of metering bi-directional power flows according to NEMMCO requirements;
4) There is sufficient spare capacity in existing cable trenches to accommodate additional control cables;
5) Power cables have been correctly selected to supply existing and forecast load levels at the site;
6) Remote-end monitoring, automatic control and communications equipment required by the Network Service Provider to initiate the remote start/stop of the generators has not been included. Communications lines or radio equipment are excluded. Communications interface at the local end only is included;
7) Operating and maintenance costs are excluded.
8) Maximum distance between generator and distribution substation is 50.

8.2.2 Budget Cost for Site#1 – 20 Bond St

8.2.2.1 Option 1 - Parallel Operation

Item	Unit Plant Cost ($)	Unit Labour Cost ($)	Qty	Amount ($)
Generator & LV Switchgear				
Diesel generator set modifications for parallel operation including neutral CTs, digital AVR & Protection.	6,000	2,500	1	8,500
Auto Synchroniser c/w, duplicated battery charger, remote control operation, and batteries, generator protection relay and over-current relay.	60,000	5,000	1	65,000
Auto Transfer Switch panel modifications including watt transducer, CTs, and fused voltage sensing connections.	5,000	5,000	1	10,000
Control and LV Cables, supports and terminations	5,000	2,500	1	7,500
Sub-total (Generator & LV Switchgear)				**91,000**
Engineering				20,000
Testing & Commissioning				20,000
Total				**131,000**

Table B1 – Budget Cost (+/- 20%) for Option 1 – Site #1 - 20 Bond St

8.2.3 Budget Cost for Site#2 – 55 Market St

8.2.3.1 Option 1 - Parallel Operation

Refer to Table B1

8.2.3.2 Option 2 - SCTT Operation

Item	Unit Plant Cost ($)	Unit Labour Cost ($)	Qty	Amount ($)
Generator & LV Switchgear (SCTT Unit)				
Diesel generator set modifications for SCTT operation including neutral CTs, Digital AVR.	4,000	2,000	2	12,000
Auto Synchroniser Panel c/w remote control communications interface,	15,000	5,000	2	40,000
Auto Transfer Switch panel modifications including watt transducer, CTs, and fused voltage sensing connections.	5,000	5,000	2	20,000
Control and LV Cables, supports and terminations	4,000	2,000	2	12,000
Sub-total - Generator & LV Switchgear (SCTT Unit)				
Day and Main Tank System Upgrade			1	64,000
Engineering				20,000
Testing & Commissioning				20,000
Total				**188,000**

Table B2 – Budget Cost (+/- 20%) for Option 1 – Site #2 - 55 Market St

8.2.4 Budget Cost for Site#3 – 153 Clarence St

8.2.4.1 Option 1 - Parallel Operation

Item	Unit Plant Cost ($)	Unit Labour Cost ($)	Qty	Amount ($)
Generator & LV Switchgear				
Diesel generator set modifications for parallel operation including neutral CTs, digital AVR & Protection.	6,000	2,500	1	8,500
Auto Synchroniser c/w, duplicated battery charger, remote control operation, and batteries, generator protection relay and over-current relay.	60,000	5,000	1	65,000
Auto Transfer Switch panel modifications including watt transducer, CTs, and fused voltage sensing connections.	5,000	5,000	1	10,000
Control and LV Cables, supports and terminations	5,000	2,500	1	7,500
Sub-total (Generator & LV Switchgear)				**91,000**
Relocation of the pumps machines in the upper basement				50,000
Engineering				30,000
Testing & Commissioning				20,000
Total				**201,000**

Table B3 – Budget Cost (+/- 20%) for Option 1 – Site #3 – 153 Clarence St

8.2.5 Budget Cost for Site#4 – 453 Kent St

8.2.5.1 Option 1 - Parallel Operation

Item	Unit Plant Cost ($)	Unit Labour Cost ($)	Qty	Amount ($)
Generator & LV Switchgear				
Diesel generator set modifications for parallel operation including neutral CTs, digital AVR & Protection.	6,000	2,500	1	8,500
Auto Synchroniser c/w, duplicated battery charger, remote control operation, and batteries, generator protection relay and over-current relay.	60,000	5,000	1	65,000
Auto Transfer Switch panel modifications including watt transducer, CTs, and fused voltage sensing connections.	5,000	5,000	1	10,000
Control and LV Cables, supports and terminations	5,000	2,500	1	7,500
Sub-total (Generator & LV Switchgear)				**91,000**
Engineering				20,000
Testing & Commissioning				20,000
Total				**131,000**

Table B4 – Budget Cost (+/- 20%) for Option 1 – Site #4 – 453 Kent St

8.2.5.2 Option 2 - SCTT Operation

Item	Unit Plant Cost ($)	Unit Labour Cost ($)	Qty	Amount ($)
Generator & LV Switchgear (SCTT Unit)				
Diesel generator set modifications for SCTT operation including neutral CTs, Digital AVR.	4,000	2,000	1	6,000
Auto Synchroniser Panel c/w remote control communications interface,	15,000	5,000	1	20,000
Auto Transfer Switch panel modifications including watt transducer, CTs, and fused voltage sensing connections.	5,000	5,000	1	10,000
Control and LV Cables, supports and terminations	4,000	2,000	1	6,000
Sub-total - Generator & LV Switchgear (SCTT Unit)				**42,000**
Engineering				30,000
Testing & Commissioning				20,000
Total				**92,000**

Table B5 – Budget Cost (+/- 20%) for Option 2 – Site #4 - 453 Kent St

Econnect

8.2.6 Budget Cost for Site#5 – 9 Castlereagh St

8.2.6.1 Option 1 - Parallel Operation

Item	Unit Plant Cost ($)	Unit Labour Cost ($)	Qty	Amount ($)
Generator & LV Switchgear				
Diesel generator set modifications for parallel operation including neutral CTs, digital AVR & Protection.	6,000	2,500	1	8,500
Auto Synchroniser c/w, duplicated battery charger, remote control operation, and batteries, generator protection relay and over-current relay.	60,000	5,000	1	65,000
Auto Transfer Switch panel modifications including watt transducer, CTs, and fused voltage sensing connections.	5,000	5,000	1	10,000
Control and LV Cables, supports and terminations	5,000	2,500		7,500
Sub-total (Generator & LV Switchgear)				**90,000**
Day and Main Tank System Upgrade			1	65,000
Engineering				20,000
Testing & Commissioning				20,000
Total				**195,000**

Table B5 – Budget Cost (+/- 20%) for Option 1 – Site #5 – 9 Castlereagh St

8.3 Appendix C - Demand Management Integrated Strategy

8.3.1 Schedule and Dispatch of Generators

The existing generators can provide services to the DNSP such as relief in potential network overloads and also could provide ancillary services and reserve by aggregating a number of existing generators together under one contract and control scheme

To efficiently achieve these objectives, two control strategies are identified:

8.3.1.1 Customer Control Strategy

Under this strategy, the customer starts its generator following instruction from utility in periods of network stress or network emergency conditions, based on number of incentive mechanisms, please refer to Section 5.2.1.1 for detailed explanation of these mechanisms. In most of these mechanisms the customer is obligated to respond to the network instruction and there will be penalties imposed on the customer if it does not.

However, the existing metering process at the customer side does not prove customer peak load reduction on daily bases. Also, penalties could not be enough to grantee the customer would perform load reduction at peak periods. In some mechanism the load reduction is voluntary and not an obligation, this makes customer control unpredictable and unreliable tool.

8.3.1.2 Direct Control Strategy by DNSP

Under this strategy, the DSNP has remote control of the operation of their standby generation. This control is activated during times of system stress to reduce exposure to price spikes or to alleviate potential network overloads. In return the consumer would receive a pre-agreed incentive payment or bill credit. The DNSP can efficiently achieve the response required as appropriate to the situation. The direct control of the generator is therefore more reliable to achieve demand reduction. The application of this strategy on Sydney CBD distribution network and existing generation sites is discussed further in section 5.1.2.1.

8.3.1.2.1 Direct Control Strategy Technical Considerations

The control philosophy of the proposed system is to mitigate the risk of overload in the five zone substations that supplies the Sydney CBD. The proposed system comprised an overload detection unit and a central controller at each zone substation. Also, a communications system and a number of generator controllers distributed around the generation sites.

The detection unit determines the power flow conditions at the Zone substation 11 kV Feeders, and send this information to the central controller. The central controller makes a decision based on this information, and sends control signals to switch generator controllers on or off as appropriate. Following the propagation of these signals from the central controller, the distributed generator controllers received and acted upon the control signals. Figure C1 & Figure E1, show the proposed architecture of the integrated system.

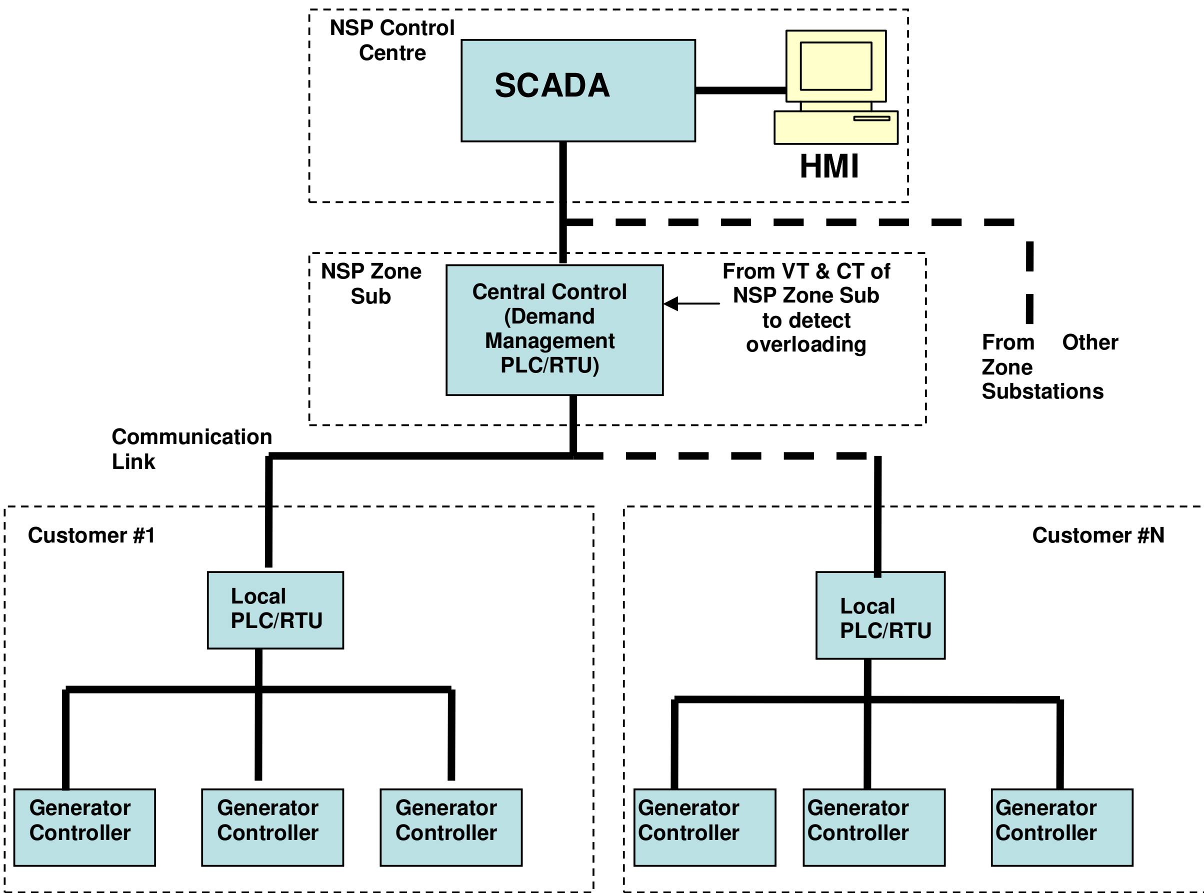

Figure C1: Block Diagram Illustrates the Proposed Generator Control System

Reliability of the communications in such system is important to ensure that the objectives of demand management are achieved. Failure to control a generator when required could result in increased import/export of energy from/to the grid and possibly an increase in energy costs.

A simple, low cost and reliable communications technology is required to transmit the control signals to the distributed load controllers. The following communication technologies can be considered to fulfil the requirements identified for the system:

- Public Switched Telephone Network (PSTN)
- Power Line Carrier (PLC)
- Mobile Communication (GSM)
- Radio communications technologies.
- Fibre Optics Communication Technology

PLC, GSM and radio could be more cost effective as these technologies do not require communication infrastructure between sites. However, using existing PSTN and fibre optics communication should be considered as low cost and reliable option.

8.3.1.2.2 Direct Control Strategy Commercial Consideration

Table C1 illustrates the cost estimate for the control system. The total cost estimate per site is around AUS $ 400,000. Please refer to Appendix E for more technical details on the proposed system including the hardware and software. Please also refer to the cost exclusions in Appendix E.

Item	**Cost (AUS $)**
Control System Hardware and Software (excluding per site hardware), including Communication Server, Peripheral I/O, HMI Software, Control Room Hardware, RTU Cubical and Hardware Application Licensing	189,000
Generator Controller Hardware and Installation (per site), including RTU Controller and Peripheral I/O	19,583
Other Per Site Costs, including Engineering & Configuration, Overhead and Commissioning	28,745
Other Costs (excluding per site costs), including main system Engineering & Configuration, Overhead and Test & Commissioning	162,000
Total Cost (per site)	399,328

Table C1 Budget Cost for Generator Control System

The other commercial consideration for this control scheme is that, the agreement between the DNSP and the customer would be likely to include payments both for availability and utilisation of output, along with penalty clauses for unavailability and non-delivery.

8.3.2 Regulatory Tools for Demand Management

The tools and incentives that have been used by utilities and regulators around the world to encourage sustainable energy solutions can be split into three broad areas, namely the incentives to reduce demand at times of system stress, the incentives designed to encourage the further implementation of distributed generation (i.e. generation that is connected closer to the sources of demand), and those incentives that are designed solely to encourage renewable or sustainable sources of energy generation. Each of these areas, along with the different types of incentives that each area requires, are discussed below.

8.3.2.1 Demand Response Incentives

The US Department of Energy defines demand response as

"Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized"[8]

The essence of this definition is that consumers are motivated to actively reduce their demand during periods of system stress either as a response to high prices, a response which can be difficult to predict and hence to plan for from a utility perspective, or as a much more predictable response to targeted incentive payments which the utility can instigate, measure, and plan for. Tools that can be used to trigger both responses are outlined below. In spirit each of these tools are designed to reduce load, which could either be by temporarily shutting down processes or load centres such as air conditioning units or by the activation of standby generation (in effect the scheduling of negative load).

Shutting down air conditioning systems for short periods of demand response is most effective in buildings that are thermally 'heavy' i.e. those buildings that have a high thermal inertia, and which only respond slowly to thermal inputs. In buildings that are thermally 'light', which is likely to include most of the office space in Sydney CBD, and that have large glazed areas, and hence high solar thermal gains, it is still possible to shut the air conditioning systems down for short periods of demand response, although this may need to be supported with additional measures, such as natural cooling of the building, shading of the windows, and provision of cold drinks, which have been proven to increase the thermal comfort of building occupants.

Operating standby generators in parallel with the utility network to offset load will require the installation of: -

- *Synchronisation Equipment*: - to enable the generator to automatically synchronise with the wider network. (This equipment may already be installed if there are multiple standby generators on the same site).
- *Communication & Control Equipment*: - to enable the standby generator to be started remotely or automatically depending on whether the activation is triggered by direct command or in response to price signals.
- *Protection Equipment*: - to ensure that the standby generation will not continue to feed power into the network in the event of a fault on the section of the network to which the generator is connected.

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[8] U.S, Department of Energy benefits of Demand Response in Electricity Markets and recommendations for achieving them FEBRUARY 2006

8.3.2.1.1 Incentive based demand response mechanisms

8.3.2.1.1.1 Direct Load Control

In effect this is where the utility has remote control of a proportion of the consumers load (for example any refrigeration or water heating plant), or potentially their standby generation, and can activate this control during times of system stress to reduce exposure to price spikes or as would be the case in the Sydney CBD to alleviate potential network overloads. In return the consumer would receive a pre-agreed incentive payment or bill credit. The advances in communication technologies and remotely controlled switchgear now mean that the need for expensive communication networks is no longer necessary as control can be wireless and that individual switches and hence individual consumers can be controlled, which means that the utility can fine tune the response required as appropriate to the situation, and also that the consumer can avoid repeated interruption as may be the case under a crude demand response scheme.

8.3.2.1.1.2 Interruptible / Curtailable tariffs

Rather than a remotely controlled load reduction, this scheme requires the consumer to agree to reduce their load by a set amount following instruction from the utility in periods of system stress. In exchange for the risk of interruption the consumer would receive a discounted tariff, or a credit towards their bill. Should the consumer not reduce their load to the agreed levels when instructed, then the utility would have the right under the agreement to impose penalty charges. This type of agreement normally also stipulates a minimum response time, a maximum duration for the load reduction and a maximum number of load reductions within a given time period.

8.3.2.1.1.3 Emergency Demand Response schemes

Similar to the interruptible tariff scheme, an emergency demand response scheme would offer an incentive payment to consumers who were willing to reduce their load when the system was under stress or subject to emergency conditions. However unlike the interruptible tariff scheme, reduction is voluntary, and the consumer can choose to maintain their load, and forego the incentive payment, without the risk of any further penalty. This has advantages for the consumer, but makes this an unpredictable and unreliable tool for the purposes of network planning and system operation.

8.3.2.1.1.4 Capacity Market mechanisms

This is a mechanism whereby the consumer receives guaranteed payments based on their ability to reduce load, irrespective of whether the load reductions are actually called for or not. In effect the consumer receives availability payments with the understanding that should the utility call for a demand reduction, the consumer is obligated to provide the service as defined in the agreement, which again is likely to list the load reduction required, duration of response, notification period etc, and that penalties will be imposed should the load reduction not conform to the agreement.

The agreement may also require the consumer to undertake a load reduction periodically to give the utility confidence that the required response will be provided when called for in extremis.

8.3.2.1.1.5 Demand bidding /buyback mechanisms

This mechanism is one of those used by the system operator in Great Britain, primarily to regulate frequency, but also to manage power flows. In effect consumers offer blocks of load reduction to the utility at a price at which the consumer would be willing to suffer the reduction. The utility can then instruct these reductions (and hence agree to pay the price quoted) should this be cheaper than any available alternate actions. This mechanism is primarily focused on offsetting price spikes, and has several limitations for use in the scenario presented in the Sydney CBD, namely that there is no guarantee the necessary load reductions will be bid at the required time, and that the utility will be exposed to the prices offered by the consumer.

8.3.2.1.1.6 Ancillary services

Ancillary services arrangements are similar in methodology to the capacity market based programs in that the consumer offers their load reduction capabilities to the utility for a fixed charge, which if competitive the utility then pays to keep the consumer on standby. The major difference between the two schemes is that rather than a fixed incentive payment, under ancillary services, in the event of the load reduction being called the consumer would receive the spot market energy price. The other difference is in the response time that the service may be called. Typically ancillary service contracts are required to bolster system reserve, and hence must be available within minutes rather than the hours required under some of the other demand response schemes. These contracts also tend to require larger volumes of load reduction and this combined with the short response times may rule out many of the sources of load earmarked for other schemes, however standby generators, particularly diesel generators such as those in the Sydney CBD, are ideally suited to this type of contract, because they can generally be started in less than two minutes.

8.3.2.2 Price based demand response mechanisms

In many utilities, including the distribution area serving Sydney CBD, there is a uniform tariff applied for demand consumers which does not take into account either peak load or geographic (and hence network) location, hence there is no price incentive for consumers to modify their behaviour in a way that would reduce the capacity constraints on the network. The following dynamic pricing mechanisms could be used to create more incentive for consumers to reduce their demand at times when wholesale prices are at their highest and network assets are under the most stress. In order for consumers to respond to these mechanisms it is necessary that the new tariff structures are clearly communicated to them, that they have the ability, i.e. the load reduction or onsite standby generation capability, and that they have meters that can record consumption by time of day so that the utility can charge accordingly. The disadvantage of these mechanisms form the perspective of application to the Sydney CBD is that the consumer response cannot be guaranteed, and hence would not necessarily obviate the need for network reinforcement.

8.3.2.2.1 Time of use tariffs

In simple form this basically means the introduction into the tariff structure of a peak and off-peak tariff, with the off peak tariff applying overnight and at weekends, and the peak tariff applying anywhere between 8am and 8pm. This mechanism is not limited to a two tariff structure but can be layered to incentives consumers to manage their demand as appropriate to the utility's requirements. For example to really focus the price signals, the peak tariff may only apply for a very short period over the actual demand peak, say between 4pm and 7pm, which would encourage consumers to specifically manage their consumption over this period.

8.3.2.2.1.1 Critical peak pricing

Critical peak pricing is a variation on time of use tariffs, which sets an extremely high tariff for those demand peaks which the utility deems are critical due to system stress or particularly high wholesale prices. These critical peaks would not be defined in advance in the tariff structure, (although the critical peak tariff would be specified in the structure), but would be called upon as required at short notice, within reasonable limits.

8.3.2.2.1.2 Real-time pricing

Real time pricing links supply tariffs directly to the wholesale price of electricity, thus exposing the consumer directly to the price peaks in the wholesale market, and creating an incentive to reduce consumption during these periods. As this is purely a price linked mechanism it is probably not suitable to the scenario within Sydney CBD. However there are generally two variants of real- time pricing

- **Day-ahead real-time pricing:** This is where consumers are notified a day in advance of the tariffs that will be applicable for the following twenty-four hours, which gives them the time to adjust their consumption accordingly either by shutting down processes or by running onsite generation.
- **Two-part real-time pricing:** This is where each consumer is allocated a historically based demand profile, and are then only exposed to the wholesale market prices should they significantly deviate above or below this demand profile. This scheme has the advantage to the consumer of reducing their exposure to the volatility of wholesale prices, and has the advantage to the utility of encouraging the consumer to ‘flatten’ their demand profile, i.e. replace peak load with off-peak load.

8.3.2.3 Distributed Generation Incentives

8.3.2.3.1 Distributed generation incentive for network operators

In its 2005 electricity distribution price control review, the GB regulator Ofgem introduced a 'hybrid' incentive scheme for DNSP's in Great Britain[9] with the objective to: -

- Encourage DNSP's to undertake the investment required to facilitate distributed generation connections (and generally be proactive and positive in responding to connection requests).
- Encourage DNSP's to invest efficiently and economically

To enable these objectives to be met, the hybrid incentive scheme allowed for: -

- The costs incurred by the DNSP's to provide network access to distributed generation are only partially allowed to be passed through directly to the customer through distribution use of system charges (the pass through rate is currently set at 80% of costs).
- The DNSP's to be given a supplementary £/kW revenue driver to incentivise the connection of distributed generation to the network (This incentive is currently set at £1.50/kW connected/year locked in for 15 years). The incentive to be recovered through generator distribution use of system (GDUoS) charges.
- An additional allowance of £1/kW connected/year to cover the ongoing operation and maintenance costs for these network access assets, also to be recovered through GDUoS charges.

8.3.2.3.2 Reduced connection charges for distributed generators

Traditionally in the UK, distributed generators have had to pay the total cost of both the assets necessary for their connection to the network and the cost of any reinforcements that were required to the network assets to allow the individual generator to export their power output, the so called 'deep' connection charging methodology.

In some cases the size of this combined capital expenditure was a significant barrier that prevented distributed generation projects from going ahead. Hence in an effort to remove or reduce this barrier the distribution charging methodology was reviewed and a 'shallowish' methodology introduced whereby the connecting generator now only pays for the proportion of the reinforcement cost that relates to the additional power flow and fault level increase that their connection will create. The remaining reinforcement cost is incorporated into the distribution use of system charges.

8.3.2.3.3 Pass through savings in transmission losses

When electrical energy is transferred in bulk across long distances of transmission and distribution networks, some energy is lost due to heating effects. This lost energy has a value which must be paid for ultimately by consumers. In the UK the liability for transmission losses is split between

[9] Electricity Distribution Price Control Review : Final Proposals Ofgem NOVEMBER 2004

delivering (generation) and off taking (supply); 45% is allocated to generators and 55% allocated to suppliers. However as distributed generation is effectively 'embedded' within distribution networks and hence is close to the sources of demand, a supplier can 'net off' the generation from the energy consumed by its customers, and hence reduce the aggregate amount of energy that is subject to transmission losses (reduce the off take). As an incentive, the supplier will then pass on a proportion of these savings to the distributed generator.

8.3.2.3.4 Pass through use of system charge savings

National Grid Electricity Transmission (NGET), as GB system operator, charges generators and suppliers for use of the GB transmission system via Transmission Network Use of System (TNUoS) charges.

Suppliers are charged on a maximum demand £/kW tariff where the kW amount is based on that customer's triad periods. The triad periods are defined as the half hour of demand peak and the two other half hours of highest demand which are separated from demand peak and each other by at least ten days. Therefore, when the output of a distributed generator is assigned to a supplier, any power produced by the generator during the triad periods has the effect of reducing the supplier's net demand.

The netting off of distributed generation reduces a supplier's exposure to demand TNUoS charges that would otherwise have been chargeable had the supplier contracted for transmission connected generation, and as with transmission losses, a proportion of these savings should be passed onto the generator.

8.3.2.3.5 Ancillary services

This is an area that is attracting increasing interest, particularly as the penetration of distributed generation increases, and as distribution networks themselves move from their traditionally passive network architecture and control systems, the so called 'fit and forget' policy, where the network is reinforced to cope with expected power flows and the active control inputs are generally at a high level, such as line drop compensation monitoring of the 132kV lines and auto-tapping of the 132/33kV transformers, to a much more active methodology, where alternatives to network reinforcement are considered if they are more cost effective, and the networks require active control inputs at a much lower level, for example to manage the voltage rise on individual 11kV distribution feeders in real time.

Distributed generators are ideally placed to participate and benefit from this requirement by providing ancillary services to the distribution network operators (DNSP) such as local voltage support, and network security (as would be the case in Sydney CBD), as well as services for the overall system operator such as frequency response and reserve by aggregating a number of distributed generators together under one contract and control scheme.

The value of the contract between the DNSP's and the distributed generator is likely to depend on the amount of control the DNSP requires over the generator output, and would be likely to include payments both for availability and utilisation of output, along with penalty clauses for unavailability and non-delivery.

8.3.2.4 Renewable Energy Incentives

Many countries around the world have introduced support mechanisms to encourage the development and implementation of renewable energy generation projects, however these support mechanisms tend to fall into one of the following five types: -

8.3.2.4.1 Feed-in tariffs

These exist in most member states of the European Union. They are characterised by a specific price, normally set for a period of several years, which must be paid by electricity companies (usually distributors) to domestic producers of renewable electricity. These schemes have the advantage of investment security, the possibility of fine tuning without affecting prior investments, and the promotion of technologies that are not cost effective in the short term. However there is a risk of over-funding.

8.3.2.4.2 Renewable energy certificates

This is the system that currently exists in the United Kingdom as well as four other European countries and is comparable to the MRET scheme in Australia. Under these systems, one renewable energy certificate is earned by the renewable energy producers for every MWh of renewable energy generated. Major consumers / suppliers are then obliged to purchase a certain number of renewable energy certificates from the renewable energy producers, according to a fixed percentage or quota of their total electricity consumption. Penalty payments for non-compliance are transferred to a specific fund or the general government budget or, in the case of the UK, are recycled to compliant generators / consumers.

In a recent report on support mechanisms in the EU[10], the European Commission commented

"Since producers / consumers wish to buy these certificates as cheaply as possible, a secondary market of certificates develops where renewable energy producers compete with one another to sell certificates. Therefore green certificates are market based instruments which have the theoretical potential if functioning well, of ensuring best value for investment. Green certificates have in theory a lower risk of over funding (compared to other support mechanisms) *but may pose a higher risk to investors and long-term, currently higher cost; technologies are not easily developed under such schemes. These systems also present higher administration costs".*

8.3.2.4.3 Tendering procedures

Pure tendering procedures used to exist in both Ireland and France, and also used to exist in the UK under the so called 'Non-Fossil Fuel Obligation' or 'NFFO' rounds. However both Ireland and France have changed or are changing to a feed-in tariff coupled with a tendering system.

Under a tendering process the state places a series of competitive tenders for the supply of renewable electricity. Successful tender parties then supply renewable energy on a contract basis and at a fixed price, for the term of the tender. The additional costs generated by the purchase of the renewable energy are passed onto the end consumer through a specific levy or else carried by the government and ultimately passed back to the taxpayer.

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[10] The support of electricity from renewable sources. The Commission of the European Communities 7th DECEMBER 2005

While tendering systems theoretically make optimum use of market forces, they can have a stop-go nature which is not conducive to stable investment conditions. It is also worth noting that tendering processes based solely on price have not been entirely successful, as a number of projects with low bids have yet to be built because the expected revenue is too low to justify the project going ahead.

However Canada has recently experimented with competitive tenders for 3000MW of wind generation. This tendering process was not based solely on price and considered a basket of factors of which price was only one.

For instance, they looked at how far advanced projects were in the consenting process, the experience of the developer in the wind industry and the likely ability of the developer to actually be able to go and successfully build the proposed development. They also sought a financial deposit from every developer which is only refunded in the event that a contract is not awarded, or if a contract is awarded, the project is successfully completed.

8.3.2.4.4 Tax incentives

Systems based purely on tax incentives are applied in Malta, Finland, and in the US with the Production Tax Credit. As it sounds the operator of a plant producing renewable energy can offset their tax bill based on a fixed credit for each kWh of renewable energy they produce. Some countries use tax incentives as an additional policy tool to encourage renewable energy.

8.3.2.4.5 Capital contributions

These incentives tend to be directed towards smaller renewable energy generation projects and involve a contribution from the state towards the initial capital cost of the project, in some cases linked to the installed capacity of the project. An example of this type of incentive is the recently announced California Solar Initiative[11] which makes an upfront capital contribution to solar energy projects below 100kW based on their installed capacity, with a feed in tariff arrangement based on actual energy produced for solar energy projects above 100kW capacity.

8.3.2.4.6 Greenhouse gas emission reduction schemes

Although not purely an incentive for the connection of generation, the incentive to reduce greenhouse gas emissions imposed by schemes such as the European Union's Emission Trading Scheme, where energy intensive industries are allocated a carbon emission allowance via a national allocation plan, and can then trade their surplus or shortfall with other participants, can be a supporting factor in the decision to install renewable energy generation onsite.

Indeed the encouragement of low carbon electricity generation is a key component of the New South Wales (NSW) Government's Greenhouse Gas Abatement Scheme[12] which imposes state wide greenhouse gas benchmarks on the participants in the electricity sector based on their share of the NSW electricity demand. The emission reduction activities that qualify for abatement certificates include: -

[11] California Solar Initiative fact sheet Public Utilities Commission State of California AUGUST 24th 2006
[12] Introduction to the Greenhouse Gas Abatement Scheme (GGAS) IPART JULY 2006

- Low emission generation of electricity or improvements in emission intensity of existing generation activities
- Activities that result in reduced consumption of electricity
- Activities that reduce on-site emissions not directly related to electricity consumption
- The capture of carbon from the atmosphere in forests

According to a recent report by the scheme administrator IPART[5], in 2005 just under eight million carbon abatement certificates were earned by low carbon generation, although only a small proportion of these certificates were attributable to onsite generation, while just over one and a half million certificates were earned through demand side abatement. One certificate is equivalent to one tonne of avoided carbon dioxide equivalent greenhouse gas emissions.

8.3.3 Other Demand Management Technologies

8.3.3.1 Other Generation Technologies - Combined Heat and Power Generation (CHP)

CHP (combined heat and power) is a very efficient technology for generating electricity and heat simultaneously, by using conventional generation technologies diesel engines, natural gas engines, steam turbines, gas turbines, micro-turbines and fuel cells,.

The heat generated in the process is utilised via heat recovery equipment for a variety of purposes including space heating.

CHP systems come in a range of sizes, from household-scale and up, but they are most feasible in larger commercial buildings.

Natural gas is the most popular fuel type used in existing CHP systems. However, CHP systems can run on a variety of fuels such as methane gas from landfills and biogas from agricultural operations.

Most CHP technologies are commercially available for on-site generation and combined heat and power applications. Several barriers, including network connection costs and issues and technology costs have kept these technologies from gaining wider acceptance. Many of the technologies are undergoing incremental improvements to decrease costs and emissions while increasing efficiency.

8.3.3.2 Load Management

8.3.3.2.1 Load Control Technologies

Light load Control

Generally, commercial buildings use big percentage of all electricity for lighting. To capture the energy savings possible from day lighting and other strategies in these buildings requires technology that is reliable and inexpensive enough to be retrofitted to commercial buildings.

An integrated-building equipment system (IBECS) was developed by Environmental Energy Technologies Division (EETD, USA, CA) in the past couple of years to allow facilities managers to automatically control devices such as lighting in commercial buildings, using a computer workstation and a wired network. However, it is not cost effective to add control wiring to the ceiling to control lighting loads.

IBECS was recently expanded to allow control of off-the-shelf Digitally Addressable Lighting Interface (DALI) ballasts, which are available in the marketplace now. This enhancement of IBECS allows facilities engineers to customize control systems for their buildings using commercially available lighting products.

A wireless networking technology that can effectively take advantage of daylight to reduce electric lighting energy use in buildings is under development by EETD. Researchers expect this technology to be widely used to enhance energy efficiency and environmental comfort in buildings once it appears on the marketplace which could be in just a few years.

Curtailment of HVAC loads

Load-curtailment strategies seek to adjust HVAC (heating, Ventilation, and Air Conditioning) temperature set points, or turn equipment off, in order to reduce load in ways that unavoidably reduce service. In order to achieve this effectively, a supervisory controller with an algorithm would be required to control the temperature set point during peak charge periods such that electricity charges were minimized. This means that the chillers are running at part load during peak periods []. However, there are some issues such as reliability of communication links between the central control and the thermostat or switches. Also the risk of that the strategy could affect the quality of the service.

Distributed Intelligent Load Controller (DILC)

Econnect has developed an innovative technology named Distributed Intelligent Load Controller (DILC) for distributed load management for managing site load on a grid-connected system. The main objective from such tool is to optimise the use of renewable energy,

This load management system could be used to create an additional demand for renewable energy. This would be achieved by switching heating loads from fossil fuel to renewable electricity when surplus renewable power was available. Although, this control technology could be complex, it could allow customers to reduce their energy bills and the supply companies to increase revenue.

8.3.3.2.2 Energy Storage Solutions for Load Management

Energy storage in an electricity generation and supply system enables the decoupling of electricity generation from demand. That is, electricity that can be produced at times of either low demand, low generation cost or from intermittent renewable energy sources is shifted in time for release at times of high demand, high generation cost or when no other generation is available. Appropriate integration of renewable energy sources with storage systems therefore will allow for greater market penetration, with associated primary energy and emissions savings.
Although electricity cannot be directly stored (at least cheaply), it can easily be stored in other forms and converted back to electricity when necessary. By decoupling the production and consumption of electricity, solutions to a wide range of energy supply needs can be offered provided that the capital cost, operating costs and reliability of the storage system are fully competitive with conventional systems. The most important features of energy storage systems are:

- Low cost penalty on the stored energy capital and low operation and maintenance costs
- Low occupational health and safety risks
- Low, or nil, environmental hazards in use or disposal.
- Simplicity of installation and relocation
- Small footprint for systems.

The energy storage technologies are found to be utilised in the following areas:

- Load Management
- Transmission and distribution facilities deferral
- Renewable energy management
- Power quality and reliability

- System stability
- Rapid reserve

Storage technologies for use in electricity systems can be classified by the form in which the storage occurs. A classification by type together with key examples is:

- Electrochemical Energy Storage – Redox Flow Battery (RFB)
- Thermal Energy Storage– Sensible Heat Systems
- Magnetic Energy Storage – Superconducting Magnetic Energy System
- Kinetic Energy Storage – Flywheels
- Potential Energy Storage – Pumped Hydro and Compressed Air

This section will focus only on the first three technologies due to their applicability to load management and other demand management objectives in commercial buildings.

8.3.3.2.3 Redox Flow Battery (RFB)

The RDF differs from its traditional lead-acid counterpart in that the power and energy parameters can be de-coupled: the power is determined by the size by the size of the battery and electrolyte flow rate whilst the energy stored is determined by the quantity of electrolyte in the adjacent tanks. The RFB is dc device which requires a Power Conversion System (PCS) in order to be charged by the ac distribution network and to supply ac back to the network. The installation of a five-hour flow battery would cost US$220 per kWh.[13]

The applications of RFB fall into standby power and supplementary power:

Standby power application: RFB provides power to an islanded section of network when there is loss of utility grid supply. The RFB may displace diesel generators by offering noise and smoke free operation. The RFB can operate as uninterruptible power supply (UPS). Switching is effectively instantaneous when loss of grid is detected.

Also RFB can operate as a standby generator which does not provide a power supply during a momentary interruption in grid power. Switching is manual or automatic but not instantaneous. Critical equipment such as computers or telecommunication devices may have a small separate UPS system to bridge an interruption of up to 20 minutes.

Supplementary power application: The RFB can provide power export onto the grid for network support during specific pre-defined periods. Some applications have been identified:

- Storage for Peak Lopping: RFB stores energy during times of low demand and returning it to the grid at times of high demand.
- Additional Capacity: RFB can be used on sections of network which is operating close to its capacity limits for some of the time, an RFB close to the main loads can ensure that the network capacity is not exceeded. It does this by cyclically charging when the feeder load is relatively low, and discharging when the load increases, in order to reduce the power flow along the feeder. This could defer the need for costly network reinforcement as local network loads increase.

[13] REDOX Flow Battery Energy Storage Device, S Bigham, Scottish Power, March 2006

- Storage for Renewable Energy: The RFB can help counteract any discrepancy between demand profile and availability of intermittent renewable power sources, such as wind and solar, by storing energy during times of excess, and returning it to the grid at times of scarcity.
- Quality of Supply: RFB can be used by customers who are critically sensitive to the quality of power supply to ride through voltage fluctuations.
- Contingency Planning: If there is a fault on the network requiring isolation of sections of network, RFB systems can provide supplementary power at points on the network where the grid supply requires temporary support or replacement while repairs are carried out.

8.3.3.2.4 Sensible Heat Systems

Thermal energy storage (TES) systems: shift cooling energy use to non-peak times. They chill storage media such as water, ice, or a phase-change material during periods of low cooling demand for use later to meet air-conditioning loads. TES systems are applicable in most commercial and industrial facilities, but certain criteria must be met for economic feasibility. A system can be appropriate when maximum cooling load is significantly higher than average load[14] [

The system consists of a storage medium in a tank, a packaged chiller or built-up refrigeration system, and interconnecting piping, pumps, and controls. The storage medium is generally water, ice, or a *phase-change*1 material (sometimes called a eutectic salt); it is typically chilled to lower temperatures than would be required for direct cooling to keep the storage tank size within economic limits. Figure C2 illustrates the basic operation of a system that uses chilled water.

These systems can be consuming more energy than no storage systems. This has often been true where demand reduction was the primary design objective. However, a number of design options can make TES systems more energy efficient than no storage systems [5].

[14] Thermal Energy Storage Strategies for Commercial HVAC Systems, PG&C

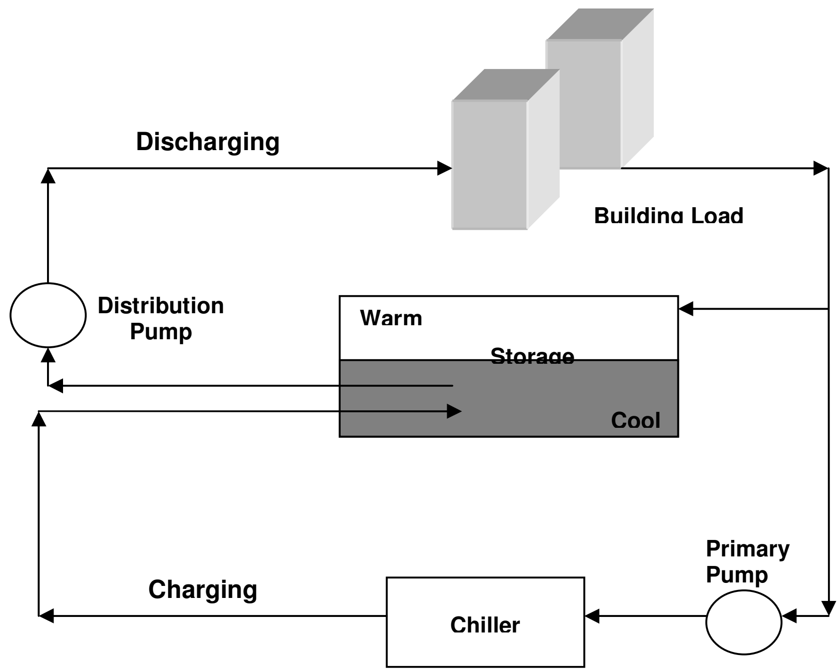


Figure C2 Thermal Energy Storage System

Steam or hot water Storage: [15]The steam drum, which is a common part in many steam generators, is often used to provide process heat storage in industry. The main problem is the size of the steam vessel for larger storage capacity and the degradation of steam quality during discharging. However, this storage type is ideal as buffer storage for short time periods of several minutes, to compensate shading of the solar field by fast moving small clouds. Using appropriate encapsulated PCM (Phase Change Material) inside the storage could enhance the storage capacity. PCM can be used to slow down the temperature and pressure decrease and enable smaller storage vessels for the same thermal capacity.

Recently, underground thermal energy storage has been proposed again as a low cost solution to high-temperature, low-loss thermal storage for CSP systems (Concentrating Solar Power). It involves storage of water under pressure in deep metal lined caverns where the pressure is contained by the surrounding rock and the overburden weight.

8.3.3.2.5 Superconducting Magnetic Energy System

Superconducting magnetic energy storage (SMES) system is a device for storing and instantaneously discharging large quantities of power. It stores energy in the magnetic field created by the flow of DC in a coil of superconducting material that has been cryogenically cooled. These systems have been in use for several years to improve industrial power quality and to provide a premium-quality service for individual customers vulnerable to voltage fluctuations. The SMES

15 Advanced electricity storage, technologies programme December 2005, Energy Storage Technologies: a review paper, Department of Environment and Heritage Australian Greenhouse Office.

recharges within minutes and can repeat the charge/discharge sequence thousands of times without any degradation of the magnet. Recharge time can be accelerated to meet specific requirements, depending on system capacity.

SMES systems are environmentally friendly because superconductivity does not produce a chemical reaction. In addition, there are no toxins produced in the process.

SMES can be used in enhancing transmission line capacity and performance. In a SMES system, energy is stored within a magnet that is capable of releasing megawatts of power within a fraction of cycle to replace a sudden lose in line power. Since the SMES recharges within minutes and can repeat the charge and discharge sequence thousands of times without any degradation of the magnet.

Some SMES systems are designed to improve the power quality for critical loads and to provide carryover energy during voltage sags and momentary power outages. The system stores energy in a Superconducting coil immersed in liquid helium. It helps out overcome problems like sags, spikes, voltage and frequency instabilities.

8.4 Appendix D – Fault Level Information & Budget Estimates for HV Connection Option and 11 kV feeder Sequential Switching.

Table D1: 0.4 kV & 11 kV Fault Levels

Building Name	Building Name	Sub Name	Zone Substation	11KV Feeder Nos:	Fault Level at 11 kV (kA)	Design Rating for 11kV Equipment (kA)	11 kV Headroom (kA)	Fault Level at 415 V (kA)	Design Rating for 415 V Equipment (kA)	Headroom (kA)	Generator Rating (KVA)	Generator Contribution (kA)
20	Bond St	Exchange Cent. Pitt St No1	Dalley Street	31A, 31B, 31C	9.65	18.40	8.75	63.65	63.00	-0.65		
20	Bond St	Exchange Cent. Pitt St No2	Dalley Street	31A, 31B, 31C	9.64	14.00	4.36	53.29	63.00	**9.71**	**1100.00**	**8.03***
20	Bridge St	Bridge Pitt	Dalley Street	33A, 33B, 33C	9.64			63.03	63.00			
20	Bridge St											
20	Bridge St											
50	Carrington St	Wynyard Ln Margaret	Dalley Street	35D, 35E, 35F	9.30	13.00	3.70	60.28	50.00	-10.28		

Building Name	Building Name	Sub Name	Zone Substation	11KV Feeder Nos:	Fault Level at 11 kV (kA)	Design Rating for 11kV Equipment (kA)	11 kV Headroom (kA)	Fault Level at 415 V (kA)	Design Rating for 415 V Equipment (kA)	Headroom (kA)	Generator Rating (KVA)	Generator Contribution (kA)
										0.00		
9	Castlereagh St	Capita Castlereagh St	City Central	55K, 55L, 55M	9.47			56.78	63.00	**6.22**	**750.00**	**6.02***
9	Castlereagh St											
9	Castlereagh St											
60	Castlereagh St	Elizabeth Martin Place	City Central	53A, 53B, 53C	8.98	11.00	2.02	71.01	63.00	-8.01		
60	Castlereagh St											
60	Castlereagh St											
159	Clarence St	Red Cross Kent St	City Central	56G, 56H, 56J	8.98	18.40	9.42	57.16	63.00	**5.84**	**625.00**	**4.83***

Building Name	Building Name	Sub Name	Zone Substation	11KV Feeder Nos:	Fault Level at 11 kV (kA)	Design Rating for 11kV Equipment (kA)	11 kV Headroom (kA)	Fault Level at 415 V (kA)	Design Rating for 415 V Equipment (kA)	Headroom (kA)	Generator Rating (KVA)	Generator Contribution (kA)
26-36	College St	Hargrave Francis	Campbell Street	PA19								
6-8	College St	Museum	Darlinghurst	PA14								
6	Dalley St	Telecom Underwood	Dalley Street	33G, 33H, 33J	9.82			63.12	63.00			
6	Dalley St											
161	Elizabeth St	Castlereagh & Market Sts	City South	45G, 45H, 45J	8.98	13.00	4.02	73.09	63.00	- 10.09		
1	Farrer Pl	Phillip & Bridge Streets	City East	21A, 21B, 21C								
1	Farrer Pl	Young Bent 30th Flr	Dalley Street	33A, 33B, 33C	9.55			62.98	63.00	0.02		
1	Farrer Pl	Young Bent 51st Flr	Dalley Street	33A, 33B, 33C	10.11							
1	Farrer Pl											
1	Farrer Pl											

Building Name	Building Name	Sub Name	Zone Substation	11KV Feeder Nos:	Fault Level at 11 kV (kA)	Design Rating for 11kV Equipment (kA)	11 kV Headroom (kA)	Fault Level at 415 V (kA)	Design Rating for 415 V Equipment (kA)	Headroom (kA)	Generator Rating (KVA)	Generator Contribution (kA)
1	Farrer Pl											
1	Farrer Pl											
259	George St	National Bk 16th Flr No1	Dalley Street	37K, 37L, 37M	9.22			53.72	63.00	**9.28**	**1100.00**	**10.60***
259	George St	National Bk 16th Flr No2	Dalley Street	34K, 34L, 34M	9.22			53.72	63.00	**9.28**	**1100.00**	**10.60**
259	George St											
259	George St											
363	George St	George Barrack 8th Flr	City Central	51K, 51L, 51M	9.30			72.68	63.00	-9.68		
363	George St											
363	George St											
363	George St											
400	George St	George King No1	City Central	54A, 54B, 54C	8.98	20.00	11.02	71.40	63.00	-8.40		

Building Name	Building Name	Sub Name	Zone Substation	11KV Feeder Nos:	Fault Level at 11 kV (kA)	Design Rating for 11kV Equipment (kA)	11 kV Headroom (kA)	Fault Level at 415 V (kA)	Design Rating for 415 V Equipment (kA)	Headroom (kA)	Generator Rating (KVA)	Generator Contribution (kA)
400	George St	George King No2	City Central	54A, 54B, 54C	8.98	20.00	11.02	71.40	63.00	-8.40		
580	George St	Wilmot George	City South	42G, 42H, 42J	9.38							
580	George St	Wilmot George 35th Flr	City South	42G, 42H, 42J	9.38							
580	George St											
264-278	George St	Aust Sq Bond St West	Dalley Street	31A, 31B, 31C	9.64	13.00	3.36	52.62	50.00	-2.62		
264-278	George St	Aust Sq Tower 19th Flr	Dalley Street	31A, 31B, 31C	9.64	15.75	6.11	52.26	50.00	-2.26		
264-278	George St	Aust Sq Tower 35th Flr	Dalley Street	31A, 31B, 31C	9.64	15.75	6.11	53.49	50.00	-3.49		
										0.00		
										0.00		
Fam. Crt	Goulburn St	Castlereagh Goulburn	City South	41A, 41B, 41C	8.91			53.59	63.00	**9.41**	**1200.00**	**11.56***

Building Name	Building Name	Sub Name	Zone Substation	11KV Feeder Nos:	Fault Level at 11 kV (kA)	Design Rating for 11kV Equipment (kA)	11 kV Headroom (kA)	Fault Level at 415 V (kA)	Design Rating for 415 V Equipment (kA)	Headroom (kA)	Generator Rating (KVA)	Generator Contribution (kA)
66	Harrington St	Archives Globe St	Dalley Street	33G, 33H, 33J	9.73							
66	Harrington St											
85	Harrington St	Archives Globe St	Dalley Street	33G, 33H, 33J	9.73							
1-7	Hay St	Market City No1	City South	46D, 46E, 46F	9.38							
1-7	Hay St	Market City No2	City South	46D, 46E, 46F	9.38							
309	Kent St	Grosvenor Bldg Sussex	City North	14A, 14B, 14C	3.71	18.75	15.04	48.59	50.00	**1.41**	**1375.00**	**13.25***
347	Kent St	Newtown Ln Sussex	City North	13D, 13E/1, 13F	9.30	20.00	10.70					
347	Kent St											

Building Name	Building Name	Sub Name	Zone Substation	11KV Feeder Nos:	Fault Level at 11 kV (kA)	Design Rating for 11kV Equipment (kA)	11 kV Headroom (kA)	Fault Level at 415 V (kA)	Design Rating for 415 V Equipment (kA)	Headroom (kA)	Generator Rating (KVA)	Generator Contribution (kA)
383	Kent St	Sussex Market	City Central	51K, 51L, 51M	9.47	20.00	10.53	73.62	63.00	-10.62		
201-207	Kent St	Kent Hickson No1	Dalley Street	31D, 31E, 31F	9.22							
201-207	Kent St	Kent Hickson No2	Dalley Street	31D, 31E, 31F	9.22							
242-246	Kent St	Telecom Clarence	City North	12A, 12B, 12C	3.71			63.37	63.00	-0.37		
242-246	Kent St											
242-246	Kent St											
453-461	Kent St	Sony House Druitt St	City Central	56G, 56H, 56J	8.98	14.00	5.02	34.04	50.00	**15.96**	**450.00**	**2.60***

Building Name	Building Name	Sub Name	Zone Substation	11KV Feeder Nos:	Fault Level at 11 kV (kA)	Design Rating for 11kV Equipment (kA)	11 kV Headroom (kA)	Fault Level at 415 V (kA)	Design Rating for 415 V Equipment (kA)	Headroom (kA)	Generator Rating (KVA)	Generator Contribution (kA)
135	King St	Carringbush & King Sts	Dalley Street	35A, 35B, 35C	9.64	20.00	10.36	64.34	63.00	-1.34		
135	King St											
26	Lee St	Lee Regent	Zetland	PA5								
20-24	Lee St	Lee Little Regent	Surry Hills	PA9								
1	Macquarie Pl	Gateway Plaza Pitt No1	Dalley Street	37D, 37E, 37F	9.22			62.80	63.00	0.20		
1	Macquarie Pl	Gateway Plaza Pitt No2	Dalley Street	37D, 37E, 37F	9.22			62.83	63.00	0.17		
1	Macquarie Pl											
1	Macquarie Pl											
1	Macquarie											

Building Name	Building Name	Sub Name	Zone Substation	11KV Feeder Nos:	Fault Level at 11 kV (kA)	Design Rating for 11kV Equipment (kA)	11 kV Headroom (kA)	Fault Level at 415 V (kA)	Design Rating for 415 V Equipment (kA)	Headroom (kA)	Generator Rating (KVA)	Generator Contribution (kA)
	Pl											
7-15	Macquarie St	Bennelong Macquarie No1	Dalley Street	33D, 33E, 33F	9.22			62.83	63.00	0.17		
7-15	Macquarie St	Bennelong Macquarie No2	Dalley Street	33D, 33E, 33F	9.22			62.83	63.00	0.17		
55	Market St	Pitt Market No2	City South	45K, 45L, 45M	9.47	20.00	10.53	53.82	63.00	**9.18**	**800.00**	**5.51***
55	Market St											
1	Market St	Kent & Market Sth No1	City Central	55A, 55B, 55C	8.91			53.59	63.00	**9.41**	**1100.00**	**10.60***
1	Market St	Kent & Market Sth No2	City Central	55A, 55B, 55C	8.91			53.59	63.00	**9.41**	**1100.00**	**10.60***
2	Market St	Market Kent No1	City Central	54K, 54L, 54M	9.47	18.40	8.93	60.68	63.00	**2.32**	**1375.00**	**13.25***
2	Market St	Market Kent No2	City Central	54K, 54L, 54M	9.47	20.00	10.53	56.78	63.00	**6.22**	**1375.00**	**13.25***

Building Name	Building Name	Sub Name	Zone Substation	11KV Feeder Nos:	Fault Level at 11 kV (kA)	Design Rating for 11kV Equipment (kA)	11 kV Headroom (kA)	Fault Level at 415 V (kA)	Design Rating for 415 V Equipment (kA)	Headroom (kA)	Generator Rating (KVA)	Generator Contribution (kA)
31	Market St	St Martins Tower Clarence	City Central	56K, 56L, 56M	9.38			55.16	50.00			
65-77	Market St	Market & Pitt Sts	City South	45K, 45L, 45M	9.91							
65-77	Market St	David Jones Castlereagh St	City South	42A, 42B, 42C	8.98	20.00	11.02	71.64	63.00	-8.64		
1	Martin Pl	Pitt & Martin No1	City North	14D, 14E, 14F	9.06			70.91	63.00	-7.91		
1	Martin Pl	Pitt & Martin No2	City North	14D, 14E, 14F	9.06			70.91	63.00	-7.91		
1	Martin Pl											
1	Martin Pl											
48	Martin Pl	C'wealth Bk Roof 10th Flr	City Central	55G, 55H, 55J	8.98			55.33	63.00	**7.67**	**1000.00**	**9.63***
48	Martin Pl											

Building Name	Building Name	Sub Name	Zone Substation	11KV Feeder Nos:	Fault Level at 11 kV (kA)	Design Rating for 11kV Equipment (kA)	11 kV Headroom (kA)	Fault Level at 415 V (kA)	Design Rating for 415 V Equipment (kA)	Headroom (kA)	Generator Rating (KVA)	Generator Contribution (kA)
38-46	Martin Pl	MLC Hosking Place	City Central	55G, 55H, 55J	8.98			54.98	63.00	**8.02**	**700.00**	**6.74***
5-17	Martin Pl	Commonwealth Rowe St	Dalley Street	31K, 31L, 31M	9.30	20.00	10.70	71.64	63.00	-8.64		
1	O'Connell St	Bent & Spring Sts	Dalley Street	37D, 37E, 37F	9.30			75.33	63.00	-12.33		
1	O'Connell St	Bent Spring 6th Level	Dalley Street	37D, 37E, 37F	9.30			56.63	63.00	**6.37**	**1875.00**	**18.06***
1	O'Connell St											
2	Park St	Park Pitt No1	City South	45A, 45B, 45C	8.98	20.00	11.02	70.86	63.00	-7.86		
2	Park St	Park Pitt 3rd Flr No1	City South	45A, 45B, 45C	9.38							
2	Park St	Park Pitt 3rd Flr No2	City South	45A, 45B, 45C	9.38							
2	Park St	Park Pitt 27th Flr	City South	45A, 45B, 45C	9.38							
88	Phillip St	Phillip Lane No1	City East	21A, 21B, 21C								

Building Name	Building Name	Sub Name	Zone Substation	11KV Feeder Nos:	Fault Level at 11 kV (kA)	Design Rating for 11kV Equipment (kA)	11 kV Headroom (kA)	Fault Level at 415 V (kA)	Design Rating for 415 V Equipment (kA)	Headroom (kA)	Generator Rating (KVA)	Generator Contribution (kA)
88	Phillip St	Phillip Lane No2	City East	21A, 21B, 21C								
88	Phillip St											
92-112	Phillip St	Chifley Square No1	City East	24D, 24E, 24F								
92-112	Phillip St	Chifley Square No2	City East	24D, 24E, 24F								
92-112	Phillip St	Chifley Square 43rd Flr	City East	24D, 24E, 24F								
92-112	Phillip St	Chifley Square 4th Flr	City East	24D, 24E, 24F								
92-112	Phillip St											
92-112	Phillip St											
76	Pitt St	PMG Pitt St	Dalley Street	32D, 32E, 32F	9.30	15.75	6.45	64.53	63.00	-1.53		

Building Name	Building Name	Sub Name	Zone Substation	11KV Feeder Nos:	Fault Level at 11 kV (kA)	Design Rating for 11kV Equipment (kA)	11 kV Headroom (kA)	Fault Level at 415 V (kA)	Design Rating for 415 V Equipment (kA)	Headroom (kA)	Generator Rating (KVA)	Generator Contribution (kA)
76	Pitt St	PMG Pitt St No2	Dalley Street	35A, 35B, 35C	9.64	20.00	10.36	73.75	63.00	-10.75		
76	Pitt St							0.00				
								0.00				
123	Pitt St	Angel Ash No1	Dalley Street	35D, 35E, 35F	9.30			71.01	63.00	-8.01		
123	Pitt St	Angel Ash No2	Dalley Street	35D, 35E, 35F	9.30			72.68	63.00	-9.68		
320	Pitt St	Telecom Pitt Central	City Central	52D, 52E, 52F	9.38			55.16	50.00	-5.16		
320	Pitt St	PMG Castlereagh St	City South	45K, 45L, 45M	9.38			55.16	50.00	-5.16		
477	Pitt St	Pitt Barlow No1	City South	46G, 46H, 46J	8.98	18.40	9.42	67.90	63.00	-4.90		
338-348	Pitt St	Dungate Ln Castlereagh	City South	41G, 41H, 41J	8.91			54.95	50.00	-4.95		

Building Name	Building Name	Sub Name	Zone Substation	11KV Feeder Nos:	Fault Level at 11 kV (kA)	Design Rating for 11kV Equipment (kA)	11 kV Headroom (kA)	Fault Level at 415 V (kA)	Design Rating for 415 V Equipment (kA)	Headroom (kA)	Generator Rating (KVA)	Generator Contribution (kA)
QVB	PO Box Q292, QVB post office NSW 1230	Queen Victoria Bldg	City South	42G, 42H, 42J	8.91			54.95	50.00	-4.95		
140	Sussex St	Sussex Marks Ln	City North	11A, 11B, 11C	3.71	20.00	16.29	62.51	63.00	0.49	900.00	6.50
201	Sussex St	Day Sussex No1	City Central	53G, 53H, 53J	8.98	20.00	11.02	69.20	63.00	-6.20		
201	Sussex St	Day Sussex No2	City Central	53G, 53H, 53J	9.38	20.00	10.62					
103-109	York St	National Mutual No1	City Central	56K, 56L, 56M	9.47	18.40	8.93	70.97	63.00	-7.97		
103-109	York St	National Mutual No2	City Central	56K, 56L, 56M	9.47	18.40	8.93	53.69	63.00	**9.31**	**725.00**	**6.98***

* The bold green refers to feasible sites. **All bold red and green refers to available headroom. *The bold red refers to unfeasible sites despite of availability of good headroom

Table D2: HV Connection Cost Estimate

Building Name	Building Name	Standby Rating (kVA)	Total Connection Cost (AUS$)	Total kVA
20	Bond St	1000.00	545,200	2000
20	Bond St	1000.00		
20	Bridge St			
20	Bridge St			
20	Bridge St			
50	Carrington St	1457	258,415	1457
9	Castlereagh St	750.00	194,615	2250
9	Castlereagh St	750.00		
9	Castlereagh St	750.00		
60	Castlereagh St	1000.00	210,815	3000
60	Castlereagh St	1000.00		
60	Castlereagh St	1000.00		
159	Clarence St	625	242,215	625
26-36	College St			
6-8	College St	600.00	242,215	600
6	Dalley St			
6	Dalley St			
161	Elizabeth St	550	242,215	550
1	Farrer Pl			
1	Farrer Pl			
1	Farrer Pl			
1	Farrer Pl			
1	Farrer Pl			
1	Farrer Pl			
1	Farrer Pl			

Building Name	Building Name	Standby Rating (kVA)	Total Connection Cost (AUS$)	Total kVA
259	George St			
259	George St			
259	George St			
259	George St			
363	George St	550.00	243,215	4200
363	George St	1400.00		
363	George St	1400.00		
363	George St	1400.00		
400	George St	1950	410,630	3900
400	George St	1950		
580	George St			
580	George St			
580	George St			
264-278	George St	1200.00	433,245	3600
264-278	George St	1200.00		
264-278	George St	1200.00		
Fam. Crt	Goulburn St			
66	Harrington St			
66	Harrington St			
85	Harrington St			
1-7	Hay St			
1-7	Hay St			
309	Kent St	1375.00	258,415	1375
347	Kent St	845.00	410,630	1545
347	Kent St	700.00		
383	Kent St	1500.00		1500

Building Name	Building Name	Standby Rating (kVA)	Total Connection Cost (AUS$)	Total kVA
201-207	Kent St			
201-207	Kent St			
242-246	Kent St	1300	243,215	3925
242-246	Kent St	1625.00		
242-246	Kent St	1000.00		
453-461	Kent St	450.00	242,215	450
135	King St	1100.00	250,815	2115
135	King St	1015.00		
26	Lee St			
20-24	Lee St			
1	Macquarie Pl			
1	Macquarie Pl			
1	Macquarie Pl			
1	Macquarie Pl			
1	Macquarie Pl			
7-15	Macquarie St			
7-15	Macquarie St			
55	Market St	800.00	229,215	1600
55	Market St	800.00		
1	Market St			
1	Market St			
2	Market St	1375.00	367,430	2750
2	Market St	1375		
31	Market St			
65-77	Market St	1150.00		

Building Name	Building Name	Standby Rating (kVA)	Total Connection Cost (AUS$)	Total kVA
65-77	Market St	1150	218,415	1150
1	Martin Pl	1750.00	395,430	7000
1	Martin Pl	1750.00		
1	Martin Pl	1750.00		
1	Martin Pl	1750.00		
48	Martin Pl	1000.00	229,215	2000
48	Martin Pl	1000.00		
38-46	Martin Pl	700.00	247,615	700
5-17	Martin Pl	1875.00	269,215	1875
1	O'Connell St	1875.00	327,430	5625
1	O'Connell St	1875.00		
1	O'Connell St	1875.00		
2	Park St	1000	477,460	4000
2	Park St	1000.00		
2	Park St	1000.00		
2	Park St	1000.00		
88	Phillip St			
88	Phillip St			
88	Phillip St			
92-112	Phillip St			
92-112	Phillip St			
92-112	Phillip St			
92-112	Phillip St			
92-112	Phillip St			
92-112	Phillip St			
76	Pitt St	1800.00	403,030	5400
76	Pitt St	1800.00		
76	Pitt St	1800.00		
123	Pitt St	1200.00	356,630	2400
123	Pitt St	1200.00		

Building Name	Building Name	Standby Rating (kVA)	Total Connection Cost (AUS$)	Total kVA
320	Pitt St			
320	Pitt St			
477	Pitt St	1300	258,415	1300
338-348	Pitt St	650.00		
QVB	PO Box Q292, QVB post office NSW 1230	500.00		
140	Sussex St	900.00	247,615	900
201	Sussex St			
201	Sussex St			
103-109	York St	725	218,415	1450
103-109	York St	725		

Table D3: LV Connection with Sequential Switching

Building Name	Building Name	Sub No.	Sub Name	Total Generation Capacity (kVA)	Cost of Connection (AUS$)
20	Bond St	4015	Exchange Cent. Pitt St No1	2000	382,000
20	Bond St	4016	Exchange Cent. Pitt St No2		
20	Bridge St	2535	Bridge Pitt		
20	Bridge St				
20	Bridge St				
50	Carrington St	7173	Wynyard Ln Margaret		Not Feasible
9	Castlereagh St	6237	Capita Castlereagh St	2250	373,000
9	Castlereagh St				
9	Castlereagh St				
60	Castlereagh St	5436	Elizabeth Martin Place		Not Feasible
60	Castlereagh St				
60	Castlereagh St				
159	Clarence St	3588	Red Cross Kent St	625	191,000
26-36	College St	6730	Hargrave Francis		
6-8	College St	1541	Museum	600	191,000
6	Dalley St	6324	Telecom Underwood		
6	Dalley St				
161	Elizabeth St	6935	Castlereagh & Market Sts	550	191,000

Building Name	Building Name	Sub No.	Sub Name	Total Generation Capacity (kVA)	Cost of Connection (AUS$)
1	Farrer Pl	7281	Phillip & Bridge Streets		
1	Farrer Pl	7282	Young Bent 30th Flr		
1	Farrer Pl	7283	Young Bent 51st Flr		
1	Farrer Pl				
1	Farrer Pl				
1	Farrer Pl				
1	Farrer Pl				
259	George St	5958	National Bk 16th Flr No1		
259	George St	6023	National Bk 16th Flr No2		
259	George St				
259	George St				
363	George St	3676	George Barrack 8th Flr		Not Feasible
363	George St				
363	George St				
363	George St				
400	George St	6524	George King No1		Not Feasible
400	George St	6572	George King No2		
580	George St	6198	Wilmot George		
580	George St	6279	Wilmot George 35th Flr		
580	George St				
264-278	George St	2299	Aust Sq Bond St West	3600	493,000
264-278	George St	2300	Aust Sq Tower 19th Flr		
264-278	George St	2301	Aust Sq Tower 35th Flr		
Fam. Crt	Goulburn St	6614	Castlereagh Goulburn		
66	Harrington St	4741	Archives Globe St		
66	Harrington St				

Building Name	Building Name	Sub No.	Sub Name	Total Generation Capacity (kVA)	Cost of Connection (AUS$)
85	Harrington St	4741	Archives Globe St		
1-7	Hay St	6872	Market City No1		
1-7	Hay St	6873	Market City No2		
309	Kent St	4190	Grosvenor Bldg Sussex	1375	191,000
347	Kent St	6985	Newtown Ln Sussex	1545	282,000
347	Kent St				
383	Kent St	7901	Sussex Market		Not Feasible
201-207	Kent St	6332	Kent Hickson No1		
201-207	Kent St	6333	Kent Hickson No2		
242-246	Kent St	6079	Telecom Clarence		Not Feasible
242-246	Kent St				
242-246	Kent St				
453-461	Kent St	836	Sony House Druitt St	450	191,000
135	King St	6405	Carringbush & King Sts		
135	King St				
26	Lee St	8006	Lee Regent		
20-24	Lee St	6260	Lee Little Regent		
1	Macquarie Pl	6302	Gateway Plaza Pitt No1		
1	Macquarie Pl	6303	Gateway Plaza Pitt No2		
1	Macquarie Pl				
1	Macquarie Pl				

Building Name	Building Name	Sub No.	Sub Name	Total Generation Capacity (kVA)	Cost of Connection (AUS$)
1	Macquarie Pl				
7-15	Macquarie St	446	Bennelong Macquarie No1		
7-15	Macquarie St	448	Bennelong Macquarie No2		
55	Market St	6689	Pitt Market No2	1600	282,000
55	Market St				
1	Market St	6729	Kent & Market Sth No1		
1	Market St	6814	Kent & Market Sth No2		
2	Market St	6631	Market Kent No1	2750	342,000
2	Market St	6632	Market Kent No2		
31	Market St	3245	St Martins Tower Clarence		
65-77	Market St	417	Market & Pitt Sts	2300	342,000
65-77	Market St	429	David Jones Castlereagh St		
1	Martin Pl	2957	Pitt & Martin No1		524,000
1	Martin Pl	3363	Pitt & Martin No2		
1	Martin Pl				
1	Martin Pl				
48	Martin Pl	5956	C'wealth Bk Roof 10th Flr	2000	191,000
48	Martin Pl				
38-46	Martin Pl	390	MLC Hosking Place	700	191,000
5-17	Martin Pl	7459	Commonwealth Rowe St		Not Feasible
1	O'Connell St	6839	Bent & Spring Sts		Not Feasible

Building Name	Building Name	Sub No.	Sub Name	Total Generation Capacity (kVA)	Cost of Connection (AUS$)
1	O'Connell St	6840	Bent Spring 6th Level		
1	O'Connell St				
2	Park St	4813	Park Pitt No1	4000	644,000
2	Park St	4814	Park Pitt 3rd Flr No1		
2	Park St	4815	Park Pitt 3rd Flr No2		
2	Park St	4816	Park Pitt 27th Flr		
88	Phillip St	4598	Phillip Lane No1		
88	Phillip St	4600	Phillip Lane No2		
88	Phillip St				
92-112	Phillip St	6865	Chifley Square No1		
92-112	Phillip St	6866	Chifley Square No2		
92-112	Phillip St	6867	Chifley Square 43rd Flr		
92-112	Phillip St	7947	Chifley Square 4th Flr		
92-112	Phillip St				
92-112	Phillip St				
76	Pitt St	2450	PMG Pitt St	1800	191,000
76	Pitt St	6848	PMG Pitt St No2		
76	Pitt St				
123	Pitt St	4224	Angel Ash No1	2400	342,000
123	Pitt St	4275	Angel Ash No2		
320	Pitt St	6220	Telecom Pitt Central		
320	Pitt St	3280?	PMG Castlereagh St		
477	Pitt St	6809	Pitt Barlow No1	1300	191,000
338-348	Pitt St	6912	Dungate Ln Castlereagh	650	191,000
QVB	PO Box Q292, QVB post office	6049	Queen Victoria Bldg	500	191,000

Building Name	Building Name	Sub No.	Sub Name	Total Generation Capacity (kVA)	Cost of Connection (AUS$)
	NSW 1230				
140	Sussex St	6776	Sussex Marks Ln	900	191,000
201	Sussex St	2633	Day Sussex No1		251,000
201	Sussex St	2737	Day Sussex No2		
103-109	York St	3973	National Mutual No1	1450	251,000
103-109	York St	3974	National Mutual No2		

Figure D1: Single Line Diagram of HV connection Design - Case 1A

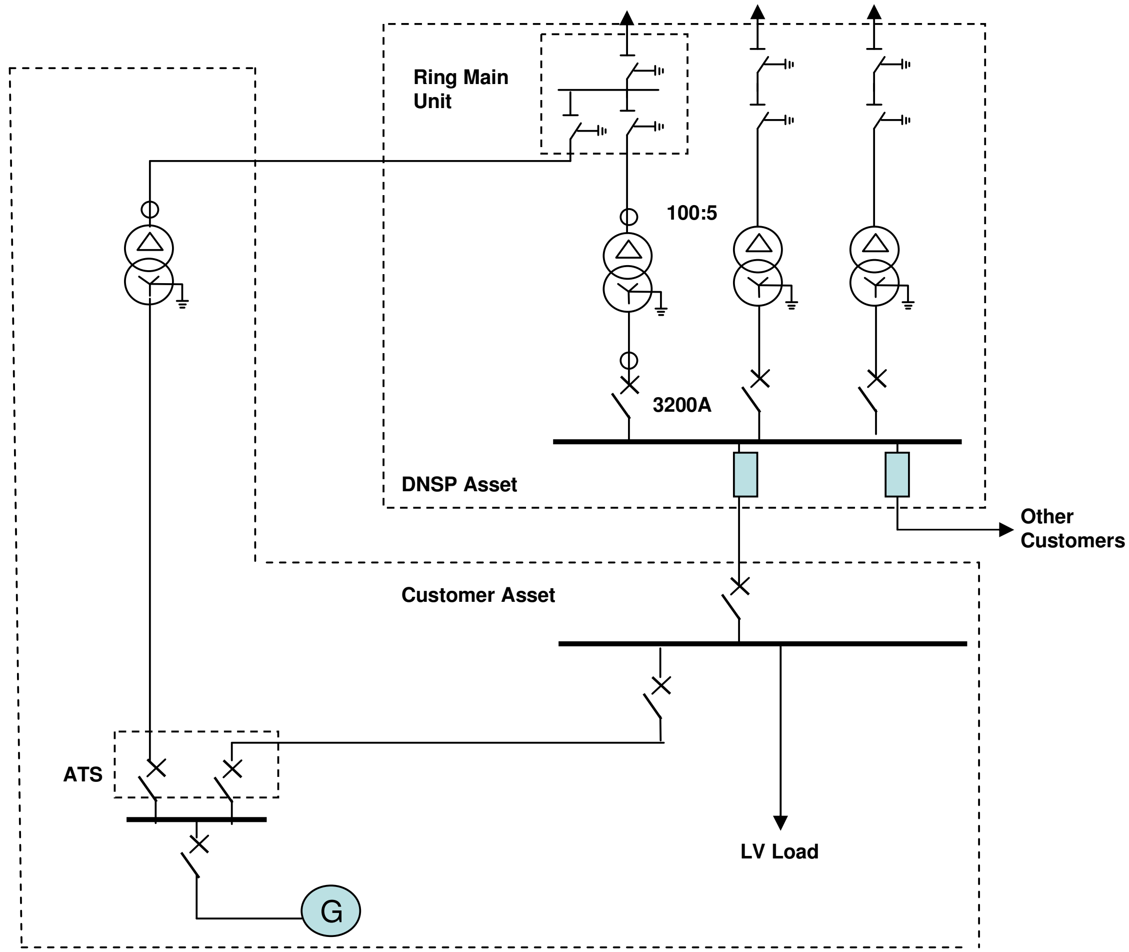


Figure D2: Single Line Diagram of HV connection Design - Case 1B

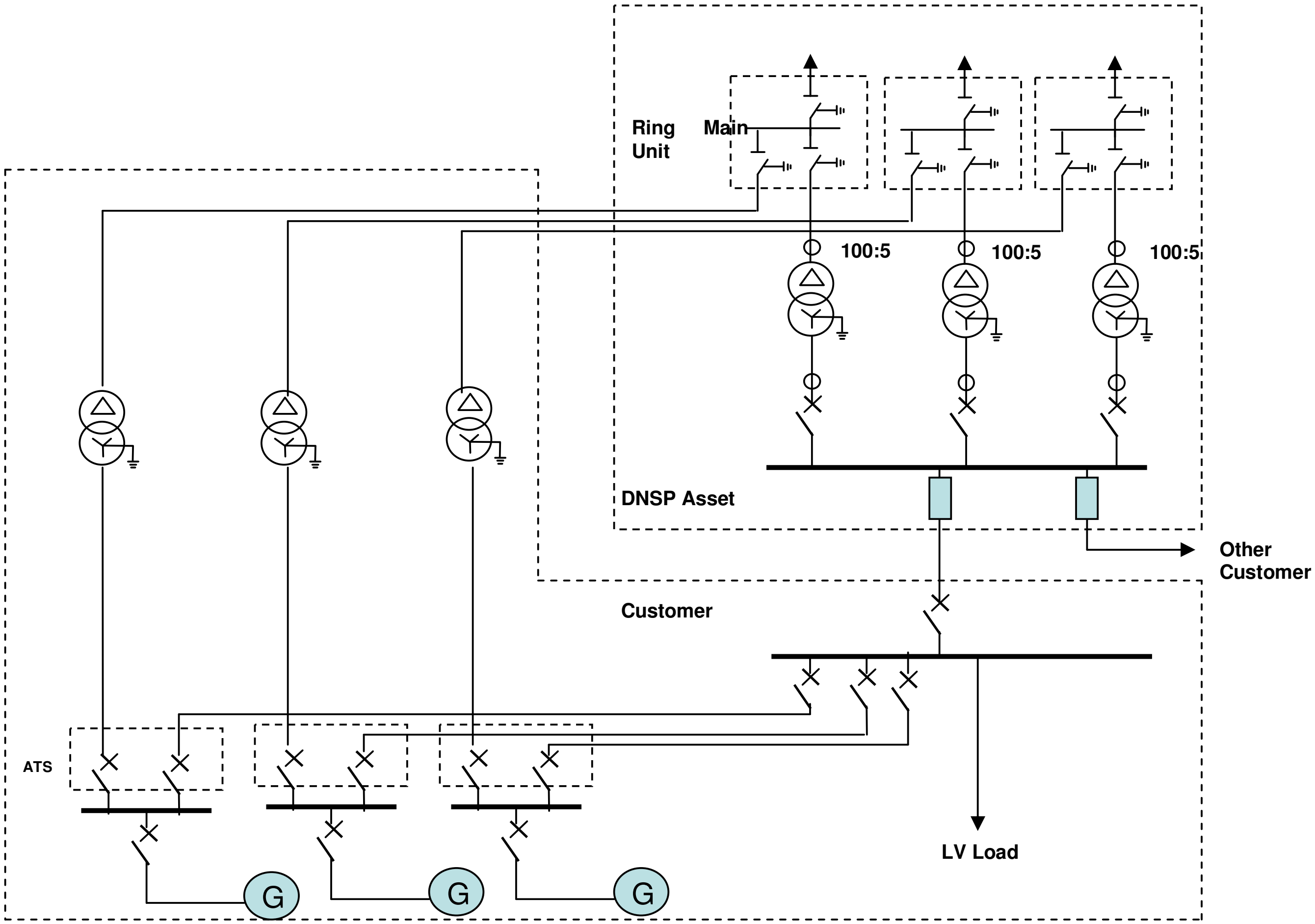


Figure D3: Single Line Diagram of HV connection Design - Case 2

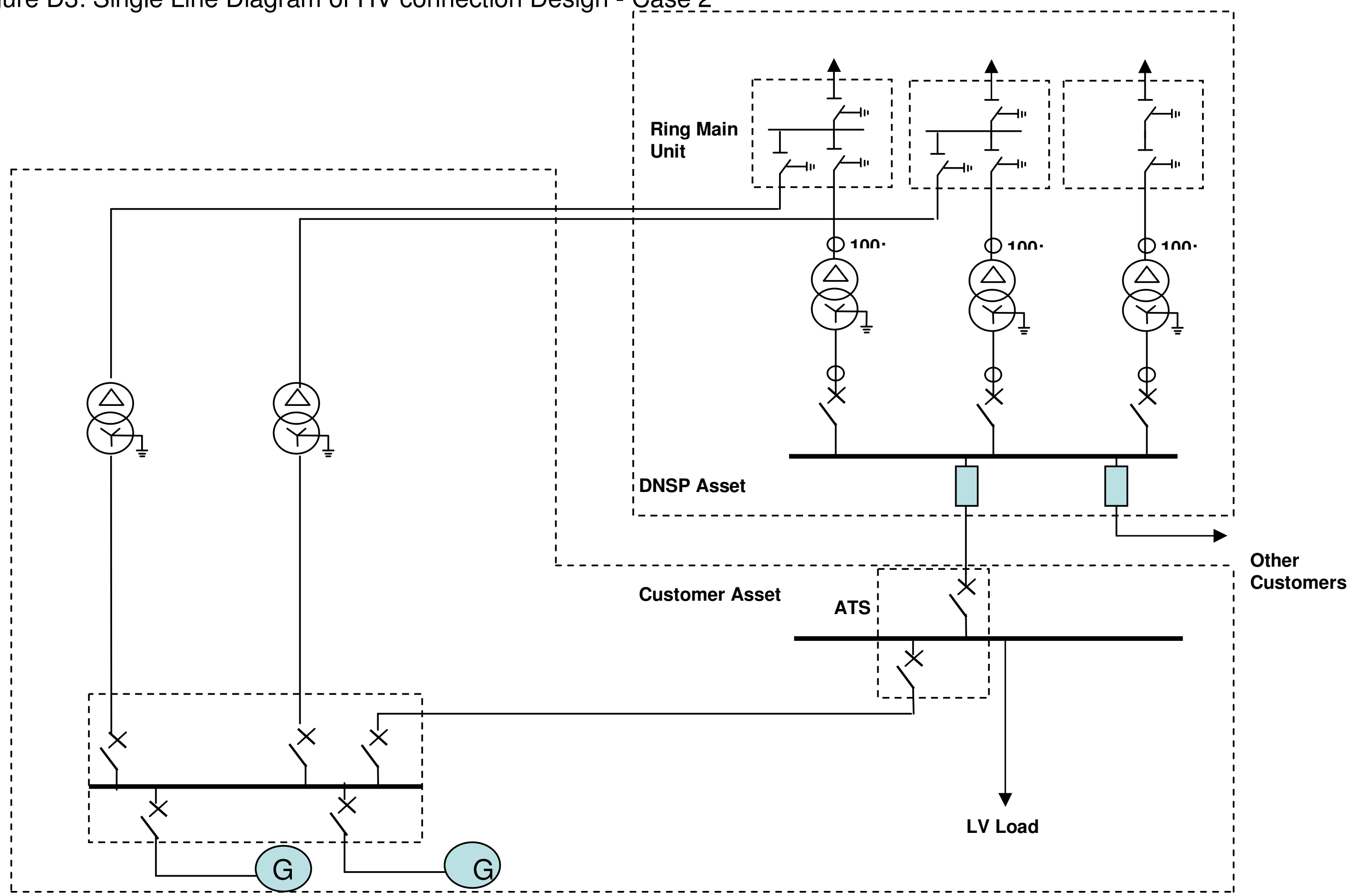
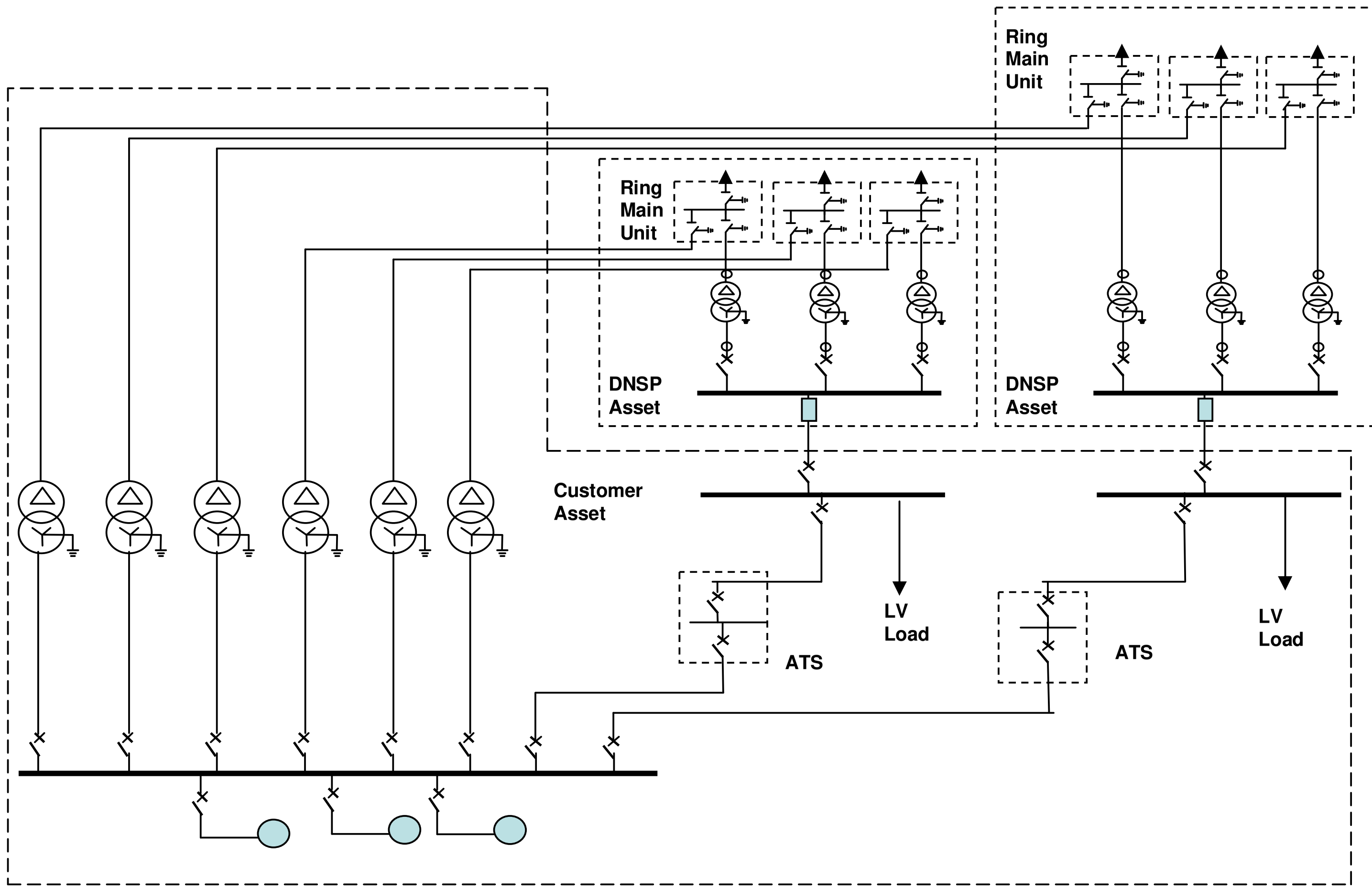


Figure D4: Single Line Diagram of HV connection Design - Case 3



8.5 Appendix E - Technical Details and Cost Estimate for the Integrated System for Generator Control

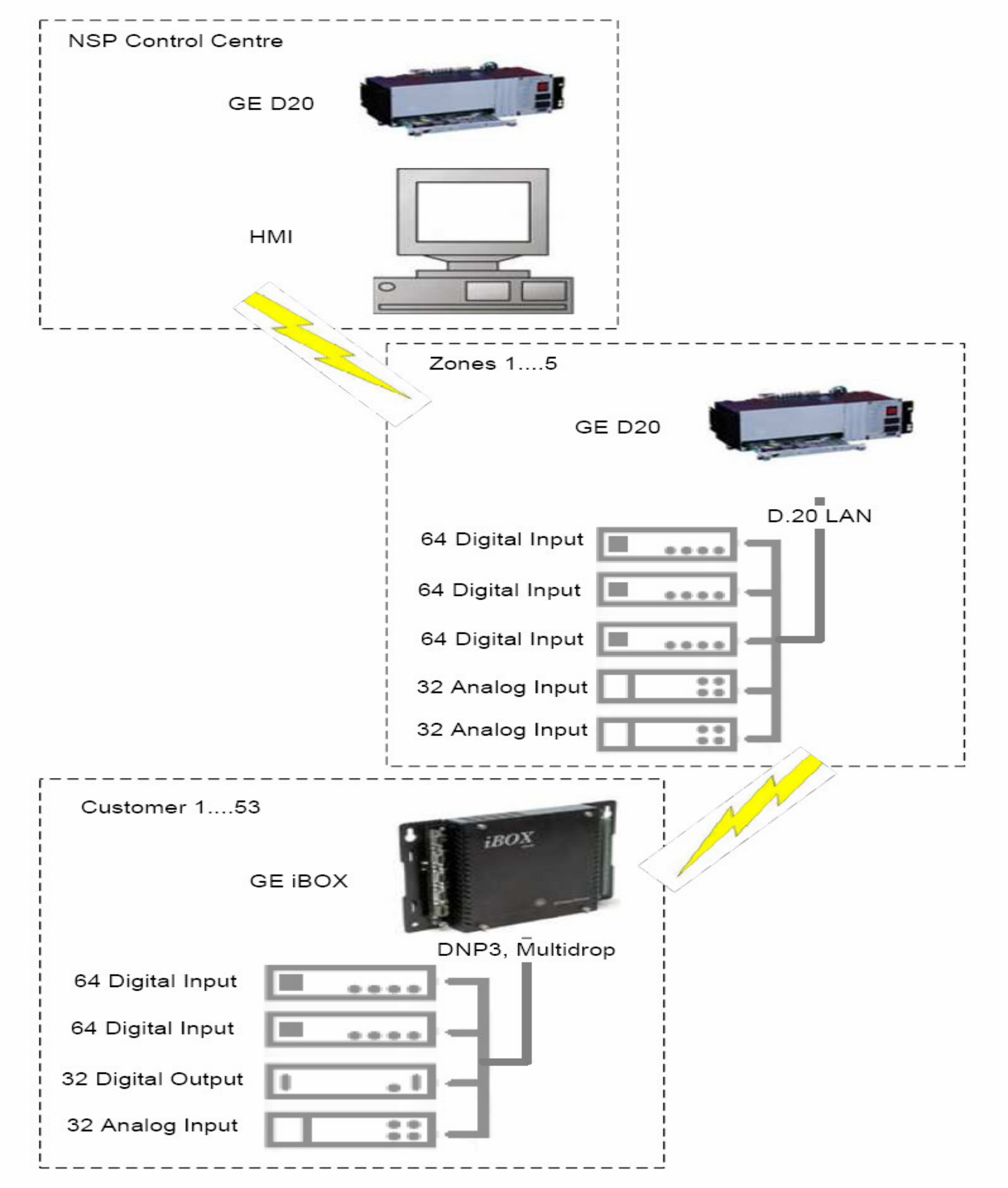


Figure E1: Generator Control Topology

eConnect Australia

SPIG Demand Management Standby Generation

Quotation

Alinta Asset Management

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Revision History

Revision	Date	By Whom	Description
1.0	02 Oct 2006	Steve Halikias	Initial Release

Prepared By

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Table of Contents

Introduction

Scope

This document is limited to the supply of unit pricing for complete engineering solutions relating to the SPIG Demand Management – Standby Generator system.

Copyright and References

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GE Hardware

Site Data Concentrator

We have chosen to offer the GE Energy Services D200 range for the Data Concentrator in this project at NSP Control Centre and at each of the five (5) zone substations. The GE Energy Services D20/D200 range of utility automation products provides a proven platform for ongoing systems development, whilst delivering outstanding reliability. These platforms deliver the processing capability to monitor and control thousands of substation I/O points.

The processing power is available to run sophisticated automation applications such as integrated LogicLinx™ programmable logic control (PLC), with uncompromising performance. All substation IED and device data is integrated, co-ordinated and made available to as many host systems or users as needed at the local, SCADA master or enterprise level.

GE Energy Services (previously GE Harris) was the first to invent and implement a distributed remote terminal unit for the electric utility industry. Their design has now evolved into the industry-leading platform for substation automation, the GE Energy Services D20/D200. Based upon an open-ended distributed architecture, and using a series of intelligent modules, the D20/D200 family will provide the Principal the flexibility to build a reliable, powerful and versatile system, capable of handling the monitoring, control, automation and communications requirements in its large substations.

The GE Energy Services D20ME board is the new generation processor for the D20 family. Using a Motorola® MC68030 processor, a substantial increase in performance is achieved over the D20M++ board. Other new features include FLASH memory, and an optional Ethernet daughter-board. As the board is compatible with existing D20 installations, (D20M++, VME and non-VME), it allows customers to easily upgrade simply by swapping processor.

The core of the GE Energy Services D20/200's modular design is the D20M main processor, which manages communications and data transfer between the hosts, local devices and remote intelligent substation and feeder devices. The open-ended architecture permits the addition of modules as, and where, you need them and provides parallel, distributed, real-time processing for greater configuration and application flexibility.

Maintenance is made easy with the D20/200's modular design. All I/O modules have front access and easy-to-reach field terminations, LED's and auxiliary hardware. To replace modules, simply unplug the logic unit and replace it with a spare working module, while the power remains on – termination panels remain in place and the wiring untouched. The D200 automatically downloads the appropriate database parameters to make the new module fully operational.

As a family of products, the D20/200 is intended to provide a long installed product life. Once in place, the Principal can easily install additional equipment, applications and features on its D20/200 systems without relinquishing the existing hardware and software. The D20 has been in field service with some customers for over a decade, evidencing its durability.

Site Controller

We have chosen to offer the GE Energy Services iBox unit as the Main Controller in this project at each customer site. The iBox is an economical substation controller, combining advanced functionality, multiple communication ports and local I/O in a compact package.

The iBox processes both digital inputs and digital outputs. It also provides serial digital data communications ports to facilitate communications with both a master station and local communications. The iBox is specifically designed for SCADA applications.

The iBox can function as:

- Programmable Logic Control (PLC)
- IED Gateway
- Data Concentrator
- Standalone Remote Terminal Unit (RTU)

GE Configuration Utilities

ConfigPro™

ConfigPro is a stand-alone, Microsoft Windows®-based application used to manage the hardware and software configuration for several types of devices and components supplied by GE Energy Services.

ConfigPro is a tool that helps you manage information associated with your remote terminal unit (RTU) equipment. It also manages information about various sites, sub-stations, and divisions of the utility you are working for. ConfigPro manages projects, devices and applications in a hierarchical fashion.

Logic Routines

LogicLinx™ is a soft logic automation tool, comprising of an Executor on the GE Energy Services platforms, and an IEC61131-3 Editor.

The application, which is common across the entire GE Energy Services range, allows users to easily create software automation applications that link components accurately and logically. The program utilises a Microsoft Windows® interface and is fully compliant with the IEC 61131-3 programming standard, using the IsaGraf package as its core.

Released onto the market in early 2000, several customers in the region have begun implementing applications with it. The product consists of a PC-based Editor and an Executor application resident on a GE Energy Services target platform. The Editor is Windows-based and compliant with IEC61131-3 standards. IEC61131-3 defines six standard soft-logic programming languages:

- Sequential Function Chart (SFC) - Describes operations of a sequential process using a simple graphical representation for the different steps of the process, and conditions that enable the change of active steps. It is considered to be the core of LogicLinx™, with other languages being used to define the steps within the flow chart.
- Flow Chart (FC) - A decision diagram composed of actions and tests programmed in Structured Text, Instruction List, or Ladder Diagram languages.
- Function Block Diagram (FBD) - A graphic representation of many different types of equations. Operators are represented by rectangular boxes with inputs on the left side of the box and outputs on the right. Custom function blocks may be created as well. Ladder Diagram expressions may be a part of a function block program.
- Ladder Diagram (LD) - Commonly referred to as "Quick LD", the LD language provides a graphic representation of Boolean expressions. Function Blocks can be inserted into LD programs.
- Structured Text (ST) - High-level structured language designed for expressing complex automation processes which cannot be easily expressed with graphic languages. Contains many expressions common to software programming languages (CASE, IF-THEN-ELSE, etc.). It is the default language for describing SFC steps.
- Instruction List (IL) - A low-level instruction language analogous to assembly code.

Other features include floating point operations such as trigonometric functions, program simulation, on-line program changes which do not interrupt the execution of the program, and built-in project management features such as archiving, development history, documentation, and password protection.

The Executor comes in two variations - "MACH" which supports only direct serial communications (i.e. serial port dedicated to LogicLinx™ Executor) and WESMAINT access (Executor may be accessed via any WESMAINT connection) and "WARP", which supports direct Ethernet TCP/IP communications.

The Editor comes in three variations - "Lite" which support 32 I/O points, "Basic" which supports up to 255 I/O points, and "Pro" which supports "unlimited" I/O (in excess of 30000 I/O points). The difference with each of these packages is controlled by a hardware dongle.

Aside from the compiler, LogicLinx™ has some powerful debugging tools. The most useful of these is the Simulator. Compiled projects can be simulated so that the flow of logic and expected outputs can be verified. A collection of I/O board simulation panels are generated by the simulator to create I/O inputs and outputs. The Debugger displays the application being run and the status of that application. Timing parameters are displayed, including the allowed cycle time, the current cycle time, and the maximum recorded cycle time allowing quick and easy program tuning.

The Spotlight feature of the application enables you to create icons and animations to represent actions in their project. LogicLinx™ also creates a Dynamic Data Exchange (DDE) server which can be used to dynamically display data in non-LogicLinx™ applications such as Microsoft Excel™.

One last on-line option is the ability to update project code while the project is active, without disrupting the flow of the project. Changes can be made to an existing project then uploaded to the target without halting execution of the application. The Executor can seamlessly switch from the previous version of the program to the new one without losing any internal data or state information.

On-line modification comes with a few restrictions. I/O variables cannot be added, renamed, or deleted. It is not possible to modify a SFC structure, nor to add, renumber, or remove a step, a transition, or a SFC program.

HMI

ClearSCADA™

For today's modern installations, ClearSCADA is introduced as a premium SCADA data collection, storage, retrieval and display product. Equally at home in a wide range of industrial and utility environments, ClearSCADA is the most feature-rich product on the market, maintaining the efficiency and ease-of-use that customers expect throughout the entire SCADA system life cycle

Based on industry-standard open interfaces and protocols, ClearSCADA efficiently interfaces with third-party software and hardware to provide seamless data exchange over a wide variety of communication links. With flexibility built into the core of the product, ClearSCADA systems scale easily from a single client/server to a large installation of dedicated servers and dispersed clients. Built-in system redundancy and data-backfilling features assure the highest degree of data reliability, without the need for code development.

Packed with intuitive features and powerful development, viewing, and reporting tools, ClearSCADA offers two client types that meet the needs of all system users. As a full function client, ClearSCADA ViewX provides highly developed operator-interface components including dynamic displays, alarm banner and event list, live and historic trending, and report generation. It is also the development environment with a wide range of productivity tools. ClearSCADA WebX is a thin client providing full operational functionality and process control over a secure Internet connection with your web browser. Using concurrent licensing, WebX clients allow your system to be viewed anywhere, anytime.

As a platform focused on efficiency, ClearSCADA employs object-based architecture to develop reusable templates containing all the operational characteristics essential for system deployment. At a low level these objects can represent single devices incorporating all associated tags, alarms and events, security and communication parameters. At a high level the objects represent entire sub-systems comprised of groups of devices. Libraries of industry-specific templates are easily built and then replicated throughout a system. When modification to a replicated sub-system is required, only a single change need be performed on the source template to effect change throughout the multiple instances of the template within the system

Budget Pricing

System design & installation costs for control centre and zone substations

DESCRIPTION **Generator Control Project System Design Costs (excluding per site costs)**	**COST [1,2,3,4] (ex. GST)**
Engineering & Configuration	**$94,300.00**
Supply of General System Design & Engineering. This includes but is not limited to the following activities – Development & application engineering and testing of control algorithm including logic integration plan for customer sites, Zone Substations and NSP Control Centre – Provide detailed design and functional specification of entire SCADA system – Application engineering & configuration works associated with the ClearSCADA HMI system – Internal testing and redundancy check. – New drawings for each Zone Substation & NSP Control Room	
Administration, Documentation & Testing	**$34,530.00**
Activities including but not limited to the following – Manage resource allocations and engineering resource – Procurement of all required materials – Arrange scheduling of SCADA outages with Principal for commissioning. – Test plans – Commissioning of Master Station HMI and each Zone Substation RTU and peripheral I/O as required	
Commissioning	**$33,170.00**
Commissioning of the Master Station Data Concentrator and HMI as well as Zone Substation RTUs and peripheral I/O into service, on site, NSW based on a single Systems Engineer on site. Commission hardware, software and applications on site. Provide on-site technical assistance for the following: – Installation of the firmware sets and initial power-up of the Controller & Peripheral on site. – Establishment of communications followed by point to point testing	

TOTAL DESIGN COST (EXCLUDING GST) [1,2,3,4]	**$162,000.00**

DESCRIPTION	COST [1,2,3,4] (ex. GST)
Generator Control Project System Hardware Costs (excluding per site costs)	

D200 Communications Server		**$50,433.90**
	6 x GE Energy Services D200 Communications Server including: – Westerm D20 VME Chassis Kit (500-0280) – Power Supply 90-260 V AC/DC (580-2007) – Wesdac D20ME (526-2005) – Wesdac D20EME 8MB Ethernet (526-2100) – Westerm D20M+ Panel Mount (517-0225) – Westerm D20EME 10base-T MIF (526-2110)	
Peripheral I/O		**$41,606.93**
	Supply GE Energy Services DNP I/O modules. 15 x GE Energy Services 64 Digital Input DNP Modules (24 – 60 VDC) 10 x GE Energy Services 32 DC Analog Input DNP Module (24 – 60 VDC)	
Hardware Application Licensing		**$6,048.00**
	Supply GE Energy Services Site Application licensing to suit the above hardware. – Ethernet Node Licenses (B052) – DNP3.0 DPA (B021) – DNP3.0 DCA (B023) – IEC870-5-103 (B080)	
Control Room Hardware		**$3,148.00**
	1 x IBM Desktop PC (HMI) Pentium 4, 2GB RAM, 250GB S-ATA HDD, CDRW, 19” TFT Flat Panel Monitor, Microsoft Windows XP Professional	
HMI Software		**$9,330.00**
	Supply of ClearSCADA Software Licensing – 1 x 5000 point Server / ViewX Client License with DNP3 Driver	
Inverter & Converter Supply’s		**$1,461.60**
	Supply of Inverter & converters suitable for the RTU cubicle containing 6 x Amtex DC / DC Converters	
RTU Cubicles		**$77,440.00**
	6 x Supply and installation of cabling and panels to house RTU & peripheral I/O	

TOTAL HARDWARE COSTS (EXCLUDING GST) [1,2,3,4]	**$189,468.43**

TOTAL PROJECT COSTS EXCLUDING SITES (EX GST) [1,2,3,4]	**$351,468.43**

System design & installation Costs for each customer site

Per Customer Site Costs	
Engineering & Configuration	**$10,650.00**
Supply of Design, engineering, configuration and testing Generator Controller. This includes but is not limited to the following activities – Development and testing of RTU configurations – Application engineering & configuration works associated with the Generator control algorithm – New drawings for each customer site	
Administration & Documentation	**$10,270.00**
Activities including but not limited to the following – Manage resource allocations and engineering resource – Procurement of all required materials – Arrange scheduling of SCADA outages with Principal for commissioning. – Test plans – Commissioning of each Generator Controller	
Commissioning	**$7,825.00**
Commissioning of the Generator Control system into service, on site, NSW based on a single Systems Engineer on site. Commission hardware, software and applications on site. Provide on-site technical assistance for the following: – Installation of the firmware sets and initial power-up of the Controller & Peripheral on site. – Establishment of communications at the customer site followed by point to point testing	
Hardware & Installation	**$19,583.60**
Supply of panel, cabling, installation services & GE Energy Services RTU Controller and peripheral I/O including: **RTU Controller:** 1 x GE Energy Services iBox Substation Controller (24, 48 or 110 VDC) **Peripheral I/O:** 2 x GE Energy Services 64 Digital Input DNP Modules (24 – 60 VDC) 1 x GE Energy Services 32 Control Output DNP Module (24 – 60 VDC) 1 x GE Energy Services 32 DC Analog Input DNP Module (24 – 60 VDC)	

TOTAL COST PER CUSTOMER SITE (EXCLUDING GST) [1,2,3,4]	**$48,328.60**

Notes

1 All pricing supplied in this quotation is in Australian Dollars, DDP (INCOTERMS 2003) Melbourne, VIC and exclusive of GST.

2 Indent for some equipment not ex-stock we would expect to be 8-10 weeks. This would be confirmed at placement of order.

3 All pricing is valid for 30 days from the date of quotation.

4 This proposal does **not** include;

- Communications infrastructure between all sites, zone substations and NSP Control Centre
- Time Synchronisation ability
- Enclosures (other then the RTU Cubicles)
- Control Room Desks
- UPS Supplies (DC converters included)
- Equipment Installation unless specifically stated
- Site Induction Expenses

General Terms and Conditions of Sale

1. Applicability The following terms and conditions form part of the quotation to which they are attached (the "Quote"). Unless otherwise provided in these terms, in the event of any conflict between the provisions hereof and of the Quote, the terms of the Quote shall prevail to the extent only of such conflict. The Quote, these terms and all other schedules, if any, attached to the Quote, are collectively referred to herein as the "Contract".

2. Purchase Price Unless otherwise stated in the Quote, prices quoted (the "Purchase Price") are in Australian Dollars and do not include any taxes, such as excise, sales, use, occupational, goods and services, or other taxes, statutory fees, costs of packaging and crating, transportation or insurance and, therefore, the Purchase Price is subject to additional charges equal to the amount paid by Alinta Asset Management to cover any such taxes and costs. Such additional charges shall be billed to the Customer's account, with supporting invoices, and form part of the Purchase Price. Customer shall pay the full price of goods and services by way of an Irrevocable Documentary Letter of Credit in favour of Alinta Asset Management for one hundred percent (100%) of the Purchase Order Value (or specified part thereof) upon presentation of shipping documents and beneficiary's drafts at Sight.

3. Title and Risk All risk to the system, comprised of Alinta Asset Management products (the "Products"), software and firmware integrated with products, software and firmware manufactured or licensed by other parties (the "System"), as more particularly described in the Quote, shall pass to the Customer upon delivery by Alinta Asset Management, to the F.O.B. point, which unless otherwise specified in the Quote shall be Alinta Asset Management's loading dock at the place of manufacture of the System. Upon receipt by Alinta Asset Management of payment of the Purchase Price in full, and not before, title to the System shall pass from Alinta Asset Management to the Customer.

4. Non-Exclusive License Only to the extent necessary to use the Products (items manufactured by Alinta Asset Management) purchased pursuant to this Contract, for the purposes for which such Products are manufactured, Alinta Asset Management grants the Customer a non-exclusive right to use software, firmware, programs and any other technology necessary to operate and use the Products, in conjunction with the Systems delivered to the Customer by Alinta Asset Management. This right shall be non-assignable and non-transferrable by the Customer (except for sub-licenses to any subsequent purchaser of the Products or System) and shall apply and be irrevocable with respect to each unit of Product or equipment purchased under this Contract, and paid for in full by the Customer.

For products, equipment and software other than the Products the license provisions of the third party licensors applicable to individual portions of software, firmware and any other technology necessary shall apply

5. Proprietary and Confidential Information All proprietary and confidential proprietary information provided by Alinta Asset Management shall be treated confidentially and applied only as intended in connection with specific purchase orders. Such information shall be restricted to those persons who have a need to know and who have been advised of its proprietary nature. The Customer will ensure that it enters into agreements with employees, consultants, agents, shareholders and any others who have or may obtain access to the information, to maintain said information in confidence. These provisions shall survive the termination of this Contract.

6. Delivery The Customer agrees that, notwithstanding the delivery date specified in the Quote, Alinta Asset Management does not guarantee the delivery date and Alinta Asset Management shall not be liable for any damages or penalty for delay in delivery or for failure to give notice of delay when such delay is due to Force Majeure (as defined in these terms), delays in transportation, delay in delivery by suppliers of components to Alinta Asset Management or any other causes beyond the reasonable control of Alinta Asset Management The scheduled delivery date shall be extended by a period of time equal to the time lost because of any such delay.

7. Warranty for System Manufactured by Alinta Asset Management and Limit of Liability

This warranty is issued by Alinta Asset Management only for the System supplied by Alinta Asset Management. Any equipment items or software or firmware of System manufactured or licensed by persons other than Alinta Asset Management carry only the warranty provided by the manufacturers or licensors thereof and Alinta Asset Management gives no warranty on behalf of the manufacturers or licensors.

Alinta Asset Management warrants to the Customer that the System, other than equipment items or software or firmware manufactured or licensed by persons other than Alinta Asset Management, will be free from defects in material and workmanship for a period of 12 months from the date of delivery Ex Works. Subject to the terms and conditions of this warranty, upon the prompt written notification by the Customer of a defect in material or workmanship, and upon a determination by Alinta Asset Management that such System contains defective materials or workmanship, Alinta Asset Management will repair or replace such defective System components at Alinta Asset Management's cost or will authorise the Customer to repair or replace such System components on mutually agreeable terms. Any such System components requiring repair will be repaired or replaced and shipped to the Customer's premises, prepaid and at the cost of Alinta Asset Management, within 20 business days from receipt of the defective System components at the Alinta Asset Management repair facility. The cost of de-installation and re-installation shall be borne by the Customer and this warranty does not include any such costs.

This warranty is in effect provided that:

(a) the System is used and serviced in accordance with instructions provided by Alinta Asset Management;
(b) the System has been properly stored and installed in accordance with the specifications of Alinta Asset Management;
(c) the System has not been altered or repaired without prior written authorisation from Alinta Asset Management; and
(d) the System has not been used in conjunction with defective or inferior products which could result in damage to the System.

Alinta Asset Management represents and warrants that software and firmware licensed by it and its integration of the System is free from functional deficiencies. If any functional deficiencies are discovered and are reported to Alinta Asset Management within the warranty period, Alinta Asset Management agrees to use due diligence to correct such deficiencies within 30 days after receipt of such notification. Upon receiving such notice, Alinta Asset Management may lend telephone support or patches. If the reported deficiencies cannot be eliminated within 30 days, the Customer may request, and Alinta Asset Management shall then furnish, monthly status reports to the Customer regarding the progress of Alinta Asset Management's efforts to correct such functional deficiencies.

This warranty for System is in lieu of all or any other warranties of Alinta Asset Management, express or implied, by operation of law or otherwise, of the System or services furnished hereunder, including merchantability or fitness for a particular or intended purpose, which are disclaimed and expressly waived, and this warranty shall extend only to the Customer and may not be assigned, altered or extended in any way except by an instrument in writing signed by Alinta Asset Management. Alinta Asset Management does not authorise any person to assume, on its behalf, any other obligation or liability.

IN NO EVENT SHALL ALINTA ASSET MANAGEMENT BE LIABLE FOR ANY ACCIDENTAL, INDIRECT, SPECIAL OR CONSEQUENTIAL DAMAGES IN CONNECTION WITH OR ARISING OUT OF THE CONTRACT OR THE SALE, USE OR REPAIR OF THE SYSTEM. ALINTA ASSET MANAGEMENT SHALL NOT BE LIABLE FOR ANY LOSS OF USE, REVENUE OR PROFIT NOR FOR ANY CLAIM, DEMAND OR ACTION AGAINST THE CUSTOMER BY ANY THIRD PARTY. THE CUSTOMER'S SOLE AND EXCLUSIVE REMEDY FOR LIABILITY OF ANY KIND, INCLUDING NEGLIGENCE WITH RESPECT TO

THE System AND SERVICES FURNISHED HEREUNDER, IF ANY, SHALL BE LIMITED TO THE REMEDIES PROVIDED IN THIS SECTION 7 AND SECTION 8 HEREOF.

ALINTA ASSET MANAGEMENT ACCEPTS NO LIABILITY FOR ANY ITEMS OF EQUIPMENT, SOFTWARE OR FIRMWARE INCLUDED IN THE SYSTEM BUT NOT MANUFACTURED OR LICENSED BY ALINTA ASSET MANAGEMENT

NOTWITHSTANDING ANYTHING IN THE CONTRACT BETWEEN ALINTA ASSET MANAGEMENT AND THE CUSTOMER, ALINTA ASSET MANAGEMENT SHALL AT ALL TIMES, AND FOR ALL PURPOSES, BE LIMITED TO NO MORE THAN THE PURCHASE PRICE OF THE SYSTEM PURCHASED BY THE CUSTOMER PURSUANT TO THE CONTRACT. SUCH AMOUNT IS CONSIDERED BY THE PARTIES HERETO TO BE A GENUINE PRE-ESTIMATE OF THE CUSTOMER'S LIQUIDATED DAMAGES.

8. Repair and Replacement All expenses for the repair or replacement of non-defective items or items caused to be defective because of unauthorised modifications or changes to software or hardware or due to causes external to the System, shall be charged to the Customer's account.

9. Default and Remedies In the event that the Purchase Price has not been paid in full and:

(a) the Customer, upon ten days prior written notice, has failed to perform any obligation to be performed by the Customer under the Contract; or

(b) a petition in bankruptcy has been filed by or against the Customer or the Customer has made an assignment for the benefit of creditors or a receiver has been appointed or applied for by the Customer or the Customer has become insolvent, the Customer shall be and be deemed to be in default and the Purchase Price shall immediately become due and payable in full. Alinta Asset Management may elect, without prejudice to any other remedies available to it, to terminate the Contract. All payments received by Alinta Asset Management as part of the Purchase Price shall be forfeited to Alinta Asset Management as partial liquidated damages. In addition, and whether or not Alinta Asset Management terminates the Contract, Alinta Asset Management shall be entitled to seize or repossess the System and subsequently sell such System to mitigate its damages. The Customer acknowledges that such seizure and sale shall not in any way prejudice Alinta Asset Management's rights to take action against the Customer for any deficiency or damages suffered due to such default.

10. Consent for Credit Checks and Searches The Customer hereby authorises Alinta Asset Management to conduct all credit checks and searches regarding the Customer and its financial and other business affairs at the discretion of Alinta Asset Management, and the Customer shall promptly provide all necessary written authorisations for such credit checks and searches as requested from time to time by Alinta Asset Management.

11. Force Majeure Neither party shall be liable for the performance of its obligations under the Contract if such performance is prevented by an event of Force Majeure. Force Majeure shall mean any one or more of the following events that prevent performance of either party's obligations hereunder:

(a) acts of God or actions of the elements, including but not limited to, perils of the sea, fire, explosions, earthquakes, floods and epidemics;

(b) wars, revolutions, insurrections, riots and disturbances, blockades and other unlawful acts against public order or authority;

(c) strikes, lockouts, labour disturbances;

(d) directions, orders or legislation by government or any government, governmental authority or agency having or purporting to have jurisdiction, jurisdictional disputes, injunctions and orders of courts;

(e) shortages of suitable parts, materials, labour or transportation or other causes beyond Alinta Asset Management's control which affect production, transportation or delivery of the System or provision of the services contracted for hereunder, if any; or

(f) any other event (whether or not of the kind enumerated in this Section) excluding financial distress, that is not in the reasonable control of the party claiming Force Majeure.

The party to the Contract claiming the existence of any event of Force Majeure shall promptly notify the other party to the Contract of the claim and shall do all things reasonably possible to surmount the event and resume performance hereunder as soon as the cause is removed. In the event the Force Majeure continues for a period of 60 days, either party shall have the option to terminate the Contract.

12. Severability Any provision of the Contract which is illegal or unenforceable in whole or in part shall be severable from the Contract and the remaining provisions of the Contract shall remain in force and be binding upon the parties.

13. Joint and Several In the event there is more than one Customer, their liability and obligations under the Contract are joint and several.

14. Assignability The Customer shall not assign or otherwise transfer or encumber its rights or obligations under the Contract, except with the prior written consent of Alinta Asset Management any prohibited assignment, transfer or encumbrance shall be null and void.

15. Enurement Except where provided otherwise, the Contract shall ensure to the benefit of and be binding upon the parties hereto and their respective successors and permitted assigns as fully and effectively as if the same were parties hereto.

16. Governing Law The Contract shall be governed by the laws of New Zealand, unless the parties have otherwise agreed in writing. The parties hereto hereby attorn to the jurisdiction of the courts of New Zealand.

17. Waiver No waiver of any provision of the Contract shall serve as a waiver of any other provision of the Contract and Alinta Asset Management shall not have waived or be deemed to have waived any provision of the Contract unless such waiver is in writing and executed by Alinta Asset Management

18. Entire Agreement The Contract (including the Schedules attached thereto) contains the entire agreement between the Customer and Alinta Asset Management with respect to the subject matter as of its date and supersedes all prior negotiations, representations and proposals, written and verbal relating to the subject matter.