University of Southern Queensland

Facility of Engineering and Surveying

The energy storage potential of a hybrid renewable generation grid connected to a pumped hydro-generation plant for effective connection into the energy market, off peak switchable developing load demand market and act as ancillary regional voltage support and bulk water supply.

A dissertation submitted by

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Bachelor of Power Systems Engineering

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Abstract

The primary objective of this study is to determine if a pumped hydro energy storage facility located near Toowoomba's Cressbrook dam is currently an economically viable option for South East Queensland. The intended purpose of this system is to ultimately act as fast acting ancillary grid service to help alleviate South East Queensland's ever increasing fast demand fluctuations as seen by the grid operators. These fluctuations are primarily due to the current and continually increasing installed domestic and utility scale intermittent Photovoltaic (PV) generation. This situation is becoming increasingly costly and problematic as grid security is becoming harder to maintain as a result. In trying to maintain an acceptable supply standard, this forces the energy markets power spot price to reach exceedingly high levels more frequently in addition to imposing increase stress on the grids infrastructure when compensating.

It was determined that the selected site north of Toowoomba is more than sufficient to cater for a hydro facility. There is adequate space, water resources, and elevation between catchments along with the area having no environmentally or culturally sensitive areas. There was no restriction upon the site from initial investigations being a prime location for a PHES project.

To carry out the economic viability testing the HOMER simulation package was used. From initial testing the proposed system was deemed to be currently too expensive with the return from sales simply being insufficient within the current energy market.

As a result future viability tests were conducted with a proposed large scale feed in tariff with the main difference in tariff structure being that it did not impose a demand cost. This greatly increased the economic viability of the project and made the possibility of such infrastructure much more likely, with the system now returning a profit on many of the variants. Furthermore an additional renewable generation element as investigated to aid pumping, comprising of possibly both a PV and wind farm proved to be a very beneficial option. Depending on yearly load and model variation the size of each renewable component changed but proved to be valuable to the system, with also improving the systems environmental footprint which was a major factor.

It was concluded that the proposed PHES system would be a very effective compensating tool to SEQ's demand fluctuations and is viable in the proposed location. However it is currently too expensive under contemporary tariff structures and it is advised that a large scale feed in tariff for such infrastructure is put into effect as this would greatly aid the viability of such systems. Additionally the proposed system will continue to become more viable as time progresses due to current trends within the energy and renewables market, in addition to being increasingly necessary if the demand fluctuations continue to increase in regularity and severity.

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I certify that the ideas, designs and experimental work, results, analyses and conclusions set out in this dissertation are entirely my own effort, except where otherwise indicated and acknowledged.

I further certify that the work is original and has not been previously submitted for assessment in any other course or institution, except where specifically stated.

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30/OCT/2014

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Nomenclature and Acronyms (Abbreviations)

Term	Acronym	Term	Acronym
Photovoltaic	PV	Supervisory Control and Data Acquisition	SCADA
South East Queensland	SEQ	Extreme High Voltage	EHV
Pumped Hydro Energy Storage	PHES	Direct Current	DC
Power Factor	PF	Australian Energy Market Operator	AEMO
National Energy Market	NEM	Automatic Voltage Regulating	AVR
High Voltage	HV	Low Voltage	LV
Minimum Reserve Level	MRL	Energy Adequacy Assessment Projection	EAAP
Frequency Control Ancillary Services	FCAS	Network Control Ancillary Services	NCAS
System Restart Ancillary Services	SRAS	Large-scale Renewable Energy Target	LRET
Electrical Energy Storage	EES	Department of Environment and Resource Management	DERM
Vanadium redox battery	VRB	Levelised Cost of Electricity	LCOE
Large-scale Generation Certificates	LGC’s	Static Compensator	STATCOM
Volt-amperes	VAR’s	Net Present Value	NPV

Chapter 1 – Introduction

1.1: Study Outline

The main premise of this study is based upon a current problem affecting South East Queensland (SEQ) with regards to the current installed domestic and utility scale Photovoltaic (PV) generation. Queensland's installed PV is subject to Australia's' ever-dynamic weather systems, resulting in unpredictable and fast fluctuations in overall grid demand. This intermittent and unpredictable PV generation is already having serious implications upon the grid, of which making the prediction of the afternoon shoulder demand an increasingly difficult task. This effectively results in the demand predications particularly around the afternoon shoulder period, are becoming increasingly more erroneous on more occasions.

Consequently this leads to the spot price of power for the region to reach very high levels as energy has to be imported from external ancillary services such as the snowy mountain hydro scheme. These ancillary services are needed to compensate for the shortfall of power whilst the necessary black coal power margin is ramped up to take the rising afternoon consumer load leading into the evening peak in South-east Queensland.

Having to forecast for demand with so many fluctuating and intermittent factors that the energy network is comprised of, let alone with now the large installed PV capacity is difficult. PV is having such an effect when trying to forecast accurately, that AEMO[1] now publishes a quarterly Energy Adequacy Assessment Projection (EAAP) document in light of this.

This subsequently forces the Queensland electricity grid to take corrective measures to maintain grid stability. Maintaining this grid stability at low voltage (LV) levels is relativity easy through the use of Automatic voltage regulating equipment (AVR) and Load Drop Compensating Equipment (LDC), which when on load tap change the necessary transformers in compensation of the load variations. However at high voltage (HV) stability becomes more complex, mainly due to the HV system being interconnected system unlike the LV systems being a radial configuration. Mismatches in active and reactive power generated and demanded can give arise to frequency fluctuations and voltage fluctuations respectively[2] being an area of concern.

Therefore compensation measures need to be taken to prevent these occurrences from happening in the flux period for approximately an hour or more where the bulk generators are increasing their output in response. Such methods include utilising the National Electricity Market (NEM)[3] to import power from other regional market jurisdictions as stated before; however this is an expensive endeavor. Other contingency measures include load shedding or the utilization of spinning reserve resources, where the minimum reserve level (MRL) in Australia for each region is calculated by 10% probability of exceedence of the scheduled regional maximum

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[1] (AEMO, 2011c)
[2] (G. Ramakrishnan, 2013)
[3] (AEMO, 2014a)

demand conditions[4]. This reserve capacity however is not used in this manner so it is not a viable option. Therefore with all conventional means considered the solution lies simply in the addition of suitable generation capacity to stop such problems within the electricity grid and to maintain SEQ's power security.

AMEO within their Power System Adequacy Report that 'no more than 0.002% of demand in any region should be interrupted due to a lack of supply'(AEMO, 2011c). This consequently results in Queensland requiring more than 900 megawatts of highly versatile reserve capacity, a market of which a pumped hydro storage system would comfortably fit into.

Therefore the fundamental outline of this study is to investigate SEQ's PV fluctuation problem, and in turn investigate if there are other cost effective and more sustainable solutions available. A possible solution to this problem potentially lies within the concept of a Pumped Hydro Energy Storage (PHES) scheme, with a sustainable PV or wind energy element potentially incorporated to provide additional renewable energy that then is able to be stored. This energy can then be time shifted to support the often unpredictable afternoon shoulder load rise in addition to the fluctuating PV system, as well as be potentially available to help hem the evening peak demand.

Therefore the key objectives in this project are to investigate and evaluate if such a PHES scheme would benefit SEQ and its power grid by further increasing energy security in face of the changing energy climate. This project is also to assess if such a project could become a necessary piece of Queensland based infrastructure that would also be sustainable and profitable.

1.2: Introduction

This problem is challenging due to the rapidly changing energy output of SEQ's PV system coupled with the slow in comparison coal fired power station units reaction times, of which are measured generally in 30 minute intervals. Therefore to maintain grid stability, power importation reliance is on other expensive Eastern Australian bulk energy suppliers via Queensland's East-link connection to compensate.

Furthermore electricity within the network cannot simply be switched and moved easily within the system. The start, prediction and tracking of the afternoon shoulder rise to evening peak load change needs to be balanced. Failing to do so requires reliance on other interstate supply surpluses, or can in fact mean energy from other hydro systems in New South Wales has to be imported. Such systems being the Kosciusko Snowy Mountains Scheme or even possibly Tasmania have to be then ramped up in provision for Queensland's short time load changes. This ultimately means additional expense to Queensland customers. Thus energy storage is a necessary infrastructure development if solar or other sustainable energy sources penetration is to continue to grow to provide power for such purposes, with potential as well for future export from Queensland.

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[4] (AEMO, 2011c)

On the other hand if the demand cannot be satisfied by imported energy from the NEM, then load shedding needs to be carried out of which then can cause possible logistical problems. This is done to try and balance available generation supplies from both within Queensland and other external interstate sources on the energy network, along with load switching upon the grid to move power to the necessary locations. This can be carried out with the addition with Queensland's spinning reserve capacity to maintain grid security; however this capacity is generally only used to compensate for generation and transmission outages[5] and not for power fluctuations.

This is the justification for the study, to find if a PHES system, with or without a PV and wind sustainable energy component maybe an economical future infra-structure development for SEQ. It would greatly aid the stability of SEQ's electricity network in a variety of ways whilst also aiming at being a more cost effective resolution, reducing the cost of power for not only the producers but also for the consumers.

Furthermore in future it may also allow Queensland's high availability of PV energy generation sites to become a net exporter of energy, as there would a way to store the power. This also could be a means of developing a future energy EHV DC link into the South-East Asia energy market via Singapore as the demand here is ever rising.

1.3: The Problem

The problem stems directly off the significant and largely unpredictable PV generation capacity SEQ integrates into the transmission grid. This form of renewable generation is subject to many external environmental factors constantly altering output, of which having major implications for the quality and cost of power in SEQ. Both commercial and domestic PV arrays play apart here as their combined outputs throughout the day reduces the total demand from the bulk electricity suppliers, but this is not the problem. The main problem lies within the afternoon shoulder load rise period where subsequently the total PV output reduces at the same time demand starts to increase. This occurs due to the solar exposure drops as the sun goes down approximately at the same time. Therefore the power companies have to increase their output to compensate for not only the shoulder demand rise, but additionally for the PV generation output reduction also. Compensation for these changes is difficult to achieve as both changes are unpredictable and dynamic in nature changing on a daily basis[6]. This anomaly is evident in Figure 1 showing the comparison between Queensland's energy demand with and without solar.

5 (E. S. Association, 2014)

6 (Parkinson, 2012)

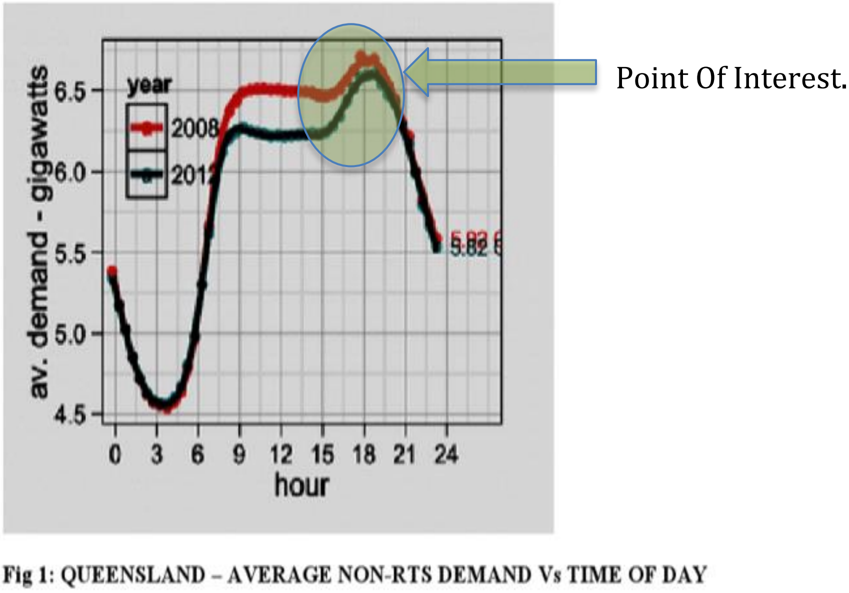

Figure 1: Queensland – Average non rooftop solar demand vs. time of day (RenewEconomy, 2012)

When AEMO effectively tries to predict the often unpredictable afternoon shoulder load rise, having to take the large PV component into consideration also makes controlling the system ever more difficult. With such possible large variations in both power production and consumption within the network, keeping the network within tight tolerances does not come cheap to energy producers or consumers.

The integration of this unknown intermittent generation has been one of the main struggles for some renewable technologies[7]. The main technologies subject to this are wind and solar renewable schemes. These schemes form the bulk of world renewables generation of which the total global PV generation was approximately 67GW by the end of 2011[8], while total global wind generation reached approximately 318.5GW by the end of 2013[9]. Furthermore according to Global Trends in Renewable Energy Investment 2014[10] states that 44 percent of all world generation capacity installed in 2013 was renewable power. This statistic depicts the large renewable power movement across the world, and it brings with it a necessity from more effective storage options to negate the most prevalent problems associated with it.

1.4: Research Objectives

To ascertain if installing a pumped hydro energy storage system would be effective in helping to mitigate the effects of the growing photovoltaic generation in South East Queensland. The main area on concern is the afternoon shoulder period of which grid security is most at risk due to the large installed utility and domestic

7 (Luoma, 2009)
8 (IEA, 2014)
9 (Shanghai/Bonn, 8 April 2014)
10 (Finance, 2014)

solar generation, the unknown possibility of weather effects and the period in the demand cycle when the variations are most likely to occur.

To verify if the intended site is able to be developed, being that there is no cultural or environmentally sensitive areas within the location of the PHES or renewable systems.

To confirm that the PHES system would not only aid in maintaining grid security but also be an economically viable and sustainable piece of infrastructure for Queensland.

To ascertain if the addition of renewable technology into the system to aid in pumping would be a beneficial endeavor, and to measure what renewable fraction of total load would optimal.

1.5: Conclusions

In conclusion the intended location of the proposed system proved to be more then appropriate, having no pre-existing issues associated with it. The PHES system however from initial testing yielded results even under optimal conditions, that make it simply unviable economically. Such a system requires a large amount of initial capital to construct, along with the operating equipment being expensive also. This is largely in regards to the pumping and generating equipment of the plant being more expensive as it is not a conventional system. Additionally the renewable elements of the project proved to be very beneficial with many of the optimal models containing a renewable fraction greater than 50%. This result was very pleasing as a large renewable fraction was envisioned for this project to reduce its environmental footprint.

However future viability testing was conducted and it was concluded as time progresses this system will not only become more economically viable, but increasingly necessary to maintain energy security. This is due to current energy market trends where the price of power is steadily increasing, along with the gradual decrease of renewable technology costs as they become more efficient and effective. Furthermore it was also proposed that if a special tariff was to be created specifically for such beneficial ancillary services, this would greatly reduce costs and increase feasibility. If such a scheme was to be put into effect this system then could be implemented much sooner.

Chapter 2 - Literature Review

2.1: Introduction

As renewable energy is becoming more prevalent within society with various technologies being advanced and researched, some of the old associated problems still plague the industry. These problems arise primarily from the intermittency of which most of the main renewable systems rely upon. Having to depend upon mostly unpredictable chaotic events such as the weather is not adequate for when supplying to such a complex power grid.

2.2: Pumped Hydro Energy Storage

Hydro electricity is one of the most prevalent forms of renewable energy generation in the world today, producing approximately 3 288TWh being around 16% of world energy production in 2008[11]. Pumped Hydro as a part of this accounted for 127GW of the total worldwide capacity in 2009 and is continuing to grow as PHES is currently the most established and economical large scale from of energy storage technology. This technology effectively allows for bulk energy suppliers to use their excess energy output in times of fluctuating load to store the power so that it can be time shifted for future peak periods. Essentially PHES is a battery with the electricity being stored not conventionally as a potential difference, but as a head of water.

Furthermore contemporary bulk energy generators cannot effectively or rapidly change their outputs with respect how fast the demand can fluctuate, and therefore a need for such large scale ancillary support is required of which PHES can provide effectively also[12]. The previously stored energy which otherwise would have been 'wasted' now could be stored and used to support the bulk produces in times of need. This would help maintain grid security within the system, or even just be used in a time of peak demand and sold for a much higher price for profit.

The one way a PHES system differs from a conventional hydropower plant is that in a PHES system there is a pumping element to cycle the water back up to its original location before being used, so that it may be used again. This allows the same water to be used for generating many times, a trait being of great benefit to a continent such as Australia that suffers heavily from drought so often.

2.2.1: Reservoirs of Interest

2.2.1.1: Perseverance Dam

Perseverance Dam	
Maximum Height	56 m Approx.
Crest Length	207.7 m
Dam Crest level	EL 452.6 m

[11] (I. E. Agency, 2010)
[12] (Yang)

Storage capacity at crest	46 000 ML
Maximum capacity level	EL 446 m
Surface area when full	216 ha
Storage capacity when full	31 000 ML
Minimum operating level	EL 422 m
Capacity at minimum operating level	3 400 ML
Catchment spread	110 km^2
Historical Safe Reservoir yield (1994 GHD report)	4 800 ML/annum (13.2 ML/d)

2.2.1.2: Cressbrook Dam

Perseverance Dam	
Crest Length	20.3 m
Dam Crest level	EL 290 m
Storage capacity at crest	134 000 ML
Maximum capacity level	EL 280 m
Surface area when full	517 ha
Storage capacity when full	81 800 ML
Minimum operating level	EL 250 m
Capacity at minimum operating level	3 100 ML
Catchment spread (Including Perseverance)	326 km^2
Historical Safe Reservoir yield (1994 GHD report)	9 200 ML/annum (25.2 ML/d)

2.2.1.3: Location of Proposed Site

Cressbrook dam

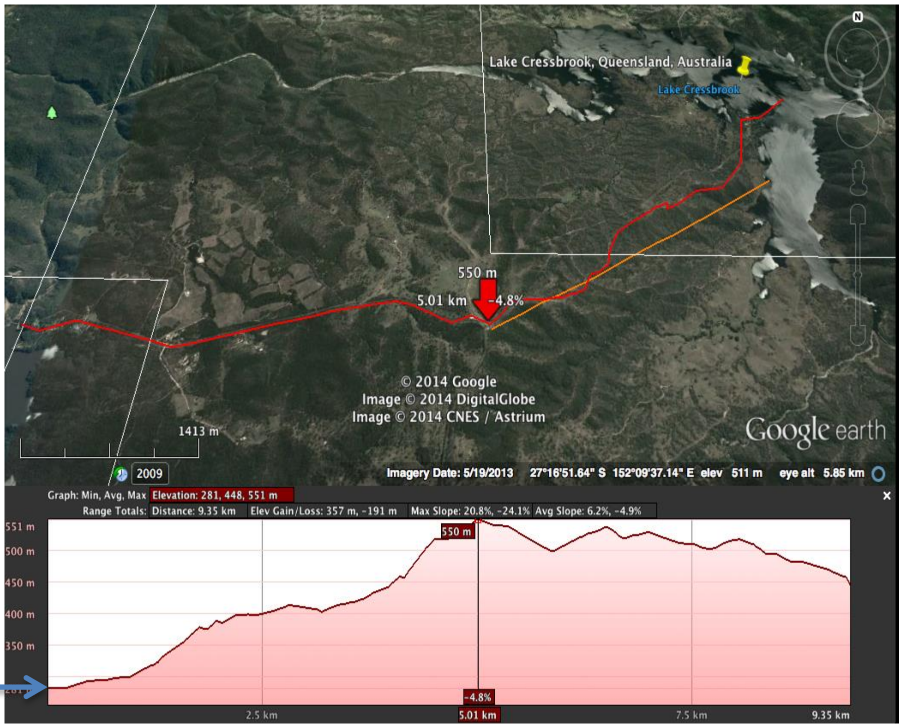

Figure 2: Location of Proposed PHES site. (Google Earth, 2014)

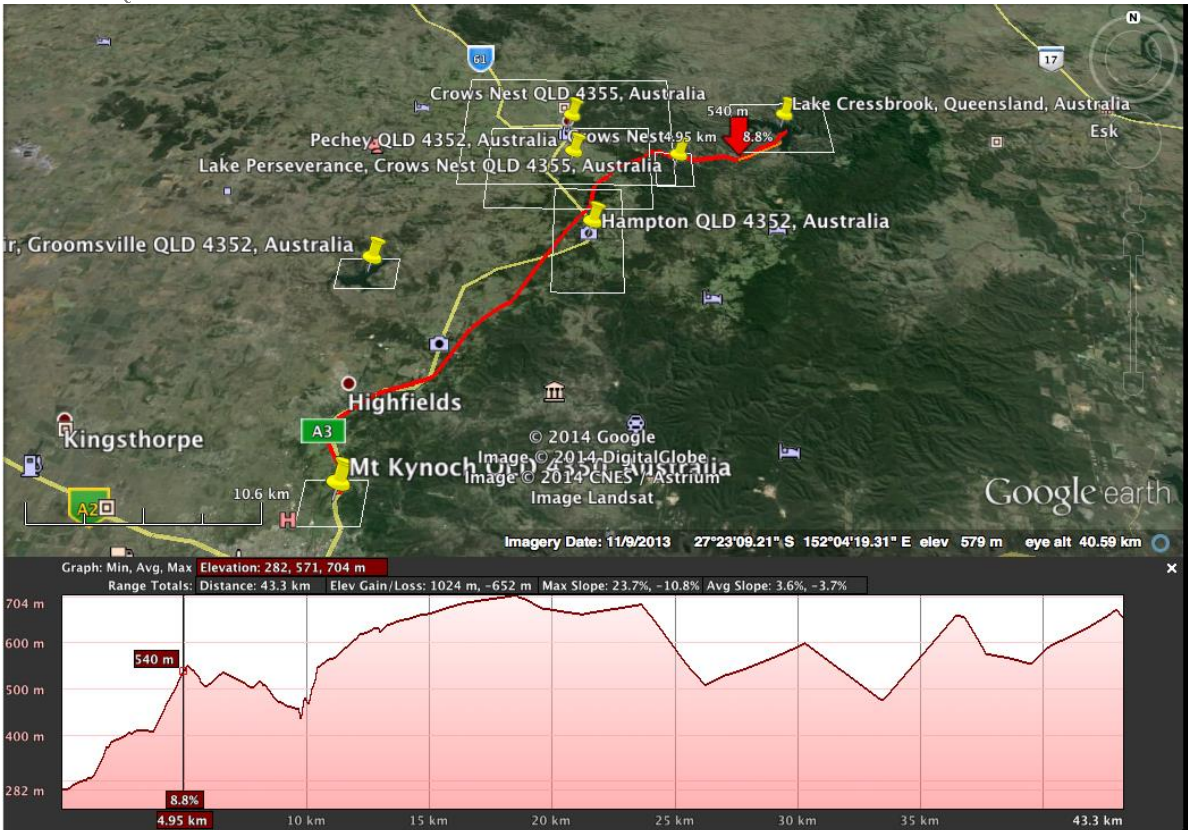

Figure 3: Pipeline system from Cressbrook dam to MT Kynoch water treatment plant. (Google Earth, 2014)

2.2.2: Bulk Water Supply Demand

Supply demand was estimated by TCC's (2002) internal assessment of the area, of which found that for long term planning 340 liters per day per person for a population of approximately 108,850 with a growth rate of 1.4% was adequate. Therefore the current total demand for the region of which these respective dams supply is 37ML/d.

The daily water demand that is required from each of these reservoirs for commercial and domestic use is of high importance when considering this project. This is largely due to the fact that the suggested hydro project will be continually shifting large amounts of water between reservoirs whilst operating, and in doing so creates the possibility of creating a bulk water shortfall for the region. This possibility is even more likely to occur in times of drought when water restrictions need to be enforced. Thus consideration needs to be taken here when generating or pumping to ensure that a water shortage is never to occur as a consequence of the PHES's operations.

2.3: Project Cost

For the purpose of this costing section the proposed PHES system will be assumed to be operating for 24 hours per day, having 12 hour pumping and generating cycles. Additionally a PHES station rated at 500 MW will be the main focus of investigation with all project costs based upon this arrangement. For modeling purposes other capacities may also be considered, but to obtain a good baseline of project costs a station of 500 MW was chosen as it is the worst case scenario. It should be noted that the 500 MW option is excessive however as the required capacity of the dam needed to supply such a station is approaching the possible upper limits if a 12 hr pumping/generating cycle is used.

For a 100 MW station the instantaneous flow rate is approximately 75 m^3/s with a daily volume of 3,200 ML. Additionally for all construction costs being headwater storage catchment earthworks, dam construction and all other necessary work to be carried out, the full construction will approximately cost 270 million.

It can be assumed that operation and maintenance costs for the hydro plant will likely be the sum of 0.05% of the initial investment per annum for the civil works and 1% for the mechanical and electrical equipment, or approximately 1.5-2.5% of the initial investment with an expected working life of 40 years[13].

2.4: Afternoon Shoulder Demand and Intermittent Generation Systems Effects

The afternoon shoulder demand for not only Queensland but also Australia is of special concern within this project. This is largely due to the impact that the various PV systems in Australian and Queensland are having upon it, and is quickly becoming an area of concern. Solar generation is ever increasing at quite a rapid rate and thus becoming more prevalent within the electricity grid, with its impact continuing to worsen if not addressed. For example in 2009 Australian PV capacity was around 180 MW, of which now has grown considerably to approximately 3 GW of installed capacity[14]. This growing renewable generation capacity is great allowing homes to become electricity self-sufficient reducing the impact that conventional generation systems are having upon the earth. However with the many benefits solar power brings to people, it brings problems also for the electricity grid and its operators.

Solar generation was originally not recognised in AMEO'S forecasting, as its contribution and impact on the system was so minor. This now however is not the case with rooftop PV growing from approximately 23 MW in 2008 to 1,500 MW by the start of 2012. Additionally this figure is forecast to rise further, reaching around 12,000 MW by 2031 under a moderate growth scenario. Under a rapid growth scenario the rooftop PV in Australia could account for 10% of the gross power generated by 2031, as opposed to 2011where it accounted for only approximately 0.6%. This is quite a substantial growth rate, and as a consequence PV currently and will continue to have an increasingly significant impact upon the grid. Due to this AMEO now releases a rooftop PV document detailing its analysis of the existing PV capacity and forecast generation levels alongside the other forecasting reports[15].

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13 (I. I. R. E. Agency, 2012)
14 (Parkinson, 2013)
15 (Wright, -)

The electricity grid was also originally designed to be a one way system from the generators to the customers. Rooftop PV is now effectively splitting this originally unidirectional supply chain into a two way system that of which it was not designed for. This creates clogging and compromises grid security, but only in times of high solar radiation. When there is low sun saturation across the PV systems (which can change rapidly from a high saturation state) consequently the adverse happens and a power deficit within the system can result. This then forces the conventional means of generation to be ramped up to compensate, with power having to be imported off the NEM whilst the large generators are in flux. This is an ineffective and costly solution, and with the projected increases in solar capacity in Australia the problems will only worsen.

2.4.1: South Australian demand variations

The possible future implications that grid installed PV generation could cause is already becoming most evident in South Australia. The PV systems within South Australia are becoming an issue even whilst their presence is effectively reducing the total state demand. This reduction in demand from such generation is not only reducing the overall demand, but is changing the historical peak and shoulder demand levels and most importantly the transition times between the two. This trait is problematic and evident within the figures 4 and figure 5 below with the pink profile being of primary interest.

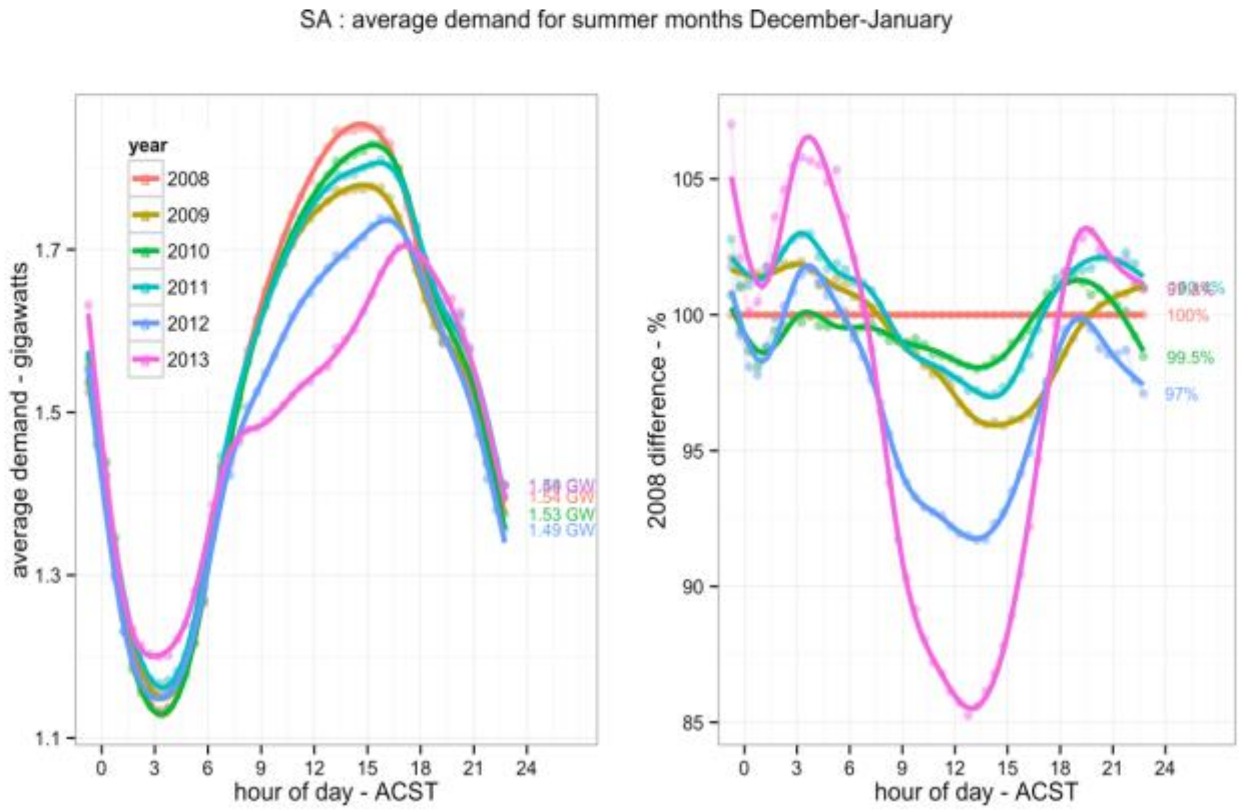

Figure 4: SA average demand for Summer December – January. Mike Sandiford Melbourne Energy Institute. (Parkinson, 2013b)

Figure 4 shows South Australia's Average Demand for the summer months, December to January from 2008 to 2013 with the second graph depicting the percentage difference of each year from the base reference year 2008. It should also be noted that the summer months is when the installed PV has the highest grid penetration levels due to this period yielding the highest daily solar exposure levels.

Rooftop solar alone was contributing 2.4 percent to the total demand in 2013, with more than a third of the installed PV generating though the shoulder/peak demand period[16]. This is apparent within the demand profiles above, as the shoulder into peak period in 2008 approximately between 9am to 3pm is significantly more than 2013. Furthermore 2008's profile is quite a predictable and definite demand progression; as the years progress this demand progression becomes more sporadic and unpredictable.

The second period of note is the shoulder and peak periods between approximately 3pm and 7pm. This transition into peak period is much more abrupt in 2013 as opposed to the previous years. The difference see here is due to the time of day, the installed domestic PV and demand. Customer demand though this period is at the highest levels for the day, whist at the same time sun exposure is diminishing. This prevents the PV systems from continuing to generate and users to be electrically self-sufficient, and thus forces customers to switch back onto mains power. For example the afternoon demand in 2013 is 15 percent less than at the same time in 2008. Then as the nighttime peak period approaches the demand in 2013 effectively transitions back to being higher than that was seen in 2008.

This universal drop in PV power coupled with demand being at peak leads to the demand profile in figure 4. These sharp variations in demand in 2013 as opposed to previous years puts the grid under increasing pressure when trying and compensate, compromising grid security.
The severity of this change from 2008 to 2013 is more prominent within the percentage difference graph in figure 4. The drastic difference coupled with the rate of variation change here is concerning not only because of the immediate concerns but also because the cause of this, being the installed PV systems are ever growing not only in South Australia but Australia as a whole.

Furthermore PV has also changed the peak period time and demand at peak times, again signifying the impacts that PV is having upon the grid. With reference to figure 5 showing the peak demand for summer months profile and the percentage difference graphs, it clearly shows how the peak period has been moved more into the night as opposed to late afternoon in previous years. Again this is because the PV systems are taking the load throughout the day, then as night approaches grid energy is then required once again.

A special point of interest should be taken also between approximately 0900 and 1600 hours on the percentage difference graph. The Demand here has gotten progressively less and less as this is the period where PV generation is most effective and has the highest penetration. The 2013 profile in regards to the 2008 profile actually goes below the historical demand, and is also considerably much less than the other previous years also. This is of benefit as less gird power is needed as more green renewable energy is being utilised. However the problem arises here approximately around 1500 to 1800 as the solar intensity decreases and the penetration

16 (Parkinson, 2013b)

of the PV is drastically lessened. This leads to a sharp increase in demand, where the 2013 profile exceeds the 2008 and 2010 profiles in a very short time. Conventional bulk grid coal fired generators cannot react to this change promptly enough with other means of generation are needed to compensate for this change[17].

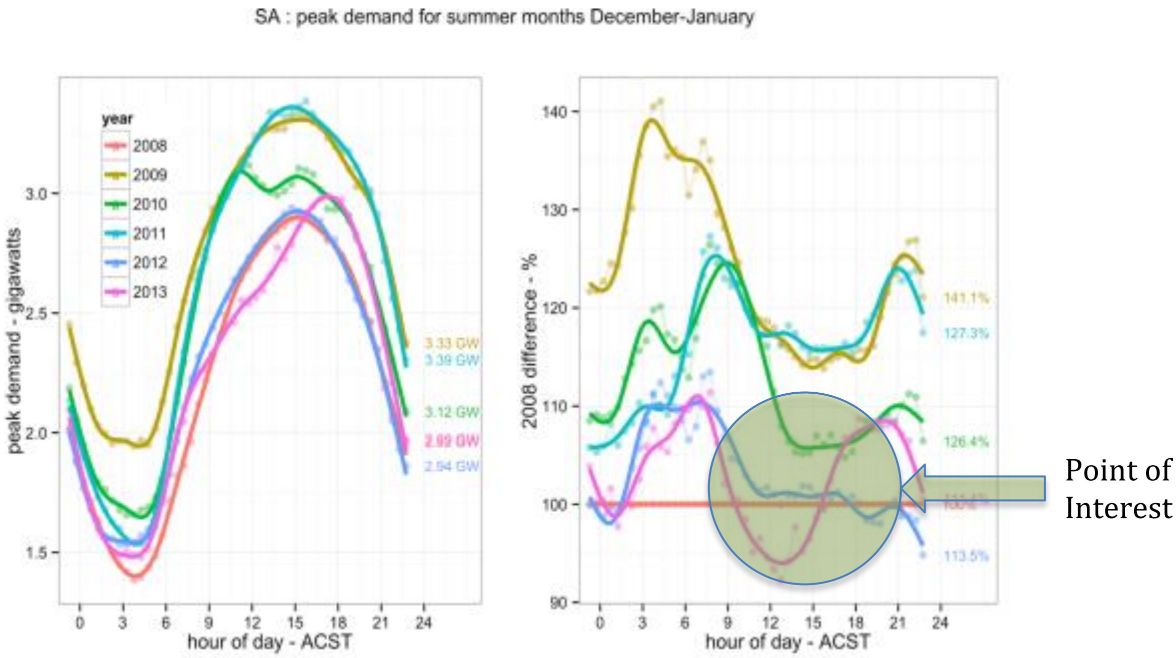

Figure 5: Peak Demand In SA for summer months. (Parkinson, 2013b)

This sharp increase in afternoon shoulder demand due to the reduction in solar intensity as the sun goes down can be made more unpredictable with the addition of unknown weather events occurring such as cloud cover. Factoring in weather as a major contributor to the effectiveness of PV, again makes the future demand profiles change once again adding to the unpredictability.

This is the problem SEQ is facing due to the afternoon weather front that can occur on a large scale rapidly, changing the forecasted peak and shoulder demands on a daily basis. This then leads to the possibility of large and fast increases in demand that conventional generators simply cannot compensate for due to the increasing number of PV systems in SEQ like that of Western Australia, with concerning consequences.

Figure 6 shows the results of a study undertaken by Ausgrid, who measured 26,651 solar domestic customers to ascertain the summer peak demand reduction due to solar. The study found that PV reduced the peak demand by 36MW, reducing the peak by 2.5%[18]. This graph again reaffirms the fast demand increase for the shoulder periods, and signifies the behind the meter generation problem solar is having upon the grid as the bulk power suppliers simply cannot manage such drastic change.

17 (Parkinson, 2013b)
18 (Simpson, n/a)

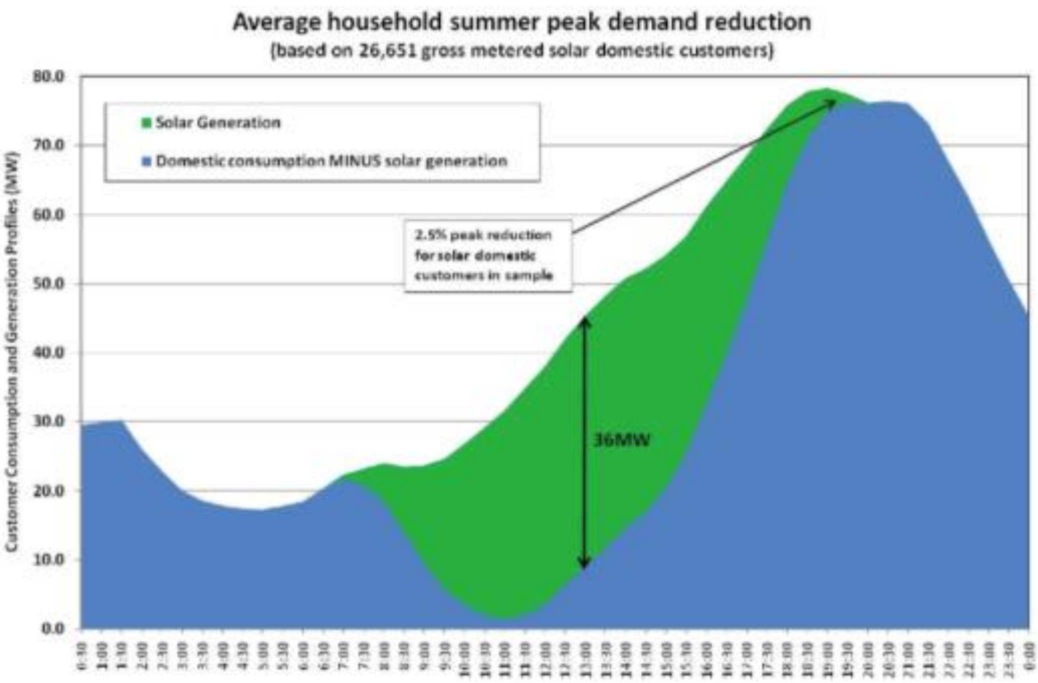

Figure 6: Demand reduction for Sydney, Central Coast and hunter Regions. (Simpson, n/a)

2.5: Optimal PHES Generating Periods

The premise of the problem is that Energex and Ergon can predict the evening shoulder peak demand, and then peak demand rollover point wrongly. This can result in the need for importation of energy for half hour periods at more exorbitant costs.

Figures 7 and 8 illustrate the issue using selected data points from the overall AEMO data[19]. Illustrated here is the real cost that can be involved in generation. Normally hydro-generation input into the grid for pumped storage applies for costs either >$100 to >$150/MWhr. So these historical records provide an idea of the contingency events which require power importation or hedging contracts for such demand.

[19] http://www.aemo.com.au/Electricity/Data/Price-and-Demand/Aggregated-Price-and-Demand-Data-Files/Aggregated-Price-and-Demand-2011-to-2015, accessed 13/05/2014.

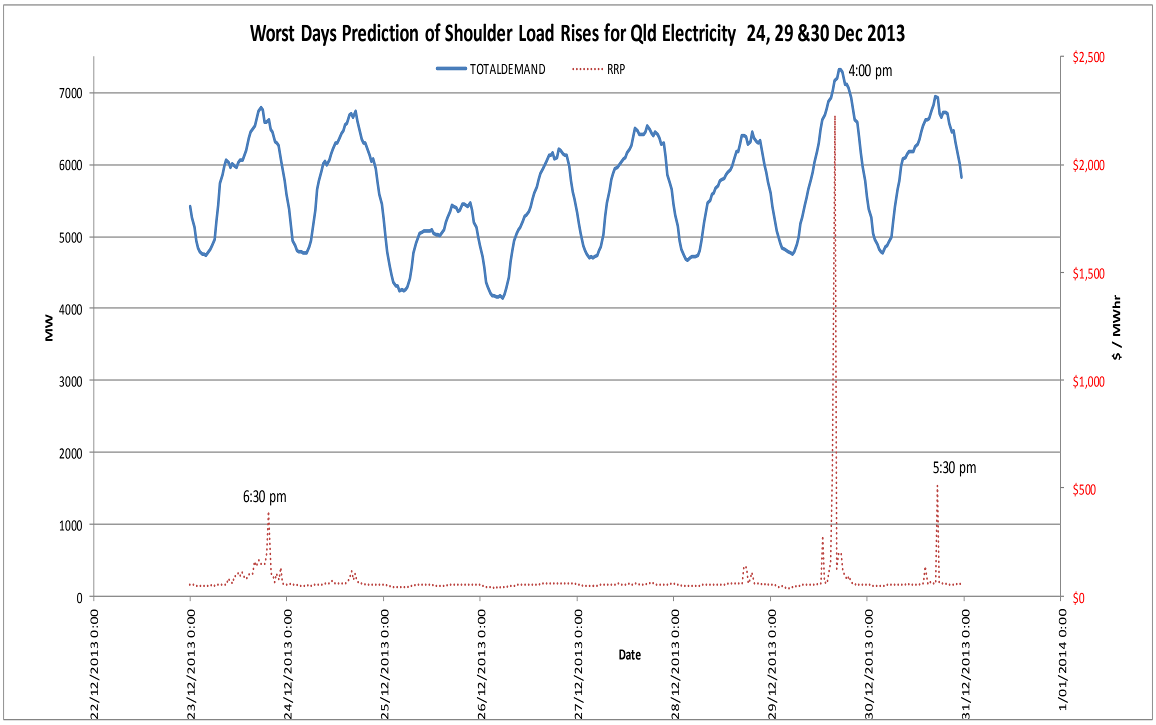

Figure 7: Worst Days Prediction of Should Load Rises for QLD (AEMO, 2013)

Figures 7 illustrates the evening summer peak prediction process occurring around 7 p.m.; with Figure 8 similarly illustrating the afternoon shoulder rate of rise of energy demand in mid-winter that coincides with the beginning of people to return to their dwellings. Predicting such rate of rise and peak is difficult for power supply / generation authorities and this is the market that pumped hydro-generation can participate in, especially when considering the increasing PV implications and the effect it has here.

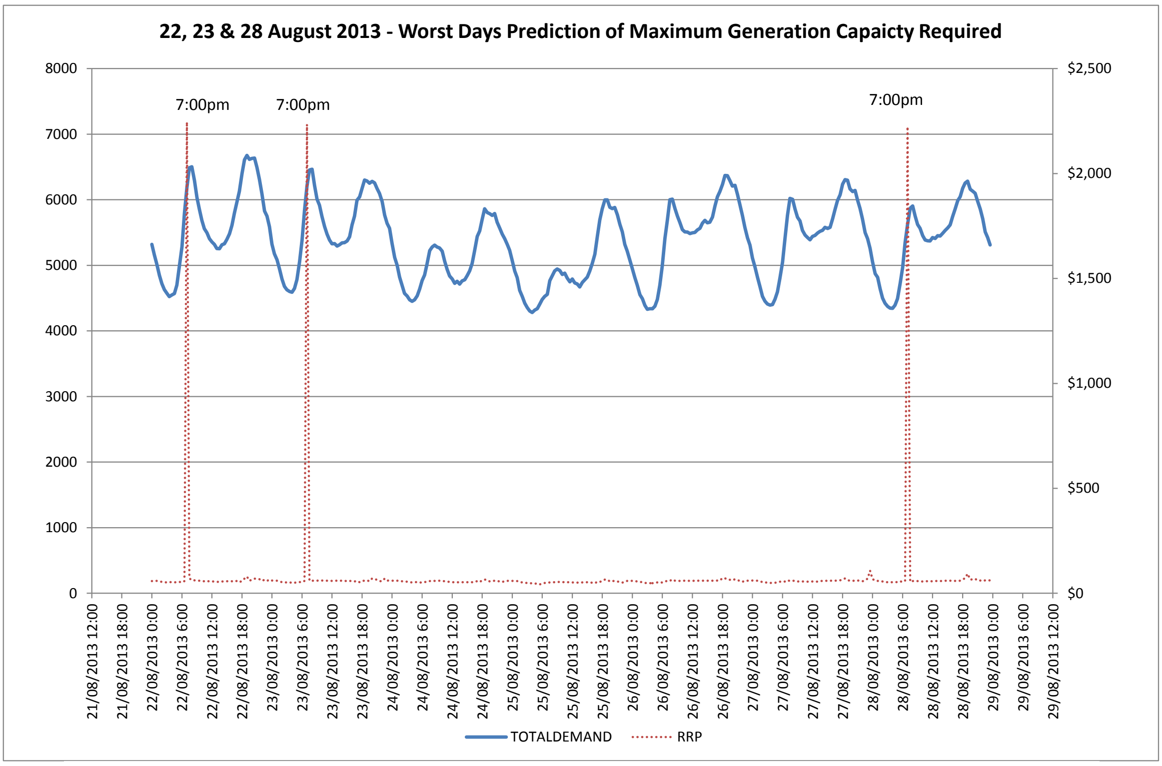

Figure 8: Worst Days Prediction of Minimum Generation Capacity Required. (AEMO, 2013)

There are several sharp spikes evident within both graphs with certain periods the cost of electricity exceeding $2,000 dollars per megawatt hour. These points are essentially where demand was not accurately forecast causing a generation shortfall with power then having to be imported.

Figure 9 illustrates the weekly volume average spot price for Queensland from 08/06/08 to 08/2/14[20]. Due to graph taking into account only the weekly averaged prices, the actual cost per megawatt hour at the time of occurrence would be much higher and needs to be considered.

This data will be used within the excel model to estimate at what cost the trade of electricity effectively has to reach before it is viable to bring online the PHES system to generate. Consideration on all investments and running costs involved along with the quantity of purchased power needed for pumping needs to be accounted for.

What has previously largely hindered such intermittent ancillary services in Queensland is that there is currently no large-scale switchable load feed-in tariff specifically designed for such stations. Currently large scale consumers requiring a demand over 100MWh per annum are charged not only for the energy consumed, but are additionally charged for each kilowatt per month of chargeable demand. For example a system that requires a load of 30MW for a singular hour over the period of one month will be billed for the entire month.

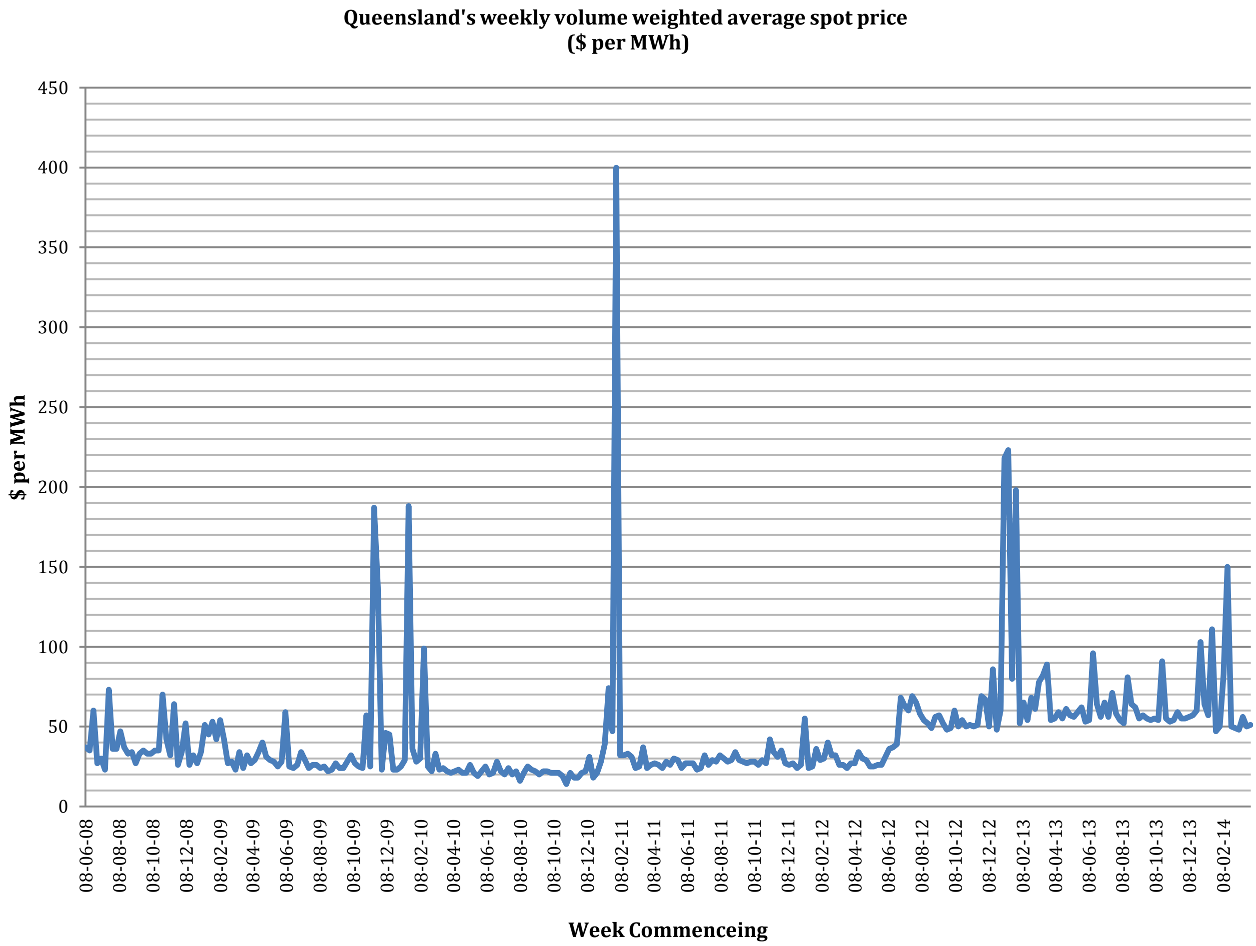

Figure 9: Queensland's Weekly volume Weighted Average Spot Price
(A. E. Regulator, 2014)

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20 (A. E. Regulator, 2014)

Under tariff 44 – businesses over 100MWh per annum (Demand Small)[21], the demand charge cost alone for a 30MW plant would equate to 1.15 million dollars per month regardless of time used plus energy consumed.

This demand change that utility scale tariffs impose in SEQ make intermittent generation/demand plants like that of a PHES station simply too expensive to deem a viable option. Such systems would only require grid electricity on rare occasion as opposed to other clients of similar scale, where having such a fee for infrequent electricity use is simply unrealistic and not sustainable.

If such a system like that of the PHES one proposed here was to use this tariff it would cost approximately upward of $80,000 per day. This is if the system where to operate for 240 days per year, with a ten hour pumping period at 30MW.

2.5.1: Future implications

The PV penetration and intimacy problem is only forecast to worsen as the year's progress, of which Figure 10 depicts. For example 2018 is forecast to be possibly as much as up to 70 percent less though the middle of the day of which then after this period and PV trend reaming, there is a sharp and drastic increase in demand once again as discussed before. Demand could possibly go from 30% less to up around 107% more than the demand in 2008% in a three-hour period. This yet again signifies the detriment to grid security PV is imposing upon the systems in Australia, where fast acting ancillary generation capacity needs to be installed to ensure that there is enough such capacity when needed to keep the power grid stable. One such means of generation is PHES[22].

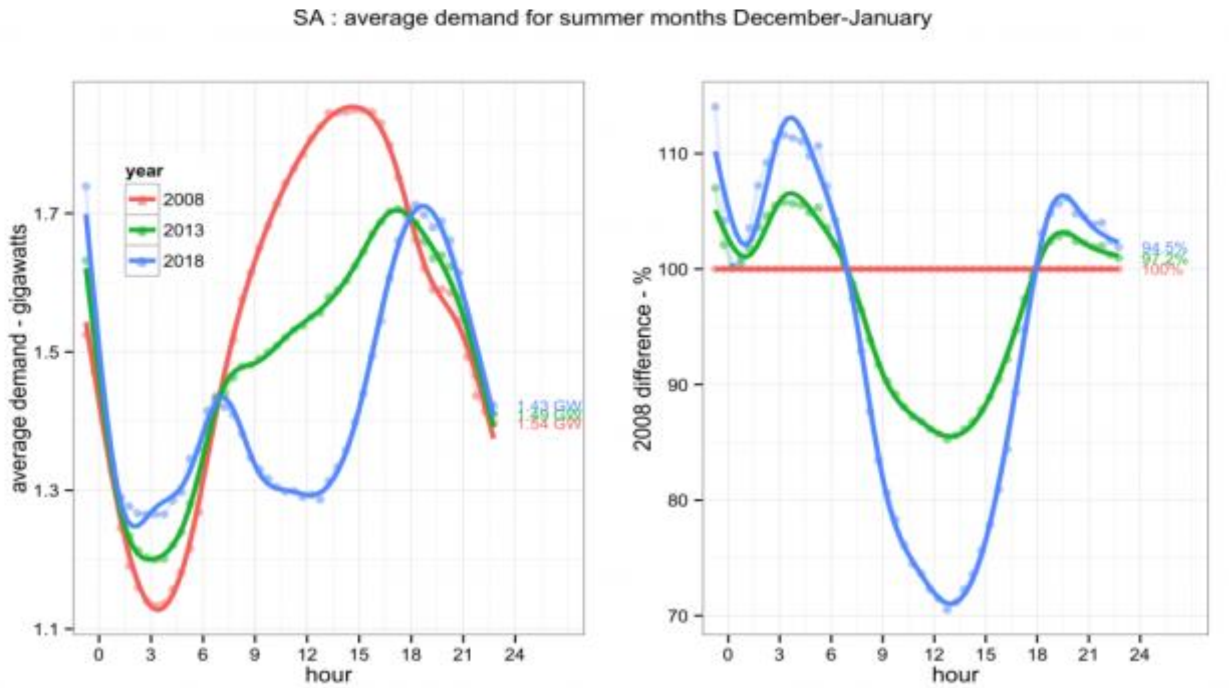

Figure 10: Future Demand In SA for summer months. (Parkinson, 2013b)

[21] (Dr Malcolm Roberts, 2014)
[22] (Parkinson, 2013b)

Based upon these forecasts the prognosis is not good being clearly evident in figure 10 also. Once again such a drastic rise in demand in a very short period of time coal fired power stations just cannot adapt. If this trend is going to continue not only in South Australia but all over Australia, without adequate generation capacity to counterbalance the effects grid security will be compromised affecting all customers upon the mains supply.

2.6: Current Relevant Trends within Thesis

This research project has been constructed heavily reliant upon several current trends within the solar industry and electricity market, which are currently evident within not only Queensland but Australia also. These trends within each industry have largely been driven by the variations within the opposite market, each being somewhat of a catalyst for the changes within the other cyclically.

2.6.1: Photovoltaic Trends

The Climate Commission released a report upon the solar generation within Australia that of which underlined a major finding, that the growth of the installed PV within Australia has already exceeded the forecasts[23]. This is largely due to advances within the technology with it becoming cheaper being a quarter of the cost as opposed to ten years ago, even without the solar rebate scheme in place with solar/grid parity being achieved in more places across Australia. With parity being achieved and more people becoming energy conscious, it is only natural for the solar capacity to rise within Australia as it continually becomes a more attractive option then being grid connected. This is so much so that it is predicted solar generation will account for 29% of Australia's total energy needs by 2050[24].

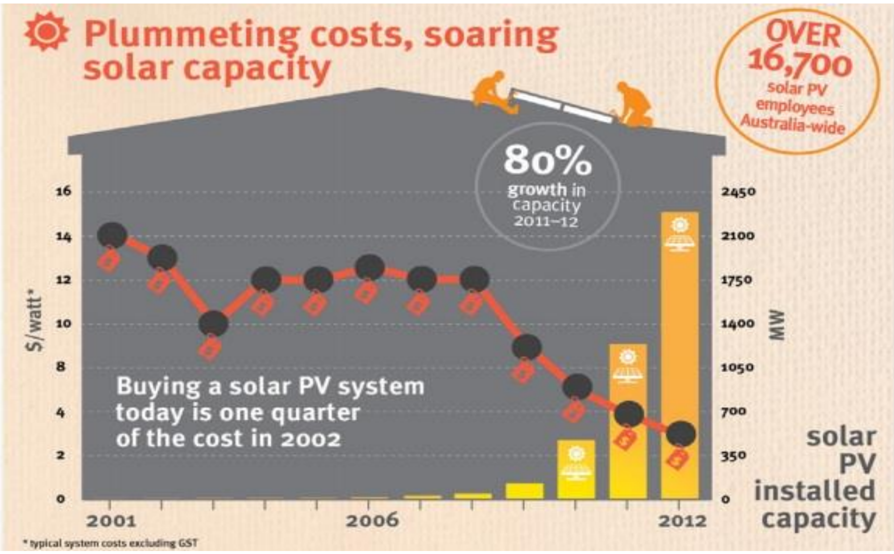

Figure 11: Current solar capacity increase and cost decrease trends within Australia. (Castaneda, 2013)

The PV growth is Australia has been very rapid. For example in 2009 the solar capacity in Australia was approximately 180MW. Then in 2013 within period of only four years, the installed solar capacity reached

23 (Castaneda, 2013)
24 (Castaneda, 2013)

3GW in total with the national solar penetration reaching 14%[25]. This rapid growth was largely contributed to the feed-in tariffs of which now have been abolished, however this hasn't stopped the trend of more people moving towards solar power. The slow propagation of solar is now being driven by the increasing costs of grid power as opposed to the benefit of feed-in tariff. More people are choosing to be energy self-sufficient with the cost of the solar system being paid off within a few years, as opposed to having to fund constant and ever increasing energy bills.

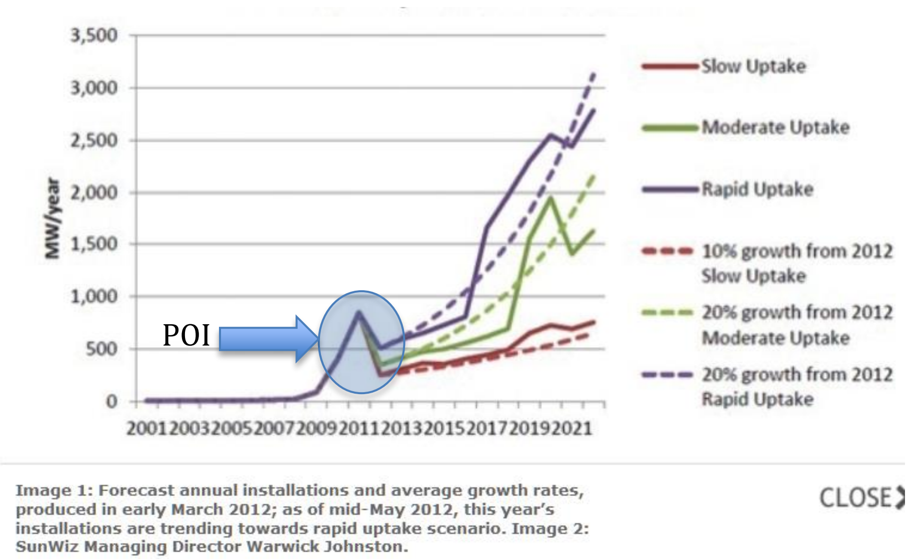

Figure 12: Australian PV industry growth forecasts (Johnston, 2012)

The events mentioned directly above are higlighed by the point of intest (POI) within the above figure 12, with the data from 2012 onwards being the forcast increases. The sharp increase in PV installations where because of the feed-in tarrif incentive, with the sharp decrease again resulting as a consequence of the abolishment of this incentive. However after this the solar uptake rate regained momentum and if forecast to steadily rise onece again at varying rates depending on each growth scenario.

AEMO has modelled several PV growth rate scenarios for Australia to produce the predictions as shown in figure 12 for the years 2012-2022. The results from this study showed that the entire installed PV capacity will reach at minimum 6 GW by 2022 under the slow uptake scenario, with the fast uptake scenario approximating that 18 GW could be achieved within the same time frame. Therefore PV by 2022 could possibly be contributing 9 to 20 percent of Australias total generation capacity[26].

Thus the assumption made within this project, that of being the installed PV generation capacity within Australia is going to continually rise over the coming years is supported and justified by AEMO's findings.

2.6.2: Electricity Price Trends

25 (Parkinson, 2013a)
26 (Johnston, 2012)

The retail cost of electricity has been steadily on the increase for many years, with high increases in not only energy costs but network costs occurring recently. For example a study into the long term changes in average electricity prices in Australia conducted by Ernst & Young Australia[27]; found that for Queensland the retail electricity price from 1996-97 to 2012-13 rose by 57%. Furthermore network prices within the same time period increased by 140%, along with other associated miscellaneous costs rising by 11% as depicted in figure 13. This has led to an increase of $932 for today's average electricity customer on their electricity bill, with an additional $619 increase upon the network bill.

	Government-owned		Privately-owned	
	NSW 1996-97 to 2012-13	Qld 1996-97 to 2012-13	Victoria 1996 to 2013	SA 1998-99 to 2010-11
Retail electricity prices	+83%	+57%	+28%	+23%
Network prices	+122%	+140%	-18%	-17%
Non-network costs plus other costs*	+51%	+11%	+72%	+86%

Figure 13: Long term change in Average annual electricity price. (Young, 2014)

In addition to this electricity costs are forecast to continually keep rising as detailed within AEMO's Economic outlook information paper 2012[28]. AMEO predicts for Queensland and basically the entire NEM that from 2015 forwards electricity prices will continually rise in increments of 1% to 2% per year until at least 2022. This price progression is evident within figure 14.

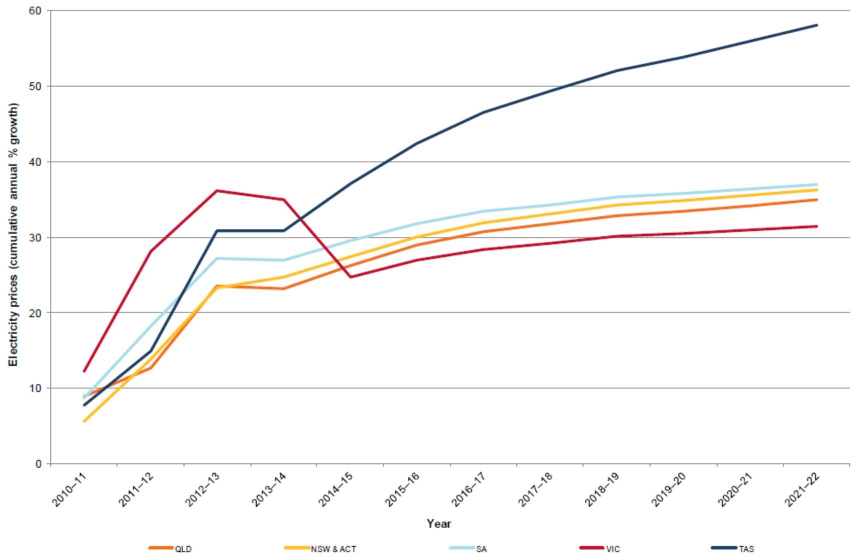

Figure 14: Australian Electricity price forecasts (AEMO, 2012)

Therefore the assumption made within this project regarding the gradual increase in the cost of electricity for several years to come is justifiable.

27 (Young, 2014)
28 (AEMO, 2012)

2.6.3: Network Cost Increase and Grid parity

Cost of electricity is forecast to rise due to many contributing factors with the installed solar systems playing a major part, however this connection is not clearly apparent. The Queensland Competition Authority (QCA) has indicated that the average domestic electricity tariff is set to rise by an additional 13.6 percent by July 2014 after previously being raised by 22.6% in 2013. Consequently the past three years have seen prices rise more than 50%, largely due to the rising costs of primarily transmission and network costs followed by retail and generation[29]. Network cost attributes for 44 percent of tariff 11's (standard residential tariff figure 15) overall cost[30], of which solar generation has largely assisted.

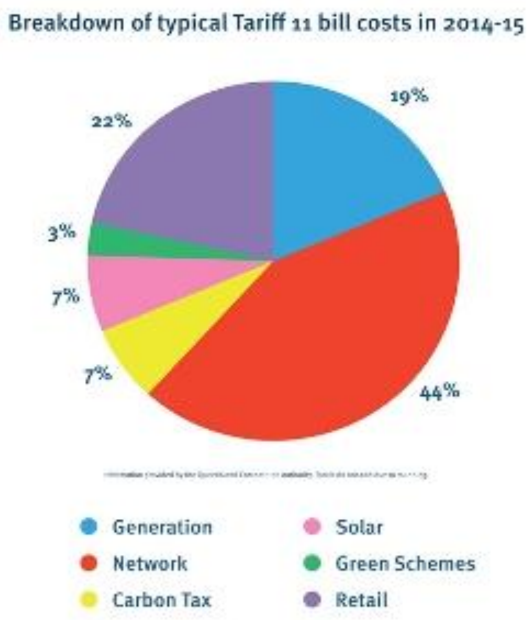

Figure 15: Tariff 11 bill cost breakdown in 2014-15. (Queensland Competition authority, 2014)

The relation to drastic cost increases and solar power again is not clearly apparent and needs some explaining. Over the last five years network companies have spent 45 billion on upgrading the transmission network. This was carried out in anticipation of future significant electricity demand increases, and was justified by the forecasted data. Simply an expanding population and ever growing dependency upon electricity will be the catalyst in driving demand up. With demand forecast to continually rise, the network companies preemptively put into action $45 billion dollars from about 2009 over five years into upgrading the system to compensate for these changes.

However at approximately the same time the upgrading commenced the total demand did not rise; it in fact fell and has continued to fall. Despite of this the network companies continued to spend upgrading the infrastructure convinced demand would once rise again. Their actions were also spurred on by the regulator of which guaranteeing them a return of every dollar plus a profit of 10%, facilitating this heavy impractical

29 (Howells, 2014)
30 (Supply, 2014)

spending. In 2012 the Senate conducted an inquiry chaired by Labor MP, Matt Thistlethwaite into the cost of electricity of which he concluded that 'What we found was those network businesses that earned the most profits were the ones that invested the most. So there was a perverse incentive in the system for an overinvestment in the poles and wires, and that led to dramatic profits for those businesses, but of course it was the consumer that paid for that cost of that additional capital[31].'

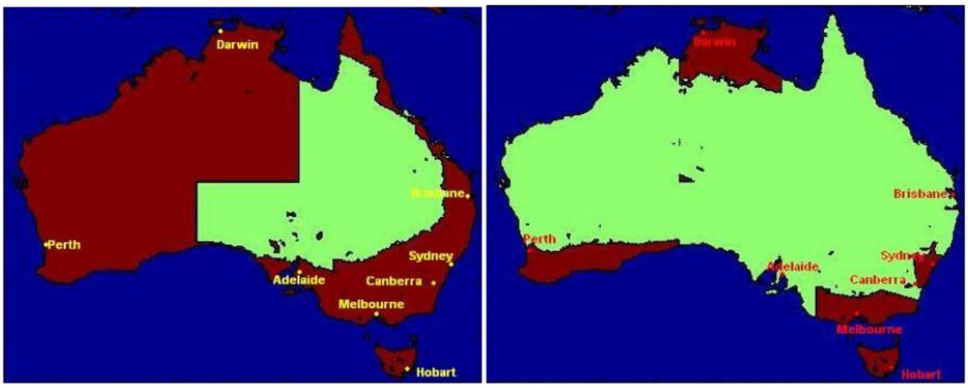

Figure 5: 2011 – 2013 solar grid parity

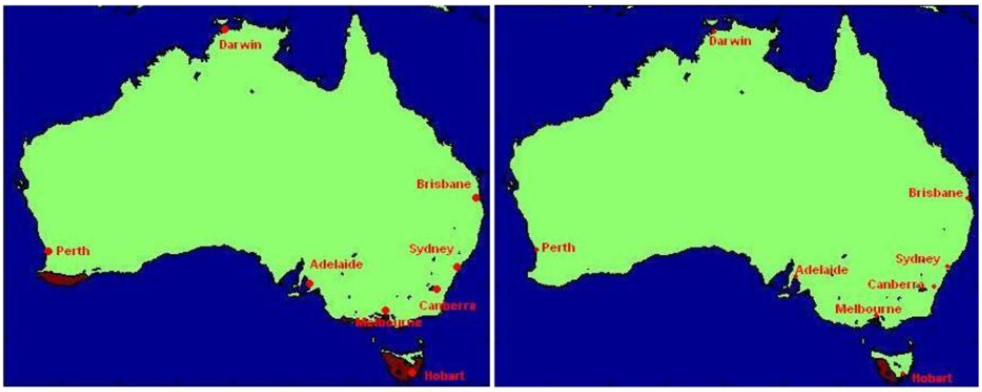

Figure 6: 2014 – 2015 solar grid parity

Figure 16: Domestic solar grid parity in Australia (Lang Chen, 2011)
Red - Non-grid parity
Green – Grid parity achieved

With a 70% rise in electricity of the past five years the costs involved with implementing a domestic solar power system is now reaching parity with grid electricity costs, even when considering the new solar in-feed tariffs[32]. Therefore with the continual rising costs of power mainly due to the overspending on unnecessary additional transmission capital (also largely due to PV), it is easy to speculate on the assumption that more of the domestic population will be driven to invest in personal PV systems as a result of this PV- grid parity.

PV is only becoming more attractive as the technology becomes more advanced thus reducing costs whilst improving efficiency, and with grid parity looming it can be easily hypothesized (See section 2.6.1) more domestic customers will make the change. If this is the case it will only intensify the problems PV is already

31 (Green, 2014)
32 (Lang Chen, 2011)

having upon the grid as capacity will increase, driving grid electricity prices higher whilst also making the demand profiles ever more sporadic.

It should be noted that Figure 16 is a generalised depection which is largely subject to change as many factors contribute to the actual onset of grid parity with each indivudal customer being different.

2.7: PHES for Renewable Integration and Power Time Shifting

One of the main issues associated with most renewable energy systems is their generation intermittency and unpredictability, affecting mainly wind farms and PV systems. Having to rely upon so many chaotic factors such as weather and other natural environmental factors each constantly in a state of flux causes such renewable means of generation to be irregular in output. As a consequence of this, integrating renewable power into the electricity grid that is highly regulated and under strict tolerances is not a simply process. In addition to this problem the times of which the renewable systems historically output power, this power may not be needed at the time of generation as demand can be easily met by the cheaper base generation units. Power cannot be stored and cannot be placed onto the grid as it would then cause an excess of electricity, in turn giving rise to many more costly problems across the power grid. However such problems can both be resolved with an adequate and effective Electrical Energy Storage (EES) system such as a PHES installation. This solution is evident with regards to figure 17. Even although this is for a wind generation system the concept is exactly the same for PHES, however the charging and discharging times are subject to change.

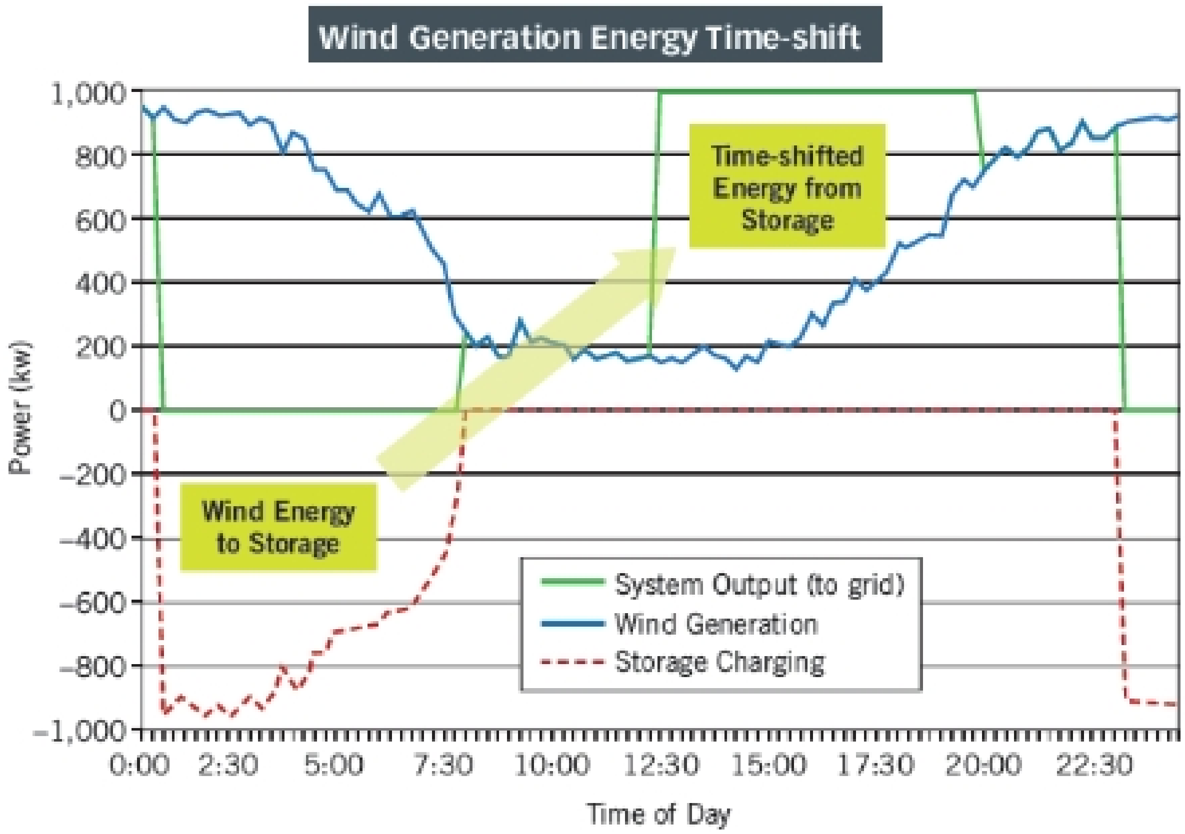

Figure 17: Wind Generation Energy Time-Shift (Pete Singer, 2010)

Times of peak generation do not always coincide with demand and therefore the power generated through these times isn't needed, with the bulk energy resources also being much more cost effective. Furthermore the constant state of flux the generated power is supplied in also is problematic to the electricity grid, of which has to be smoothed by some means to be used effectively. Effective large scale EES such as PHES can accommodate for such renewables, providing a solution to these problems being able to successfully integrate the intermittent power[33].

The power mainly in off-peak times would drive the pumping units within the PHES installation to move water from the lower catchment, back to the higher catchment effectively storing the renewable power as water head potential. This potential then can be kept here until times of peak demand of which then can be sold for high profits, as opposed to off-peak times when it traditionally would be sold where essentially it would be unwanted. Furthermore in a contingency event or when ancillary support is needed a PHES system can provide such generation quickly at any period through the day where conventional renewables cannot. Therefore emplacing such a system to readily store renewable energy has many benefits and vastly increases the usability, functionality, profit margins of owners and effectiveness of such renewable generation.

2.8: Ancillary Support and Market

Adequate ancillary support is essential to an electrical grid to maintain grid security in a number of ways. Depending upon the situation with type and amount of control required would specify the ancillary equipment needed or type of action that needs to be taken.

There are many forms of ancillary support of which are broken down into three different categories as stated in AMEO's Network support and control ancillary services (NSCAS) assessment 2012, being:

Network loading ancillary services (NLAS):

- Standby generation capable of being brought online rapidly.
- Fast runback of scheduled generating units.
- Load reduction in response to certain signals.
- Existing small-scale (non-scheduled) generation.
- Phase-shift transformers.
- Series or shunt compensation.

[33] (Pete Singer, 2010)

- Controlled series compensation.
- High voltage direct current (HVDC) links.

Voltage control ancillary services (VCAS):

- The unused reactive power capacities of generating units.
- Static reactive power compensators, such as capacitors and reactors.
- Dynamic reactive power compensators, such as synchronous condensers, static VAR compensators (SVCs), and static compensators (STATCOMs).
- High voltage alternating current (HVAC) and HVDC transmission lines.
- Control of customer load in response to certain signals.
- Installation or use of existing small-scale generation.

Transient and oscillatory stability ancillary control services (TOSACS):

- Generating plant, with properly designed and tuned power system stabilizers (PSS) for improving frequency stability and reducing any oscillatory response in power networks.
- Power flow and voltage control flexible alternating current transmission system (FACTS) devices such as SVCs and HVDC links.
- Series compensation to reduce system impedance.
- Braking resistors [34] (Above definitions taken from AEMO web site)

Hydroelectricity fits into the ancillary support market under several of these categories along with the generation market also, mainly due to its quick startup times and low startup costs. The actual startup time and cost for a hydropower plant depends on the technology used, with generally the cold startup times being approximately around five minutes, or if in synchronous capacitor mode less than 20 seconds. Also the ability of hydropower plants to readily vary the level of generation is also a very important and useful trait allowing for increased grid flexibility and stability yet again.

[34] ("Network support and control ancillary services (NSCAS) assessment," 2012)

Furthermore a PHES scheme aside from the traditional hydropower plant offers additional grid support benefits due to its added pumping capability. This function is most useful in off-peak times to aide in stabilizing the grid and to keep the bulk energy generators online, negating shutdown and startup overheads as it can create load.

However the ancillary service area of generation supply has only minor cost impact on the overall operation of a pumped hydro, as shown by the service provision cost[35] (figure 18 below).

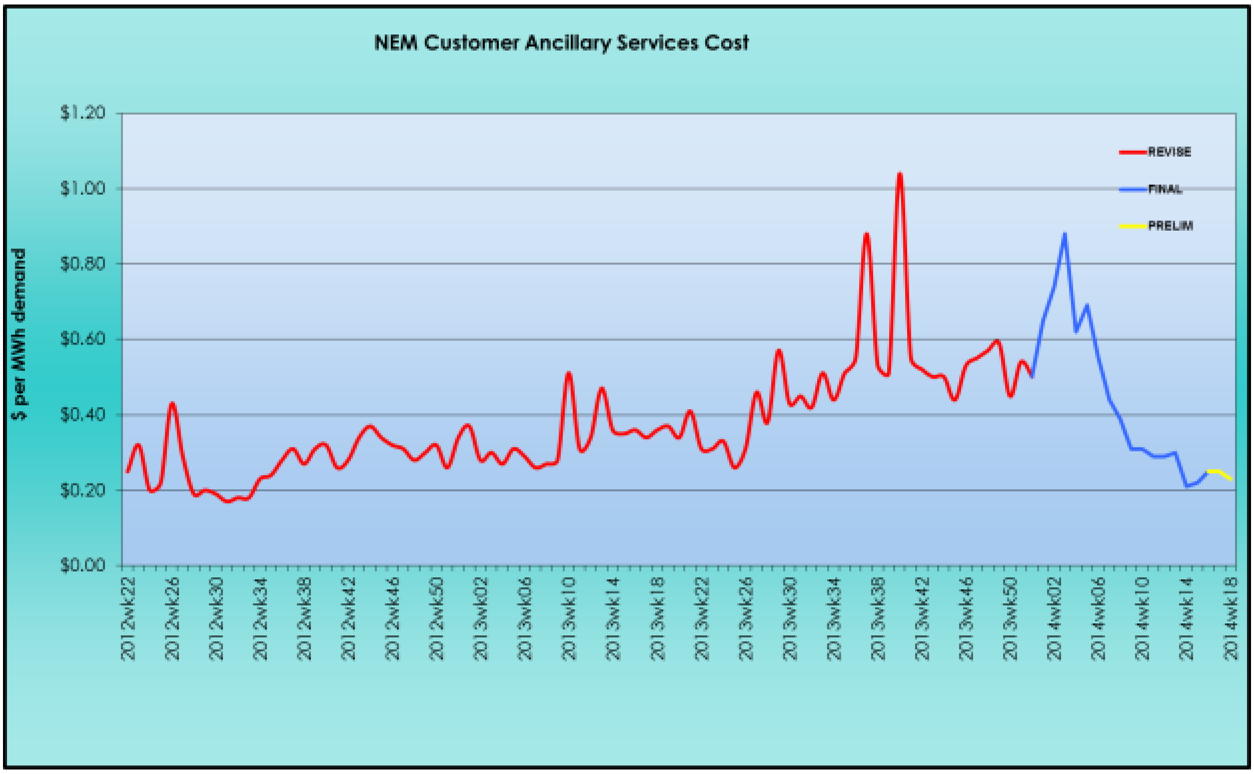

Figure 18: NEM Customer Ancillary Services Cost. (AEMO, 2014b)

Additionally in the area of frequency stability control ancillary service support, there are six response contingency based time bands, only of which two are available to hydro-generation: this is as detailed GUIDE TO ANCILLARY SERVICES IN THE NATIONAL ELECTRICITY MARKET[36]. These are

- Fast Raise (6 Second Raise) ([✗] Hydro-generation)
- Fast Lower (6 Second Lower) ([✗] Hydro-generation)
- Slow Raise (60 Second Raise) ([✓] Hydro-generation)
- Slow Lower (60 Second Lower) ([✓] Hydro-generation)
- Delayed Raise (5 Minute Raise) ([✓] Hydro-generation)
- Delayed Lower (5 Minute Lower) ([✓] Hydro-generation)

2.8.1: Synchronous Condenser Mode for Grid Voltage Support

Transmission system operators specify a voltage program of which the various generators, being conventional or variable in nature are expected to follow. This means being able to adjust their reactive power output in

35 (AEMO, 2014b)

36 AEMO, *Guide to Ancillary Services in the National Electricity Market,* Document 160-0056 Version 1.01 of 01/07/2010

order to maintain the voltage levels as specified. The ability to do this however for PV and wind generation systems relies primarily on the inverters and static compensates (STATCOM) used within the systems, being quite different to the conventional generation forms when compensating for the same factors. However the IEEE 1547.1 standard maintains that the power factor output has to be within 0.85 to unity lag or lead power factor (PF). This presents a problem for distribution PV and wind farm systems as they are required by legal statutory requirements to transmit power to a network at unity, and therefore in their current co-generation operation can offer only very little reactive power support when at maximum output capacity[37].

However this is not a problem as the Pumped hydro system can operate in synchronous condenser mode, where the system is spinning however is not generating or creating load. Depending on its operation the PHES system could effectively generate or consume volt-amperes (VAR's)

2.9: Generator and Turbine systems

The motor/generator can either be an asynchronous machine or synchronous machine with a frequency converter allowing the pump/turbine to be varied in speed. This feature optimizes the operation of the turbine when generating as the desired output can be achieved and likewise when pumping, as it allows the amount of pumping to be adjusted to best fit each demand[38]. Having such flexibility within the system is invaluable, and being able to accommodate for all pumping and generating demands within the stations operating region enables the operators to run the station at optimum levels continually.

2.9.1: Turbines

There are two main types of turbines that are used for Hydroelectricity installations being Impulse turbines and Reaction turbines. What turbine is ultimately chosen for a project is chosen in regards to height of head, flow rate, volume of water at the location with efficiency and cost also being factors.

2.9.1.1: Impulse Turbines

Impulse turbines operate upon the velocity of the pressurized incoming water, of which it is then ejected out back to normal pressure. Impulse turbines generally consist of many runners upon a wheel, of which each coming into contact with the water stream at some point to generate torque upon the shaft. At the discharge point there is no suction generated with the water simply flowing away. These turbines are most suited for high head's with low flow rates.

Turbines that come under this jurisdiction is the Pelton and Turgo wheels, and cross-flow turbines. The Turgo wheel is a slight variant of the Pelton wheel, and the cross-flow turbine was essentially created for larger water velocities at lower heads of which the Pelton wheel was created for.

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37 (Laboratories, February 2012)

38 (VIOTH, 2014)

2.9.1.2: Reaction Turbines

Reaction turbines generate power from the pressure and velocity of the water, where the runner is in the direct flow of the water not being offset at all as opposed to the impulse turbines. These turbines are best suited for low head and high flow applications, basically being the opposite of impulse turbines.

Under reaction turbines there are three main variants being Propeller, Francis and Kinetic Turbines. Propeller turbines generally have three to six blades all being in contact with the water at all times, and again there are many subtypes of this turbine also. Bulb turbines, Straflo, Tube and Kaplan turbines all fall under the jurisdiction of propeller reaction turbines.

Francis turbines consist of generally nine or more vanes, where water is injected above the vanes and falls though causing torque upon the wheel. Finally the last major variant is Kinetic turbines (Free flow Turbines) that like the name suggest, use the kinetic energy within the water as opposed to the potential energy of the head to generate torque. Kinetic turbines are generally situated within rivers, man-made channels, tidal areas and places subject to ocean currents where the kinetic potential of water is constantly oscillating[39].

2.9.2: Reversible Pump Turbine Systems

Pumped Hydro Energy Storage essentially works exactly the same as conventional Hydropower schemes, except PHES incorporates an additional pumping element along with the normal turbine unit know as a reversible pump turbine as in Figure 2. This system consists of a motor/generator with a pump/turbine making a hybrid component that can effectively undergo both generating and pumping actions.

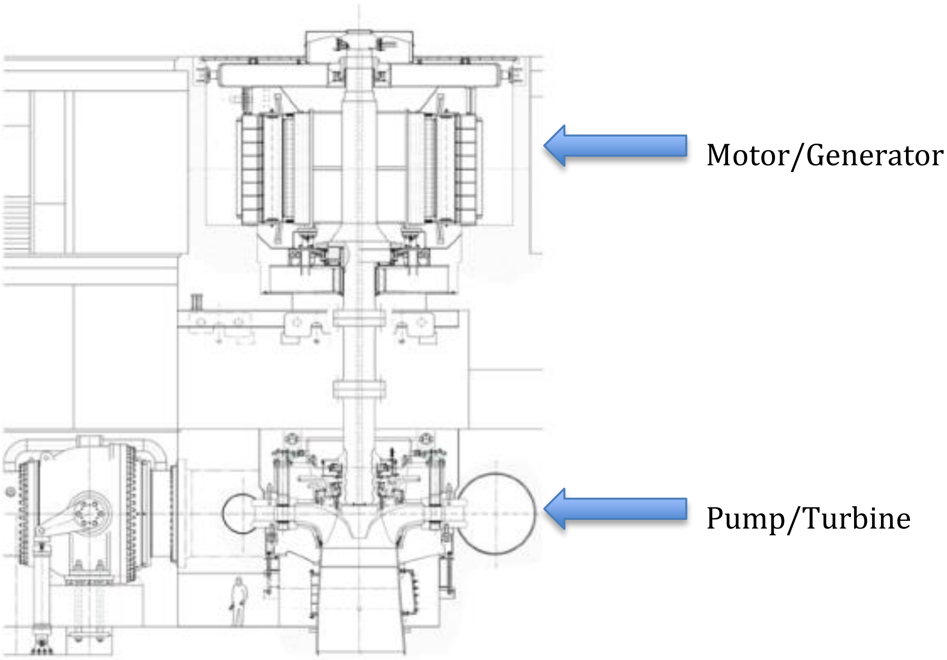


Figure 19: Cross section of pump turbine/generator unit - (VIOTH, 2014)

[39] (Energy, n/a)

2.9.2.1: Ternary Set System

The motor/generator unit in a PHES scheme can incorporate both functions within the single unit as per figure 19, or there can be an independent pumping unit along with a generator unit known as a Ternary set. This arrangement is called a Ternary set as it consists of the motor-generator, a pumping unit and a separate what is generally a form of Pelton turbine[40] as seen in figure 20. Having two individual units is generally the main approach as the technology and equipment differ for the functions of pumping and generating. Subsequently higher efficiencies can be achieved with two individual units as opposed to a universal unit, and therefore is why this method is generally used more universally in PHES stations.

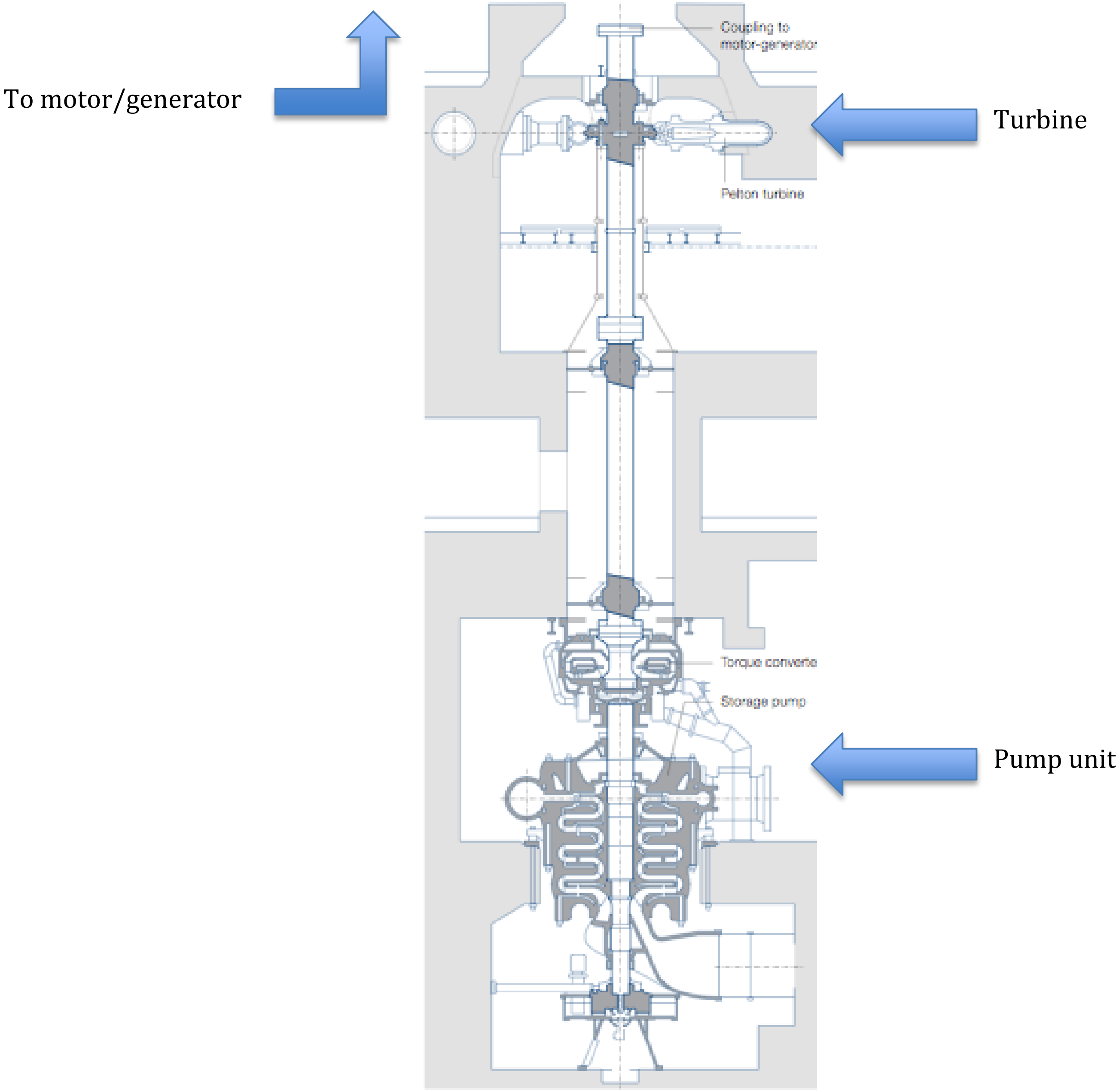


Figure 20: Ternary Set - (VIOTH,

These types of arrangements also could possibly yield additional operational benefits. For example pumping could continue whilst the system is operating in synchronous condenser mode for voltage support, as the

40 (VIOTH, 2014)

pumping and generating systems can operate independently. However operations such as this would require additional infrastructure and equipment, but could prove to be highly beneficial.

2.10: Catchments

Pumped hydro utilizes two catchments, one being at a higher potential to give the adequate head necessary for generation as in hydroelectric plants. The water catchment above is used to store the water potential for generation, with the lower catchment being the spent potential water storage catchment[41] as in figure 21. The top catchments potential is generally utilized during periods of peak demand to provide power when electricity is at its most expensive. During this period the bulk power producers normally can't meet demand alone and need such ancillary support to maintain grid security. After peak demand has subsided and the electricity time cycle goes into the off-peak period of which there is excess generation, this surplus cheap power is then used to pump the water from the lower catchment back into the higher catchment. This restores the waters potential allowing the energy to be time shifted so that it can be used once again in the peak period, making more efficient use of the electricity generated within the off peak period[42].

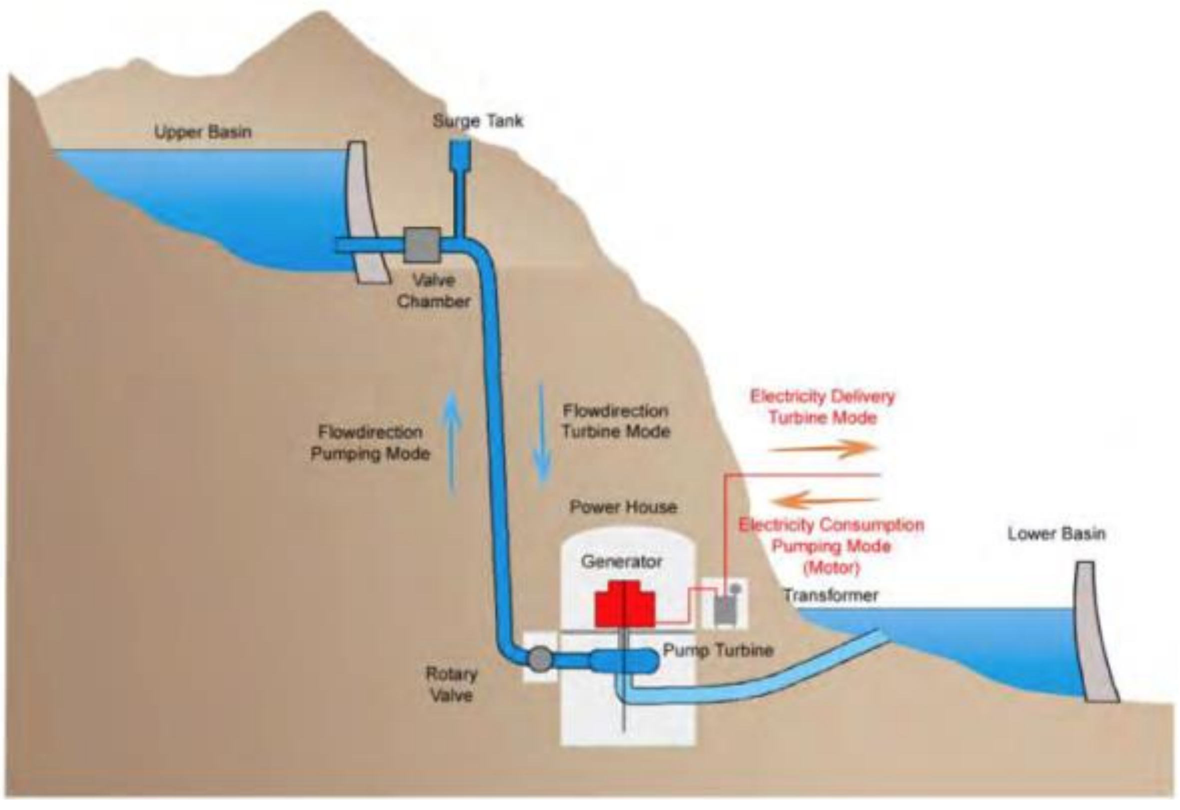


Figure 21: PHES concept – (Alstom Power)

2.10.1: Catchment Head and Flow

Head in regards to hydraulics is the amount of potential per unit weight of water, of which is gained though elevating the water above sea level by a specified amount. Generally it is defined by meters of elevation above sea level, or the total change in height from water level from one catchment to another.

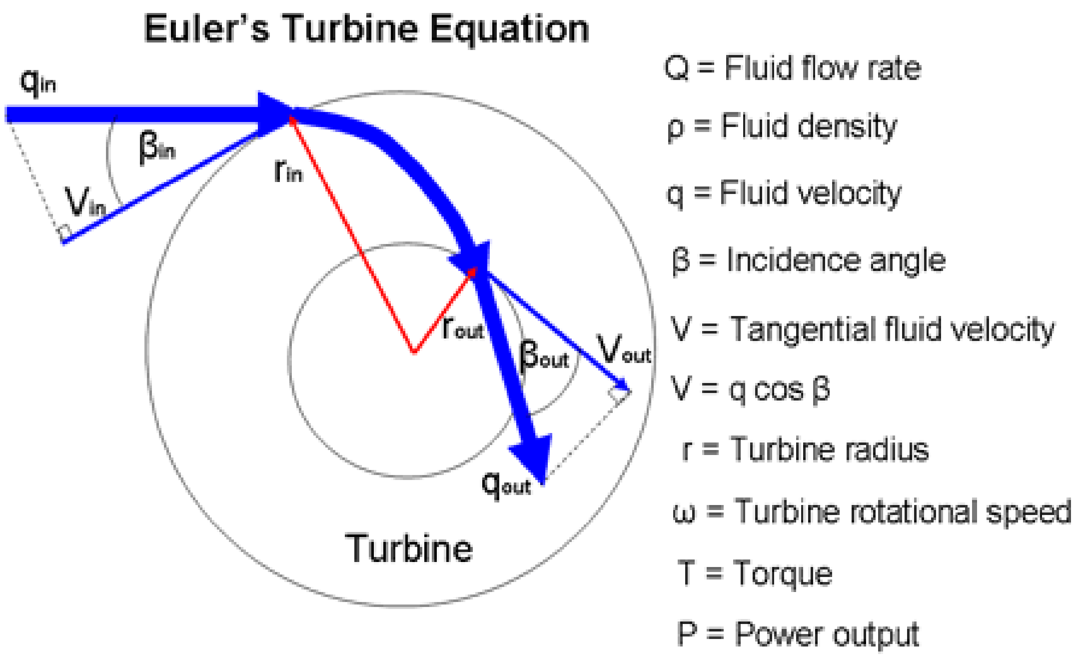
41 ("How Hydroelectric Energy Works ", 2006)
42 (Rachel Carnegie, 2013)

2.10.2: Power Output

Fundamentally all the different turbine arrangements used for Hydroelectricity conform mostly to the same set of rules that govern output. These laws are instituted in Euler’s Turbine Equation that can be used generally for all turbines to give an approximate power output. This is because Euler’s equation actually has nothing to do with the physical turbine itself or how it operates. This calculation is for the change in angular momentum of the water between the inputs to the exhaust, and thus is why can be applied to many situations.

Basically the equation first calculates torque enforced upon the shaft, which is then used to calculate power output. Basically the torque is equal to the change in angular speed of the water as it acts upon the turbine blades, then the power output is equal the torque generated upon the shaft multiplied by the shafts rotational speed[43]. The detailed description can be seen in figure 22.

Additional external factors also need to be factored in here such as the efficiency level of various components within the system such as the turbine and generator to yield accurate calculations.



Torque $T = \rho Q(r_{in}V_{in} - r_{out}V_{out})$

Power $P = \omega T = \omega \rho Q(r_{in}q_{in}\cos\beta_{in} - r_{out}q_{out}\cos\beta_{out})$

Figure 22: Euler’s Turbine Equation. ("HydroElectric Power," 2005)

43 ("HydroElectric Power," 2005)

2.10.3: Efficiency

Large-scale hydroelectric power installations are some of the most efficient means of power generation in contemporary times. This again is clearly a beneficial trait as only very little energy is being lost though the process, making it a very sustainable and effective generation system[44].

As it can be seen in figure 23, large hydroelectric power stations are currently the most efficient primary form of electricity generation in current times. It is in the order of 95% efficient due to basically all of the stored potential energy within the water can be extracted, as it is quite a simple process. The hydroelectric configuration simplicity reduces the areas that energy can be lost, as the water does not have to undergo any chemical conversions or for potential to be transferred. These two processes within power generation are historically the areas costing the various systems subject to such processes, the most in efficiency rates. For example when a coal-fired power station have to burn coal to convert water into seam to power turbines, the chemical conversion of coal when burnt with the potential energy then transferred into water to create steam is overall only around 42% efficient[45]. This figure is also for the most advanced coal fired stations in the world, still being far off the pace of hydroelectricity again mainly due to the various chemical conversions and energy potential transfers that occur each costing the system greatly. In this situation keeping it simple has turned out to be much more effective and efficient.

Also it should be noted that with increased efficiency comes increased profits also as nowhere near as much energy in is needed to get the desired energy out, being greatly beneficial to the respective utility company.

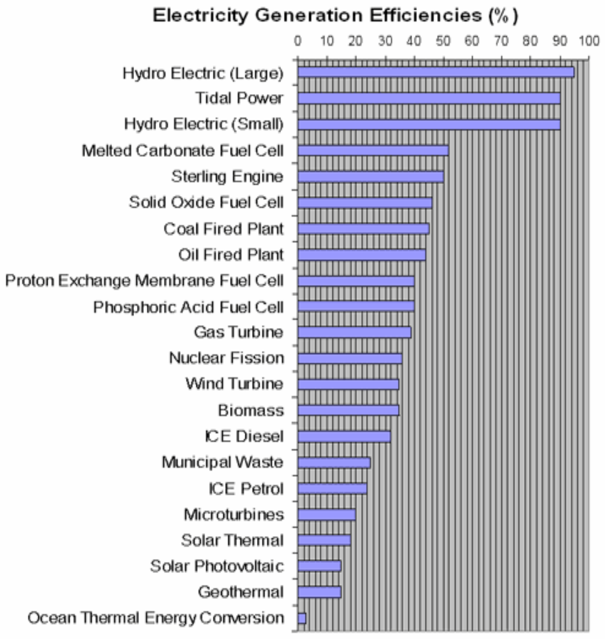


Figure 23: Electricity Generation Efficiencies (%). (EuroElectric)

44 (EuroElectric)
45 (A. C. Association)

2.11: Large-scale Renewable Energy Target (LRET)

The Large-scale Renewable Energy Target (LRET) scheme came into action in 2001 with the primary objective of achieving 20 percent renewable energy penetration within Australia by 2020. The LRET facilitated this by encouraging renewable generation sources through the use of Large-scale Generation Certificates (LGC's), which are equivalent to 1MWh of eligible renewable power generated. These certificates are created and traded in an online market between retailers in the renewable energy certificate registry, of which is managed by the Clean Energy Regulator. The Australian government then enforced a legal obligation upon all liable entities (generally non-renewable retailers) to buy and sell a specified portion of these LGC's each year to further fund and create incentive for investors to increase the renewable sectors capacity. This effectively made the traditionally more expensive renewable technologies much more appealing and viable option, and as a result the renewable sector has increased in interest, output and productivity[46].

The LGC's are traded though a wholesale spot price market, with price varying with current levels of supply and demand.

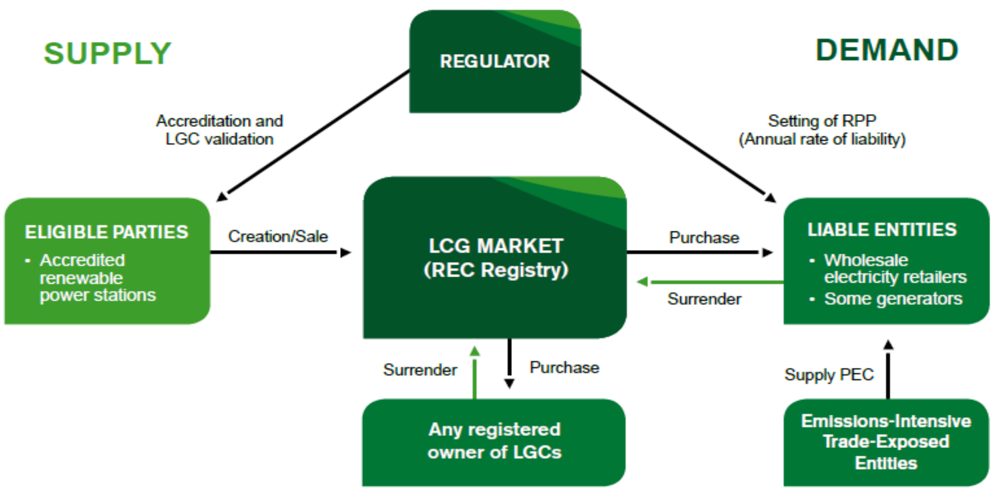


Figure 24: Large-scale Generation certificate market (A. G.-C. E. Regulator, 2012)

The LRET yields benefits for renewable power stations offering bonus revenue in addition to their normal returns, generally in the area of $22 to $32 dollars per LGC[47]. However this incentive may not continue to be in effect for much longer.

46 (A. G.-C. E. Regulator, 2012)
47 (Markets, 2014)

A review report of the renewable energy target scheme was conducted in 2014 by the Australian Government with the aid of an Expert Panel. After assessing all factors associated with the RET scheme such as performance, objectives, impacts and other topics of interest they came to two conclusions.

- Option 1 – Deny new applicants

The LRET scheme is simply too expensive and costing the population of Australia a significant amount each year though their energy bills. Therefore to reduce this cost to the public and the impact of the LRET upon the energy market, it was advised that this scheme should be denied to new applicants. Furthermore the last year of which the LRET scheme will be effectively in action for is 2030, so if a renewable system continues to operate past this point in time they seize see any benefit from the RET scheme[48].

- Option 2 –Electricity demand growth division

This second recommendation is less harsh then option 1 where a level of support is still somewhat provided to new renewable power stations, of which not totally cancelling them out. This options intention is still to reduce Australia's emissions, achieve a reduction in the LRET costs but still provide some incentive for new renewable systems to continue reducing emission from power generation. To do this the new target was advised to be changed so that it would assign a portion of growth in electricity demand to the renewable sector. Two action plans where formulated to do this and are as follows:

- The RET target is set on a yearly basis and increased every consecutive year until 2020 by 50 percent of the forecast growth in national demand. This will make sure that renewable power stations will only be supported by the RET when there is an increase in demand.
- If demand is forecast to remain unchanged in the following year, the renewable energy target also remains constant.
- After 2021 the target will remain constant at the 2020 level until 2030, being when the scheme is set to end. This option would achieve a 20 percent portion of renewables amongst Australia's net generation resources by 2020 based on current demand and forecasts[49].

2.12: Australian Energy Market Operator (AEMO)

AEMO (Australian Energy Market Operator) operates upon the gas and electricity industries across the National Energy Market (NEM) (See section 2.12.1), providing a variety of services for utility companies and the public alike. It was founded in 2009 and operates at various levels within the two industries being

48 ("Renewable energy Target Scheme," 2014)
49 ("Renewable energy Target Scheme," 2014)

generation and retail markets and controls planning, operation and development of the NEM, along with controlling the energy retail marketplaces.

AEMO's operational role covers two main areas within the NEM, having both a power system operator and market operator divisions to cover both areas. AEMO also provides some transmission services connecting generators and customers, operates the NEM, Short Term Trading Market (STTM), retail markets all in conjunction with the wholesale gas market for Victoria.

Forecasting and planning of the gas and electricity markets that are under AEMO's jurisdiction are two highly important services that AEMO provides. Future events modeling and market development scenarios are all actions undertaken by AEMO for the NEM, along with planning for increasing future capacity. AEMO provides independent electricity demand forecasts for the entire NEM, supervises development of the NEM and aims to maintain grid security[50]. Many documents are also produced by AEMO covering everything from demand outlooks, power system security guidelines and report updates for various sectors within the NEM.

2.12.1: National Electricity Market (NEM)

The national electricity market is an electricity grid interconnecting five regional markets in Australia being Victoria, South Australia, Queensland, New South Wales and Tasmania. Electricity on the NEM is sold on a wholesale basis and transmitted to the various power distributers in the NEM, of which then on sold to customers.

A spot market is used to trade the electricity that is generated by the utility companies to the customers. The total power generated over the NEM is combined into a single energy mass collation, of which in five minute intervals is scheduled out to meet the demands of customers across each region in real time though a central dispatch.

50 (AEMO, 2014d)

Each energy company makes bids to AEMO to provide the NEM with a set quantity of power, at a set price over a specified period of time. From the bids AEMO decides what generators will be used to meet demand, with obviously the cheapest being utilized first. Prices are governed primarily by two factors, first of all being the bids offered from the generators at any point in time and the total demand upon the NEM[51].

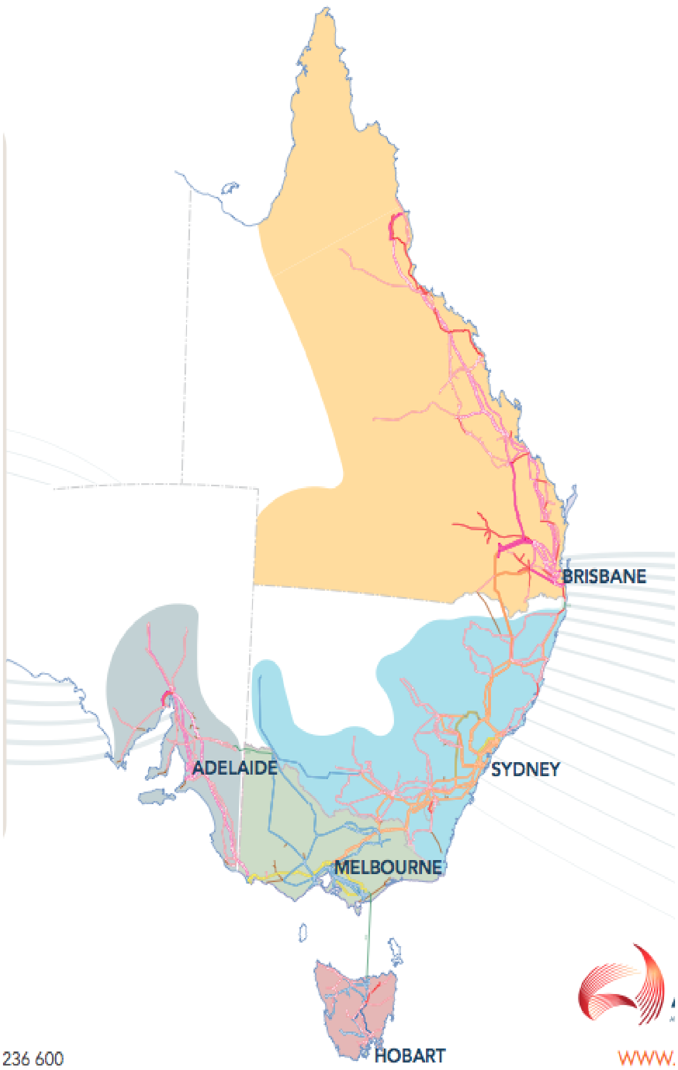


Figure 25: National Electricity Market regions and infrastructure. (AEMO, n/a)

The NEM is the longest AC system in the world with 40,000 km of transmission lines encumbering 9 million everyday citizens and provides approximately 200 TWh to customers[52].

2.12.2: AEMO Forecasting Introduction

Forecasting is carried out by AEMO to predict demand on a seasonal and regional basis over a seven-day outlook period for each NEM sector. Historical supply and demand data in conjunction with specific regional variables are used to model and predict future demand[53]. The changing of seasons is a major factor taken into

51 (AEMO, n/a)
52 (AEMO, n/a)
53 (AEMO, 2011a)

account as each passing season plays a major role on demand levels, how energy is consumed and times of load variations specific to each season. Having seasonal trends with the analysis of historical data greatly aids the ability to effectively forecast energy consumption, as previous data retained can be used to create effective models. However with the addition of intermittent behind the meter generation sources to the contemporary system mainly being the large and ever increasing installed renewable PV generation capacity, conventional forecasting methods are becoming much less accurate.

The addition of intermittent renewable generated power from millions of random individual users coupled with the additional detrimental effect of significant weather events upon such system makes for quite a sporadic and chaotic daily load profile. Trying to predict such a chaotic system is very difficult, and if the predictions are off this can lead to exceedingly high-energy prices. High levels of electricity wastage due to excess power within the grid, or inversely insufficient electricity within the system are also possible consequence. This compromises grid security and makes for expensive and troublesome events such as rising the system voltage levels for example, leading to further network problems. Furthermore additional future variables are also possible that could add to the pre-existing problem such as changes in economic activity, population fluctuations and changes in generating and consuming technologies.

With so many pre-existing and possible future impacting factors, the energy supply system in Australian can easily grow more chaotic[54]. As a result forecasting methods need to advance with the times always having to be constantly adapted, or the production and distribution of power will become very difficult to maintain within the many strict set tolerances.

Electricity forecasts are of great importance and use to utility companies primarily due to that electricity cannot be readily stored. Poor forecasting increases energy wasted and leads to large overheads potentially costing utility companies significant revenue. This is why accurate forecasts are so important, as they effectively allow the utility companies to operate efficiently as possible reducing wastage. Accurate forecasts provide insight into how daily energy production operations have to be varied in regards to demand, offering adequate pre-warning of demand events so that compensation measures can be easily implemented for future occurrences.

This is beneficial not only to the power companies as it increases profits but also to the environment and consumers, which are also of great importance[55]. Also forecasting is conducted across many different time scales, as each gives a unique insight into possible future events evident across differing periods of time.

[54] (Dr Shu Fan B.S., 2013)
[55] (Dijkstra, 2012)

Forecasting across different time scales being short, medium and large is also very important as they all depict different future demand trends, characteristics and variations of interest. Figure 26 below shows demand profiles over hourly, weekly and yearly periods respectively[56].

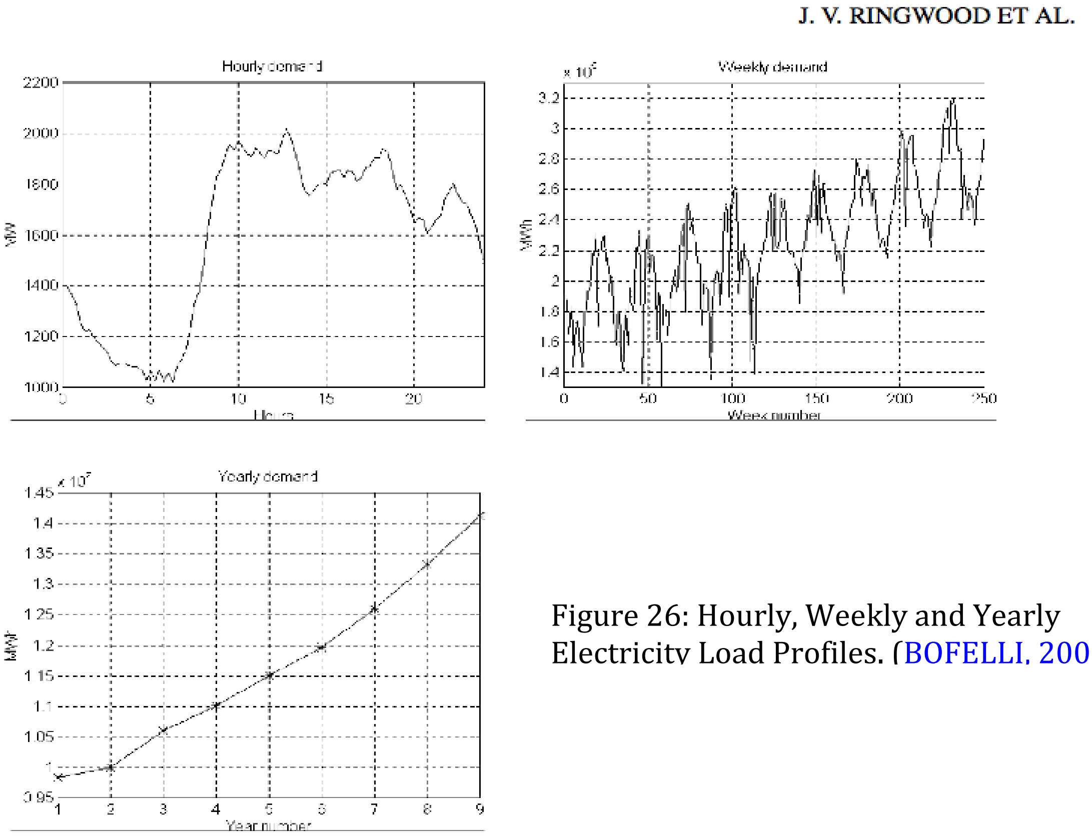


Figure 26: Hourly, Weekly and Yearly Electricity Load Profiles. (BOFELLI, 2001)

First of all the hourly profile depicts the off peak, peak and shoulder periods across the day. These changes are compensated for first, as they are the most prevalent. Second is the weekly demand. This load profile shows a period of 250 weeks and two main points of interest arise here. First of all the seasonal trends can be seen where the peaks are centered around summer and the low points winter. Second of all is the steady increase in consumption due to total demand growth. This total demand growth trend can be seen more clearly in the yearly forecast, showing quite clearly the steady rise in power consumption.

This rise is the general trend right across the world due to population growth and the ever-growing reliance upon power and especially in Australia. For example in Australia from 1990 to 2009 there was a 68% increase in the power consumed, being a total 261 TWh with a continual growth of 3% pa. From this 261 TWh a total of 78% was generated from coal, 14% from natural gas and 4.7% from hydroelectricity[57]. The statistics show how reliant Australia is upon coal to produce its electricity as opposed to most of the developed countries around the world, of which they have implemented significantly more renewable systems from energy production. In sight of the ever-growing need to electricity and the increasing use of intermittent energy production to provide

56 (BOFELLI, 2001)
57 (W. N. Association, 2012)

power into the grid, the accurate forecasting of future demand is of paramount importance to ensure grid security.

2.12.3: AMEO Forecasting

The process of which AMEO undergoes forecasting is illustrated in the figure 27 below.

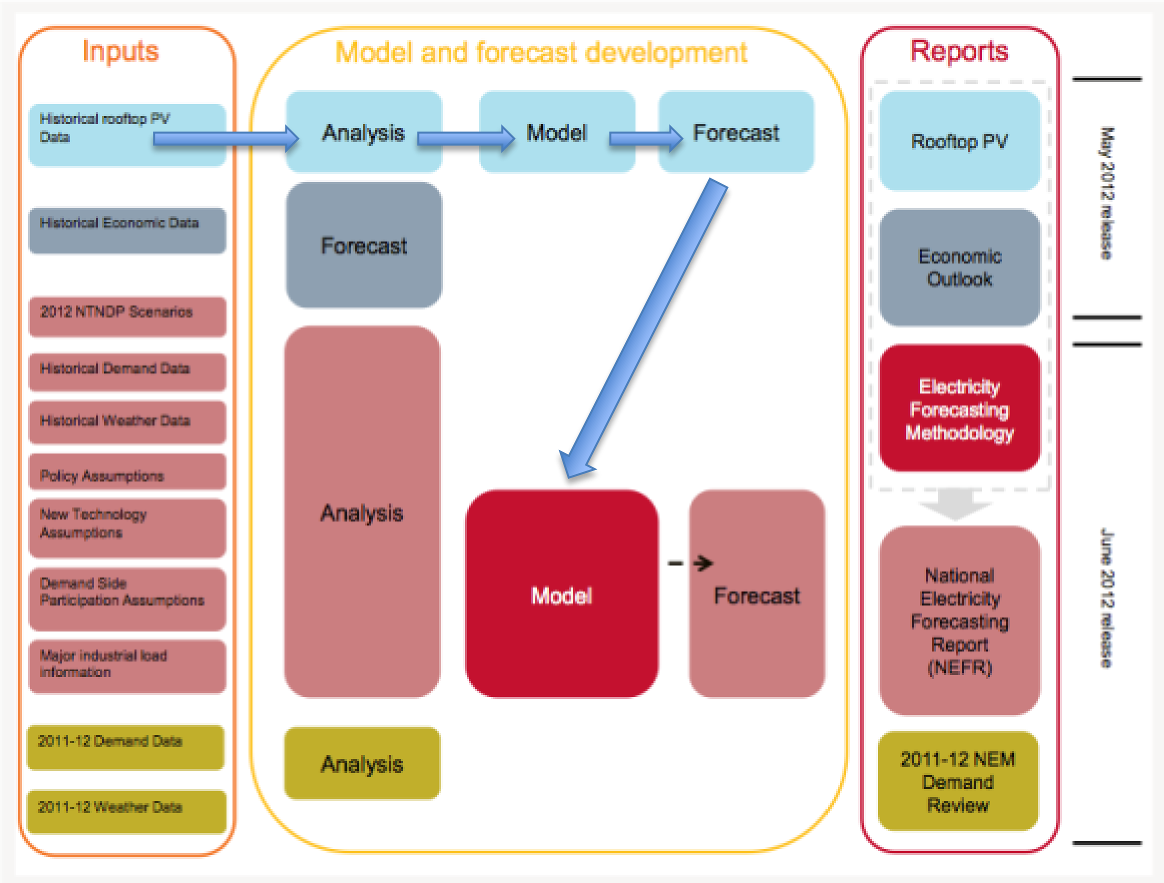


Figure 27: AMEO National Electricity Forecasting. (AEMO, 2011a)

The economic outlook information paper is produced by the National Institute of Economic and Industry Research, of which a detailed analysis of Australia's economic growth and electricity prices that is based upon economic scenarios that AEMO has defined[58]. Furthermore the forecasting methodology information paper details the modeling used by AEMO when forecasting and shows the developments made with the models, and the national electricity forecasting report is of special interest as it encumbers the electricity demand forecasts for each of the NEM regions. Finally there is the NEM demand Review paper that is simply the NEM's two-year demand outlook[59].

The rooftop PV report depicts the impact of the rooftop PV upon the electricity market as it affects generation considerably, being one of the main focuses of this report. Figure 28 shows increasing unmeasured 'behind the meter' generation that is continually growing, namely occurring from the domestic PV growth in Australia.

58 (AEMO, 2012)
59 (AEMO, 2011b)

This type of generation presents many differing problems for power utility companies, with much of this generation from many of the regions being unmeasured. This unknown and unpredictable behind the meter operations within the grid when forecasting is one of the biggest problems AEMO is currently trying to address. It is continually increasing and therefore constantly becoming more of a prevalent problem risking grid security.

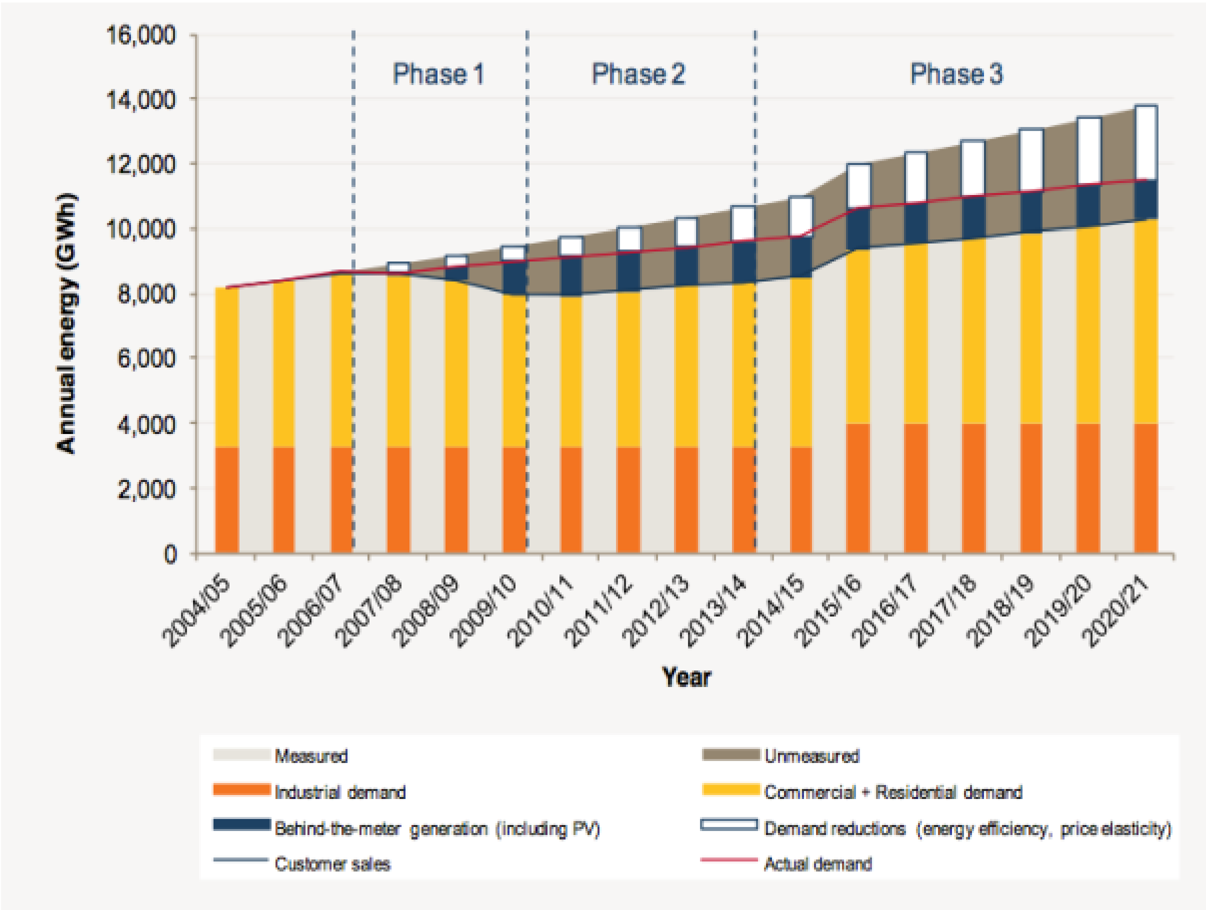


Figure 28: Example forecast showing components of demand (AEMO, 2011b)

As a result PV data is modeled and analyzed separately from the other data sets, of which then the results reinserted back in with the other data sets giving a 'master forecast'. Current demand, weather and economic factors are also analyzed separately as they also require special considerations before being used in the master forecast with the historical data sets.

Each region of the NEM is subject to different variables and assumptions at different levels of influence. Therefore AEMO has specific forecasting databases for each of these regions to accommodate for this. Each database encumbers specific regional historical, current and forecasted demographic production, income, and growth along with other variables that are used to generate economic scenarios. The National Institute of Economic and Industry Research generates the models used by AEMO. Weather data is also an input here and is taken from the Bureau of Meteorology records[60]. The variables specific to each region that are used within these models as stated in AMEO's Forecasting Methodology Information Paper 2011 are:

- Non-large industrial electricity consumption in kWh per capita
- Real gross state product (GSP) per capita in $/person
- Real state final demand (SFD) per capita in $/person
- Real average household electricity price in c/kWh
- Real average price of 'other household fuels'
- Real standard variable mortgage interest rate, % per annum.
- Heating degree days, using region-representative weather stations, daily average temperatures and region-specific change points, degree Celsius days (Bureau of Meteorology).
- Cooling degree days, using region-representative weather stations, daily average temperatures and region-specific change points, degree Celsius days (Bureau of Meteorology).
- Average air-conditioning ownership, ratio of number in regular use to total number of households.

(Taken from AEMO, 2011a)

These various historical and real-time data sets are used in conjunction with various assumptions as the inputs for the Modeling software to forecast annual energy and maximum demand predictions. Furthermore the process for calculating the annual energy and maximum demand forecasts are intertwined. This is because the annual energy forecasts make the average demand level that the half-hourly distributions are based upon.

These forecast models are also reliant upon several other sub-models and data sets to accommodate for different contributing factors. Some of the contributing elements as stated before such as rooftop PV have their own models due to their complexity and thus why are stated again here.

Elements in addition to the non-large industrial consumption models based upon regional income, energy prices and weather as stated before are as follows:

- Additional models to accommodate for power station auxiliaries (AUX) that estimate for future power station auxiliary consumption based upon future power station operation and historical data.

60 (AEMO, 2011a)

- Large industrial loads (LIL) being mostly transmission connected users on HV lines. Variations here are generally not weather sensitive, but are attributed to industrial growth or decline and predicted upon assumptions of this and public announcements.
- Rooftop PV (PV) plays another major role here as previously stated. AEMO collates data upon the installation and level of generation by rooftop PV.
- Energy Efficiency (EE). This is where users implement their own generation to supply energy inefficient processes such as induction furnaces to negate heavy grid supply costs. An average allowance of this was created for each region for the coming year[61].

This again was taken from AMEO's Forecasting Methodology Information Paper 2011.

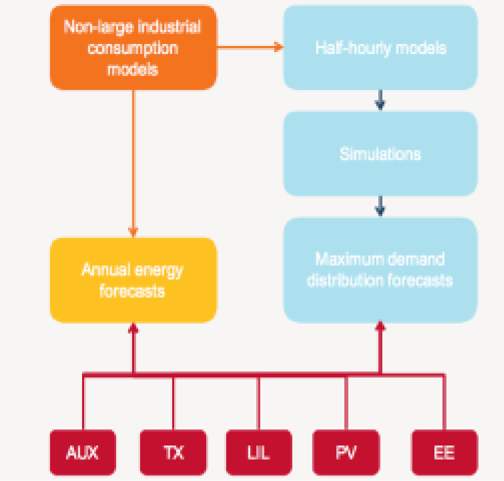


Figure 29: Forecast Process Overview. (AEMO, 2011a)

The annual energy forecasts and maximum demand distribution forecasts are then generated talking into account all of these considerations to simulate maximum demand for the winter and summer periods in Australia. The Monash University's Business and Economic Forecasting Unit create the models used here[62].

2.12.4: Generation and Demand

Demand is met by supply through the NEM's dispatch of scheduled generation in five-minute intervals, where at each interval supply is adjusted accordingly from the NEM generation pool. Demand data is then complied from this by summating each individual suppliers output within a region to give a total demand figure over a specified period of time.

Demand can also be calculated by supply metering of which returns a much more accurate demand figure. This is largely because this method automatically incorporates transmission losses, customer usage and other supply factors in the results, as it is measured at the end of the supply chain. Due to demand changing at certain points in the transmission network from losses and different customers etc, three common demand definitions are

61(AEMO, 2011a)
62 (University, 2006)

currently in practice to cater for the variations at each point. These are as generated, sent out and customer load demand. Each of these points involves additional losses and changes in the supply such as voltage and amount of regulation needed, and therefore a different demand figure returned at each point.

Furthermore understanding of the type of demand under consideration and the accumulated data used to create that demand figure both need to be acknowledged in order to create accurate forecasts. Any additional generation forms that are added to the grid in different configurations in turn can change the amount of supply needed from each. This additional supply then alters demand and therefore subsequently the demand of which is seen by AMEO (figure 28[63]). Three subset demand definition configurations of scheduled, semi-scheduled and non-scheduled demand build the three main demand configurations of which have been taken from AEMO's Nation electricity Forecasting information paper 2011(See Figure 30).

Subset definitions:

- Scheduled – Base load power stations
- Semi-Scheduled – Ancillary services such as hydroelectricity plants
- Non-Scheduled – Intermittent renewable sources such as wind farms and PV

Main definitions:

- Scheduled Demand – Purely consists of scheduled and semi-scheduled on both transmission and distribution sides. Most predictable.
- Operational Demand – Consists of Scheduled, Semi-scheduled and non-scheduled on transmission side and simply scheduled and semi-scheduled on the distributing side. Medium unpredictably due to the addition of the non-scheduled generation sources.

63 (AEMO, 2011b)

- Native Demand - Consists of Scheduled, Semi-scheduled and non-scheduled on transmission side and scheduled and semi-scheduled and non-scheduled on the distributing side. High unpredictably due to the addition of the non-scheduled generation and consumption factors.

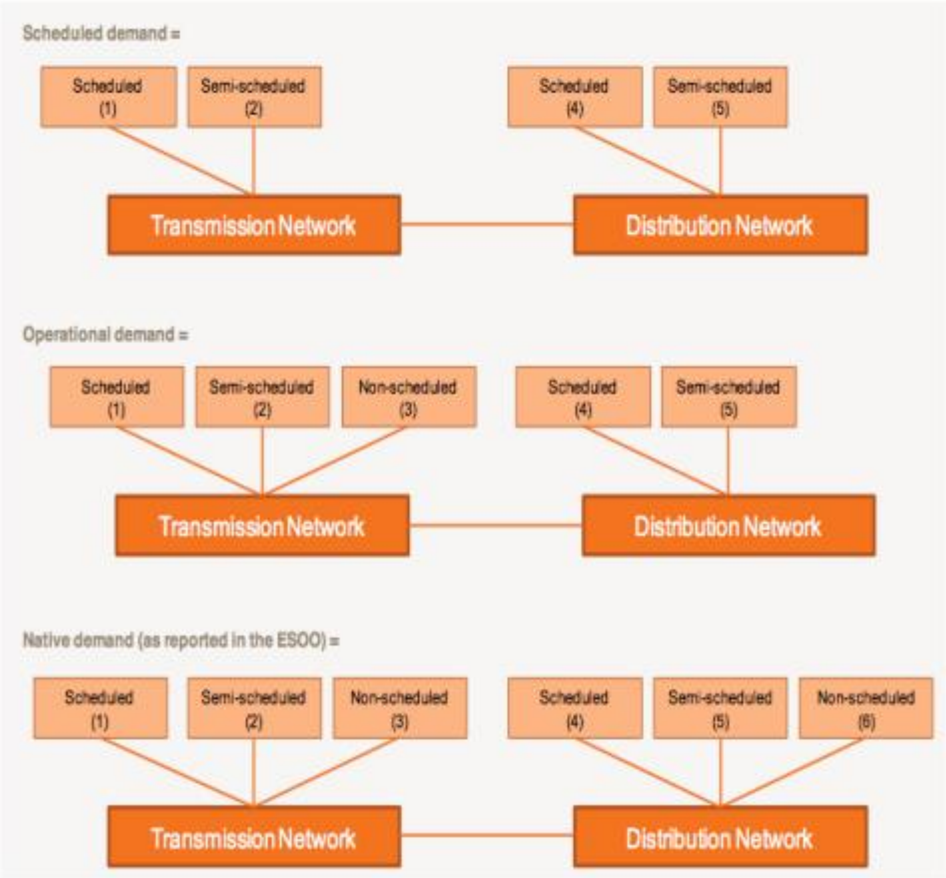


Figure 30: Demand Definitions. (AEMO, 2011b)

Furthermore rooftop PV on a generation, industrial or residential level is a huge element when determining demand. This factor creates one of the biggest gaps in the data currently, as these users are fulfilling their own demand on the distribution side where in most regions it is unmetered[64]. This problem needs to be solved so that the demand forecasting can remain accurate, and grid security maintained with the ever-increasing rooftop PV systems. This is one reason that has contributed to the addition of the different demand configurations as stated in figure.

Industrial demand is accounted for separately from domestic supply. This is due to it generally being the largest consumer, with much larger individual loads and differing daily demand profiles and therefore has the most potential to alter the forecasts. The catalysts for the variations in demand for the industrial sector also differ from that of the civilian market. Thus if the industrial load forecasts where combined with the civilian forecasts the results would drastically off, as the assumptions made and the drivers for variations in load here are very different to the civilian market. Furthermore there is behind the meter generation here again in the form of rooftop PV and possibly diesel generators. Diesel generators are widely used in

64 (AEMO, 2011b)

industrial workplaces to supply load to systems like that of induction furnaces, of which impart a large inductive load upon the grid. The diesel generators are utilised here as supplying power to such equipment through the grid is exceedingly expensive, with the much more cost effective power source arising in the form of diesel. This has to be considered for the industrial sectors of the market also as it again alters demand[65].

[65] (AEMO, 2011b)

Chapter 3 - Methodology and Research

3.1: Introduction

To ascertain if the proposed PHES system between Cressbrook and Perseverance Dam is not only economically viable but will also be an effective asset within the NEM; HOMER Energy software will be used in conjunction with a spreadsheet model. HOMER will be used to model a portion of the proposed pumped hydro system to determine net energy output with different pumping and supply configurations. Other changing factors will also be taken into account here being mainly environmental considerations such as solar exposure. Results then will be generated for all different system configurations to find the optimal setup; of which includes both grid connected and standalone configurations for the pumping system. Additionally multiple different system sizes will also be tested to ascertain the optimal system arrangement with cost being of main concern without compromising functionality. Such considerations here are the converter size for the PV system, the VRB-ESS, the PV net capacity and etcetera.

It should be noted that there are a lot of unknown variables here and many elements that are in a constant state of flux of which comes naturally to the energy grid. This ever increases complexity and variability, and within such a chaotic system the most that can be done to mitigate these effects is to increase adaptability, capability and overdesign the system so that every possible contingency event is considered.

Additionally finding current Australian relevant figures for the pricing of equipment along with other economic considerations that have to be made is very difficult, as projects of this scale are usually tendered for. Many figures will have to be estimated and therefore the modeling output in this regards will not be totally accurate, and therefore should only be used to give a basic overall awareness when considering the economic factors within in this project.

3.2: Methodology

3.2.1: Costs

3.2.1.1: Infrastructure and Equipment Cost

The total initial capital of the Hydro plant would equate to approximately 250 million with a 40 year life time having O&M costs of 1.5% of the initial investment[66]. Furthermore an annual charge for the switching station and transmission line assets and connection costs would amount to approximately $3,500,000 with an unconditional Bank guarantee of $13,200,000.

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66 (I. I. R. E. Agency, 2012)

PV is approximately $2.9 cents per watt installed[67] or approximately 12 cents per kW/hr[68]. Therefore the solar system within this project would cost approximately $58,000,000. This is in reference to a previous solar power project that was undertaken in Royalla New South Wales. This particular project was selected as it has an installed capacity of 20 MW and was undertaken in 2013, being very similar to the project proposed here. The Royalla PV farm was quoted to cost approximately $2.90 dollars per watt of capacity[69], and therefore this will be the quoted figure of choice for the PV system in this project.

The wind element's initial capital cost was appraised to be in the order of $1800 per kW of installed capacity. This figure is largely subject to change as the initial capital of such wind generation system is set to decline over the coming years, with the price also varying somewhat between each manufacturer[70].

VRB battery system was appraised to cost approximately 426 $/kW and 100$/kWh [71]. However due to this technology being only relatively new, this initial calculation should be considered with the expectation that it could possibly vary heavily.

Additionally a large scale inverter system will also be needed to bridge the PV system to the pumping system. A worst case assumption was taken here where the inverter cost was approximated to $0.18 per watt[72].

3.2.1.2: Operation and maintenance costs

The maintenance and operation cost of the various equipment associated with this project amounts to approximately $10,000,000 dollars per year ($9,914,538 as calculated by HOMER). Therefore over the 40 year life span of this project the total O&M cost equates to a projected $147,395,440, with the main bulk of this cost being incurred from the grid connection making up over 55 percent of this cost.

3.2.1.2.1: Hydropower plant O&M Costs

Operation and maintenance costs of hydropower plant are within the area of 1.5% to 2.5% of the initial investment which is the current global average[73]. Thus the hydro plant system is likely to incur of its operational lifetime O&M costs of approximately $57,000,000.

67 (Martin, 2013)
68 (Wood., 2013)
69 (Martin, 2013)
70 (Patrick Hearps, 2011)
71 (Dumancic, 2011)
72 (IHS, 2013)
73 (I. I. R. E. Agency, 2012)

3.2.1.2.2: PV O&M Costs

Then the operation and maintenance cost per year had to be determined for it to be factored into the modeling. This data was ascertained by the National Renewable Energy Laboratory (NREL), with the operations and maintenance cost for the PV plant being chosen to approximately be $35 per kW of installed capacity per year[74] worst case. Therefore total yearly operations and maintenance costs for the solar panels equates to approximately $700,000 per year for a 20MW plant.

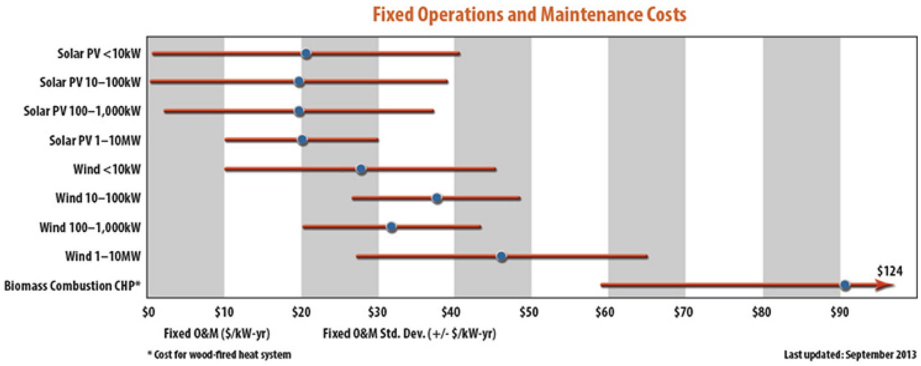

Figure 31: PV Operation and Maintenance Cost. (NREL, 2013)

3.2.1.2.3: VRB-ESS O&M Costs

The operation and maintenance cost for the vanadium redox battery (VRB) system is relatively low being approximately 50$/kW per year of operation[75]. Therefore a 1MW system would cost $50,000 per year to maintain.

	Source:	Schoenung 2003 [5]	EPRI 2003 [2]	Gonzalez 2004 [3]	Schoenung 2008 [6]	Chen 2009 [7]
Techno. Params.	Roundtrip Efficiency [%]	70	60-75	67-81	-	75-85
	Self-discharge [%Energy per day]	0.2	-	-	-	small
	Cycle Lifetime [cycles]	-	14000	-	-	12k+
	Expected Lifetime [Years]	10	10-15	10	-	5-10
	Specific Energy [Wh/kg]	-	-	-	-	10-30
	Specific Power [W/kg]	-	-	-	-	-
	Energy Density [Wh/L]	-	-	-	-	16-33
	Power Density [W/L]	-	-	-	-	-
Costs	Power Cost [$/kW]	210	-	-	175	600-1500
	Energy Cost [$/kWh]	710	-	200-220	350	150-1000
	PCS Cost [$/kW]	120-600	370-610	270-580	-	-
	BOP Cost [$/kW]	36	120	-	30	-
	O&M Fixed Cost [$/kW-y]	24	33-65	-	-	-

Figure 32: VRB-ESS Specifications (Bradbury, 2012)

3.2.1.2.4: Wind Farm O&M Costs

The yearly operation and maintenance cost of wind turbines is generally higher than that of other renewable stationary systems. This is due to the wind turbines having many moving parts and rotating systems that require constant maintenance, as such moving components wear much faster than stationary systems. Thus the yearly operation and maintenance cost for the wind system is in the order of $40 per kW per year[76].

3.2.2: Solar System

74 (NREL, 2013)
75 (Bradbury, 2012)
76 (Milborrow, 2013)

Historical monthly mean daily solar exposure data was taken for Cressbrook dam to be used as the data input for the PV system in HOMER. Year 2013 was used as it is the most relevant and complete data set available.

Number: 40808 Opened: 1990 Now: Open Lat: 27.26° S Lon: 152.20° E Elevation: 295 m[77]

The data was provided in MJ/m^-2 and therefore had to be converted to KWh/m^2 to match HOMER's requirements.

Again other considerations will be taken here also within the model, along with varying system sizes to be considered to ascertain the best and most cost-effective solution.

HOMER energy is unable to model a PHES system where the PV and grid provide power to the pumps when the system is in pumping mode. HOMER only contains a conventional hydro-generation system of which the system only generates electricity from a changing head, and cannot operate in any other manner. Because of this the complete system will have to be broken down into its rudimentary subsystems, after of which then will be intrinsically joined back together.

Therefore the output of the PV will be supplying a generic load in substitute, to yield a net potential useable power for pumping. The pumping cycle was very difficult to model due to homer being unable to simply use all PV power generated to pump when the power is apparent (Dynamic in nature). Furthermore a particular system configuration needs to be grid connected if additional pumping is required, then off peak power would be ideal to do so. However presently this is also not an option as bulk tariff that is used within this project does not cater for this, of which has fixed rates[78].

Depending on system configuration the total useful power generated by the PV will be used to determine how much bulk water can be shifted from the lower catchment to the upper catchment with the available resources. This was a major challenge trying to make a dynamic system, where all PV power is utilised with then the grid just supplementing any shortfalls. If the PV proves insufficient to fulfill the load then the amount of grid power needed to compensate will have to be determined. Cost again is the major factor here and will play a major role as to what will ultimately prove to be most viable option. Furthermore the PHES pumping system will be grid connected for pumping regardless if the power generated from the PV sufficient or not, as this will provide a strong level of security for the system and increase usability. This will also allow the PHES system to act in synchronous condenser mode if or whenever necessary.

[77] (Commonwealth of Australia 2014)
[78] (Dr Malcolm Roberts, 2014)

3.2.3: Possible Wind Farm

An additional renewable element being a small scale wind farm alongside the PV was also considered in the modeling. Varying numbers of small 250 kW turbines where considered with HOMER then outputting two optimal results, one set of which incorporates the wind farm and one that does not. The two optimal results where compared against each other under the same set of base operating parameters and sensitivity results, with the most beneficial option being taken.

This became tricky however as many of the results yielded outputs very close to each other, and therefore additional consideration had to be taken when the decision was made as to which was the most optimal system. For example if the result that incorporated the wind element was more expensive, but only marginally this system may be chosen. This is because the cost of wind farms, like that of PV is decreasing with time as the technology becomes more refined and easier to produce etc., and therefore could possibly be more cost effective over time. This is in addition to the fact that now more renewable power is now being created and used within the system instead of gird power, making the whole project a greener and more environmentally sustainable solution.

3.2.4: HOMER Model

First of all each component of the HOMER was added into the simulation with their variables set as quoted and required. Infrastructure, equipment and commodities where set (see section 3.2.1) along with all other associated overheads and equipment sizing, along with the daily demands according to each simulation variant.

The model created in HOMER will have to be modified for each specific scenario within the Excel model. For the scenarios that incorporate the renewable PV system, the data will have to be modeled in HOMER first so that the outputted data can then be used within the Excel model. This is primarily due to then many changing factors that are now imposed upon the system of which HOMER simulates on an hourly basis, mainly surrounding the PV and wind elements. Changes in the monthly maximum demand and monthly energy required will both occur as the PV (and possibly wind farm) are now fulfilling a portion of the demand, and as a result the Excel model will have to be dynamic to compensate for this. The percentage of demand fulfillment will be subject to change on a daily basis due to many environmental factors, and therefore a more extensive model is necessary.

Each major scenario varies in days operational and therefore all need to be modeled separately in HOMER, with each having a specific demand profile. The scenarios chosen were 240, 96, 48, 24 and 12 days active over the period of one year. This method was undertaken to ascertain how each individual scenario differs from one another, and to ultimately find the optimal running time per year.

In addition to the pump demand profile, the possibility of a weather event occurring also had to be considered here in the form of another load. A specific demand profile again had to be generated for this (see section 3.2.5.2).

A battery bank in addition to all the other equipment had to be considered for the intended system also as previously discussed, being a contingency measure to the possible weather event that effectively drops the PV output power. The VRB (Vanadium redox battery) system was decided to be used here as it is currently the most suitable arrangement within HOMER for such a large scale application, and it is also being currently tested worldwide for similar purposes.

It should be noted that whilst weather events cause dramatic output changes in small scale solar systems, for large scale arrays in the megawatt regions the output variations aren't as significant. This simply is a result of the sheer scale of the large PV plants. As more space is required for the panels in additional to the increased output capacity, smaller cloud systems do not have such an affect. However with the increase in PV size, arises the increasing risk with large and severe weather fronts. This is due to the now higher possible PV to grid load shift under such circumstances, if a weather system was to cover a large enough portion of the PV area[79].

3.2.4.1: Daily System Load Requirements

For a 100MW plant approximately 2,400 ML is required for a 12 hour pumping cycle, with the dam anticipated to be in the order of 5/6 gigalitres. Therefore if 12 hours is taken as a reference point for the pump/generation cycle, 200 ML per hour has to be pumped daily to break even.

Therefore a 12 hour pumping rotation is not viable. This is ok however as the proposed PHES system is not envisioned for such a 12 hour cycle, but to be a fast acting relief generation source for SEQ in the instances when the grid connected solar generation capacity rapidly drops. Also this system is aimed at relieving the stress upon the NEM that the utility and civil grid connected PV systems are imposing on it on a daily basis, being the increasingly rapid fluctuation from shoulder to peak period time as previously discussed. The changeover from the shoulder demand period to peak demand period historically is much more of a gradual transition as opposed to the contemporary rapid change over, and thus the pre-existing conventional systems where not designed with this in respect. Therefore this system is aimed at ultimately reduceing the severity of this change to give more time for the bulk energy producers to increase their throughput.

With this in consideration the projected PHES system at bare minimum will only require approximately 200 – 400 ML of head above the minimum operating level, providing between one to two hours of generation time. This is ample capacity as the bulk utility producers need this amount of time to ramp up their generation to ultimately takeover, of which being the intended function of this station. However maintaining a generation

[79] (Barber, 2011)

capacity that is out to six or seven hours, which is quite possible would be of great benefit and would return much higher profits. This then would easily allow for the part negation of the rapid demand changes that are occurring while also maintaining the extra capacity to generate additional power. This would return additional profits as this excess head and therefore power could effectively be time-shifted to the peak period, thus yielding the highest return prices for the sale of electricity. This option is much more viable if the system isn't required as often throughout the year, and therefore as a result the electricity generated by the PV alone would be sufficient for pumping negating the need for any grid power.

With the intended 20 MW PV system (and wind farm possibility) as the main generation source for the pumps, the pump ratings with all things considered should consume approximately 14MW per hour. Such factors that needed to be accounted for here were mainly daily solar intensity and system losses.

Finally the system from initial calculations would approximately pump 17ML per hour, over a 12 hour pumping period to shift a total of 204ML. This was calculated with the formula below:

Power (Ph)

$$Ph = q \rho g h / (3.6106)$$

q = flow capacity (m^3/hr)

p = density of fluid (kg/m^3)

g = acceleration due to gravity (9.81 m/s^2)

h = differential head (m)

Then to take into account pump efficiency:

Shaft power (Ps)

$$Ps = Ph/n$$

n = Pump efficiency[80]

Being a generator operating within the peak and shoulder demand markets many factors affect operations daily and can occur rapidly. Thus this total will be heavily subject to change and the chosen pumping duration was only used as a reference point. Many factors dictate how much pumping will have to be taken place on a daily basis as solar intensity therefore PV output changes daily, along with the demand (generation) required from the system. Again also the amount of pre-existing water stored in the catchment is another element that greatly dictates pumping levels.

80 ("Pump Power Calculations," n/a)

3.2.5: Model Loads

3.2.5.1: *Pump loading*

The number of days pumping is required varied from 240 to 12 days per year as stated before (see section 3.2.4) to see how operations vary with level of utilization. Additionally for the scenarios that incorporated the pumping profiles of the lesser days utilized, the days active where mainly focused around the beginning and the end of the year. This was done intentionally mainly due to the seasonal trends, with the seasons around this time being spring and summer. Over this period the solar exposure historically more intense along with more intense and occurring weather systems (See figure 33). As a result the PV will be most effective during this period, with also the increase in likelihood of weather systems hemming the PV generated electricity being the most opportune time for the PHES system to operate. Thus is why this approach was taken.

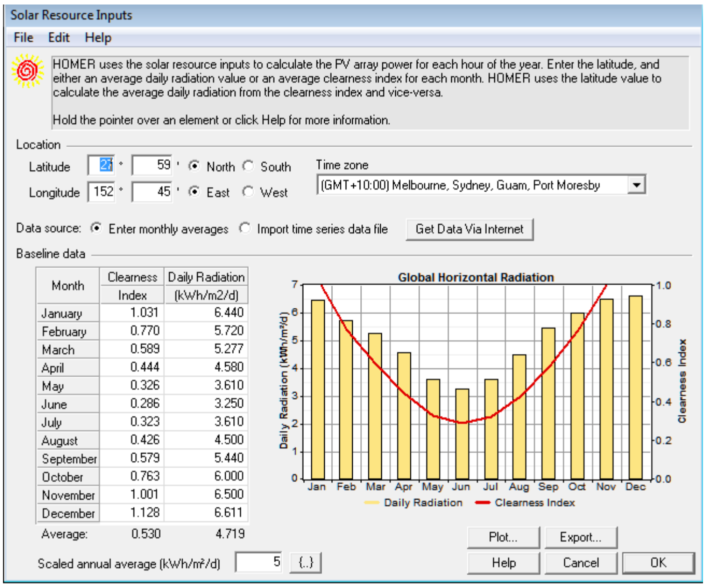

Figure 33: Yearly solar radiation for Cressbrook Dam area (Commonwealth of Australia 2014)

Challenges arose for the pumping model when a pumping regime was trying to be set. This is because HOMER operates by a static set of data inputs with a set random daily variability. This is not ideal for the intended system as the level of generation needed can vary greatly on a daily basis from zero to full utilization depending upon demand and environmental factors across SEQ. Also the amount of pre-existing head has to be considered also as its constantly in flux due to not only the pumping and generation cycles, but also if additional bulk water needs to be supplied to Perseverance dam for urban and commercial use. However to account for the pre-existing head, the output generation model is needed which requires the pumping model. This feedback problem needed to be addressed here.

3.2.5.2: *Possible weather loading*

An additional DC load was inserted into the HOMER model along with the regular pump load. This DC load is to simulate if a weather event was to occur such as a storm or cloud cover, which would effectively reduce the

PV output drastically in a short time period. This problem is the same as that of which this system is trying to somewhat alleviate for SEQ.

Due to this additional 'weather' load, a battery element was also inserted as a contingency to the weather occurrence as stated previously. This contingency measure was taken as precaution because this system imparts a large demand on the grid, in addition to having a large renewable fraction. For example if the PV array is operating at approximately 15 MW and then was to be halved in the matter of 10 minutes, this additional load of 7.5 MW would then have to be rapidly transferred to the grid. This spike in demand upon the SEQ electricity grid would cause many of the problems that this very system is trying to null, where its operation then would be doing more harm than good to grid security. Thus a battery system is necessary to attenuate this effect if such instances where to occur, where the transfer of system demand from the declining PV power onto the grid could effectively be made more gradual with the batteries now imparting power here. This would reduce the demand fluctuation severity seen by the grid drastically in such events, being highly beneficial to all parties and further reduces the possible detrimental footprint such a system can have.

3.2.5.3: Demand Schedules

Each demand schedule was custom generated so that a specific daily pumping and weather loading regime could be specified, and therefore readily modified if need be depending on each model variant. The load profile was generated in Microsoft excel of which then copied into notepad to change the format in order to be compatible with HOMER.

3.2.5.4: Operating Reserve

HOMER also caters for an operating reserve within the calculations in two ways, as a percentage of total load and as a percentage of renewable output. This was utilised to create a sufficient reserve power margin to act as a buffer within normal operations if an unforeseen contingency event that required additional power occurred whilst the system is operational. This is carried out as a safety measure if any unforeseen event was to occur and is common practice within such systems. Without such a reserve the intended system could again possibly be under a variety of contingency events, highly detrimental to the local and possibly national grid.

A 10 percent operating reserve as a percentage of total hourly load was chosen in additional with a 25 percent operating reserve as a percentage of renewable output. The renewable reserve was set considerably higher due to the constant high and fast variations in solar intensity.

3.2.6: Base PV model

The PV element of this project was added primarily to reduce the demand cost that is within the current tariff, as this cost exceeds the energy charge fee if the system is utilised only on rare occasions which would likely be the case. However this also proved to be a problem within the preliminary results.

It was discovered that to reduce cost of demand pumping had to be carried out over a longer period of time at a lower rate. This resulted in the PV being of lesser benefit as there were insufficient sunlight hours to accommodate for the total of the pumping duration, where the PV had no effect on the overall demand cost. Also this PV output inadequacy was especially protonate within the winter period as the solar intensity and number of daylight hours both are significantly less than that of the summer period. Therefore the cost of demand will remain constant to the load without the PV having any affect upon it if such long pumping durations are chosen. Furthermore if the pumping duration is decreased to coincide with that of the effective PV generating hours, system demand will have to be drastically increased once again. Doing this is somewhat counterintuitive as the increase in demand that would allow the PV system to effectively reduce it somewhat over the entire pumping duration, would possibly only bring the demand level back down to the previous 'long duration' level if not higher.

For the PV to have any affect in reducing the demand cost the pumping will have to take place at the very minimum between 8am and 4pm. This allows for only a eight hour window and therefore the pumps will have to be operating at 33.75MW to allow adequate water to be shifted within this time, and can be seen in figure 34.

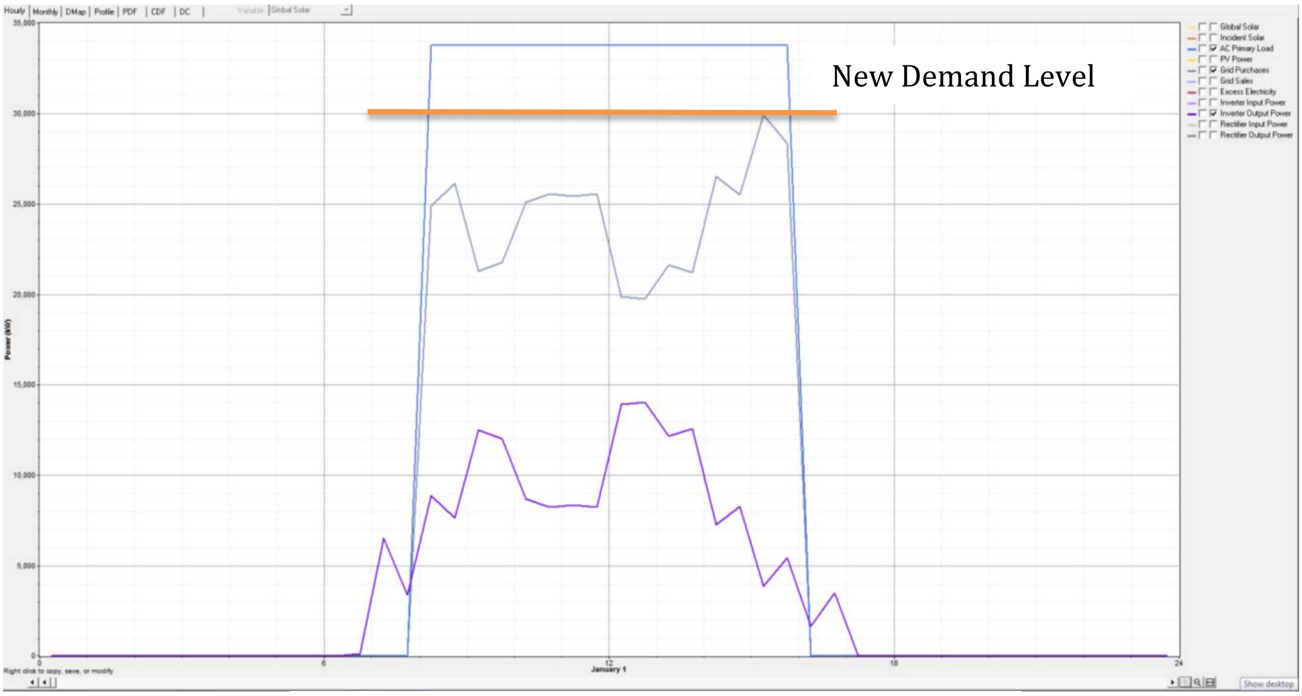

Figure 34: 24hr pumping load profile in summer months with PV system to reduce demand.

The blue line in figure 34 is the demand profile of the pumps over a one day eight hour cycle at 33.75 MW. The purple denotes the output of the converter system from the PV and was chosen as this is the resultant useable power from the solar system after all system losses. Then finally the gray line depicts the total grid purchases over the day to make up the shortfall between the load and power supplied by the PV. With this regime the maximum demand is still is approximately around 30 MW reinforcing the statement previously made, where a medium between both ideologies has to be found.

Furthermore the above graph was taken from the first of January being summer in Queensland and therefore the days yield long hours and high solar exposure. Over the winter months there would again be even less time and generation capacity for the PV to be effective. The best option here is possibly to use a shorter and more intensive pumping regime though the summer months to utilise the full capacity of the PV, then throughout the winter months a longer and less intensive regime should be used as the PV is nowhere near as effective or reliable. This would bring the overall demand level back down whilst still maintaining adequate hydro-generation capacity. A 20 hour pumping cycle at 13.5MW load would be more adequate for the winter months due to these factors. This load profile can be seen below in figure 35.

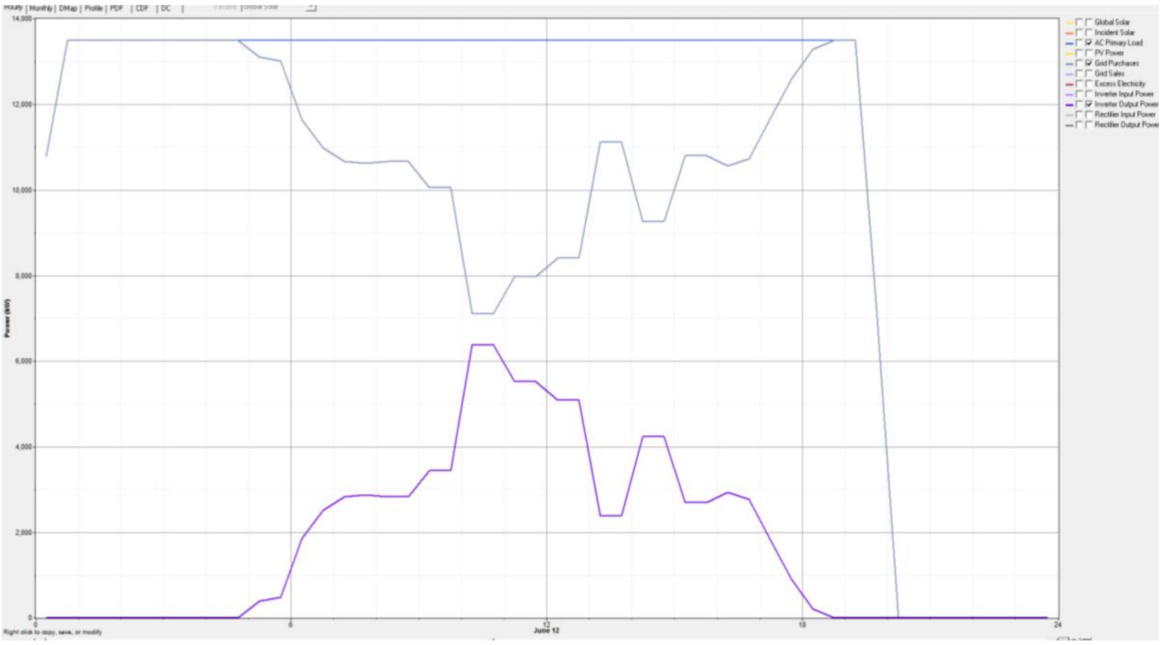

Figure 35: 24hr pumping load profile for winter months with PV system to reduce demand

3.2.6.1: Electricity Rates

Tariff 44[81] as per the Queensland Government Gazette was used throughout all the HOMER models as the standard for the purchasing of electricity for this system. The cost of electricity per kWh was set at $0.132 with the demand rate at 38.514$/kW/mo.

Then an additional independent sellback rate was input alongside the purchasing rate. This rate involved no purchasing price or demand rate, only a sellback rate. This was because the sole function of this rate is for the sale of the stored potential contained within the PHES system. This rate comes into effect in-between the

81 (Dr Malcolm Roberts, 2014)

periods of 7-8 am and 4-7 pm because these times are the peak retail periods (See figure 36). Furthermore several sensitivities where run on the sellback rate for these periods ranging from a minimum of $.132/kWh being the standard electricity tariff price and $.34/kWh which is currently the average peak price in Queensland. Additional sensitivities were also run between these prices with $.6/kWh being the maximum. This was chosen due to some states are currently reaching around these prices during peak times such as South Australia[82]. This approach was taken to generate best and worst case scenario results, with the main aim being of trying to find a break-even point between the cost of the system to the sale price of electricity.

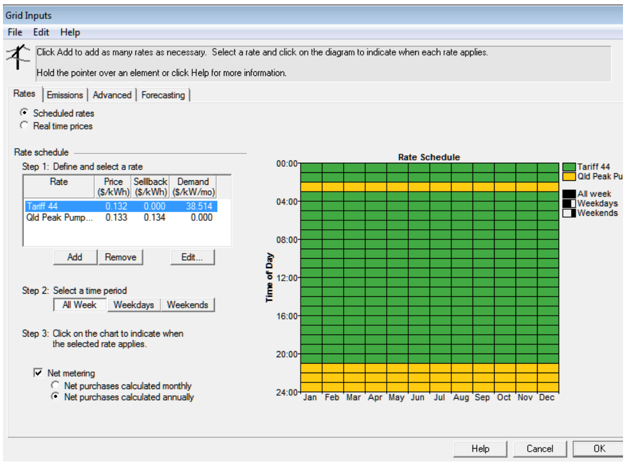

Figure 36: HOMER Rate Schedule

Power will only be sold during the peak sellback periods from the pumped hydro system, with the remainder of the time being used for pumping if necessary. If there is an excess of renewable energy it will be stored i.e. used for pumping even when pumping isn't required. If the dam capacity is reached only then will the renewable power be sold outside of the peak sellback period.

The HOMER model's mode of operation however had to be altered for it to operate effectively. The sell back periods had to be outside of the real-world times as stated above as these times gave rise to possible conflictions within the data. The potential problem arose where the trading of power was bordering on the pumping period. This was a problem due to HOMER's limitations where alternate 'round-about' methods had to be taken to achieve a feasible result, being the utilization of a VRB-ESS to act as the PHES system.

Additionally it should be noted that depending on day's utilized per year, the rate schedule will change accordingly. For example the 270 days per year utilization model will include a rate schedule as seen in figure 36 as pumping occurs across each month of the year. However for the lesser days utilised such as the 12 day operation scheme, pumping only occurs within 3 months of the year and thus the rate schedule will only allow the sale of power across these three months. This will occur for each yearly pumping profile, where the number of months pumping occurs will be the same for the number of months that are available for the trade of power.

82 (AEMO, 2014c)

Furthermore a similar approach also was taken for the one day cost of the system. The one day cost of each day's operational variant did not follow the number of days pumping, however the number of days in each month active was used to calculate this. For example the 12 day variant occurred over three separate months, and therefore power sales to the grid did only occur for 12 days but rather 93 days being the figure used to calculate the one day cost. This approach was adopted for each scenario.

- 270 days pumping = 365 active sellback days
- 96 days pumping = 306 active sellback days
- 48 days pumping = 215 active sellback days
- 24 days pumping = 154 active sellback days
- 12 days pumping = 93 active sellback days

3.2.6.2: VRB-ESS System Acting as PHES

Within the HOMER model a VRB-ESS system had to be used to act as the storage component of the pumped hydro as HOMER does not incorporate a conventional hydro-storage system within its software package. Additionally the VRB-ESS component acting as the hydro-storage does not incorporate any costs within it. This is due to the initial capital and operation and maintenance costs of the PHES system was all taken into consideration within the economics tab, being pre-set constant values.

A 100MW hydro plant approximately requires 200 ML for one hour of operation. With the anticipated dam to be in the order of 6 gigalitres, this volume will retain approximately 30 hours of generation time. As a result this equates to 3000 MWhr of storage capacity, and was initially figure used within the HOMER model for the VRB-ESS 'Hydro Storage' system rated at 100MW.

However this was not viable within the HOMER model due to its limitations. The VRB-ESS had to be made to have infinite capacity, of which it was scheduled to only provide power during the periods of when the sellback rate was at peak. Meaning its sole function was to provide power to sell, and not to operate for another reason. This is a justifiable cause of action as the Daily pump demand was added into HOMER as an additional load, of which being theoretically the VRB-ESS 'pumped hydro' energy source. Additionally the hydro VRB-ESS initial state is full capacity, not being ideal as the hydro storage system will not have any bulk water stored initially and electrical resources will be required on start to build the bulk water capacity. Again however this didn't prove to be a problem as the daily demand accounted for this, with the demand having to be satisfied in parallel with the sale of power. For example when pumping demand is satisfied, this in theory provides the storage potential for the already at capacity hydro VRB-ESS of which will never require any power.

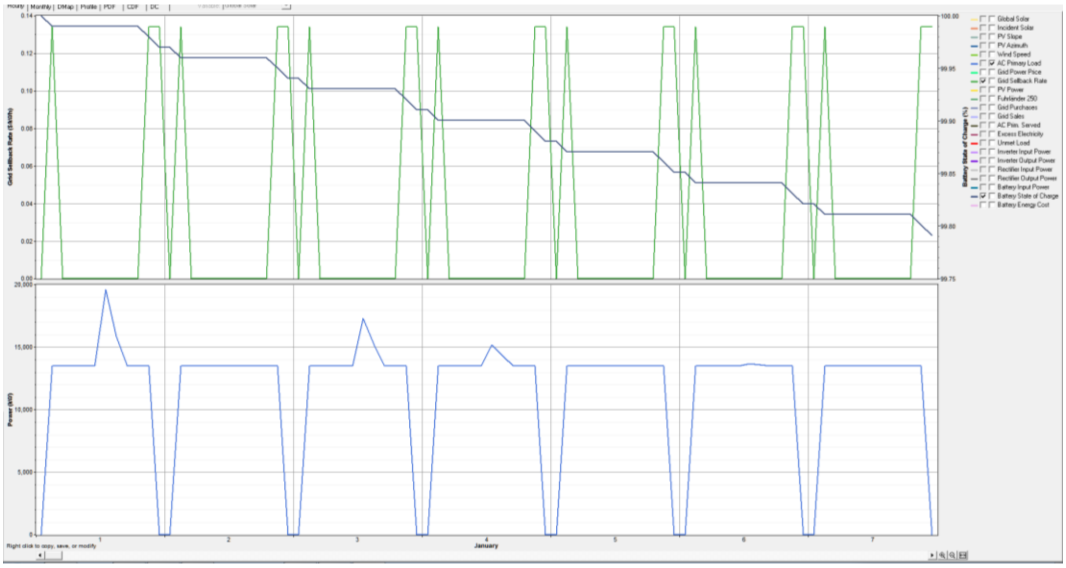

Figure 37: 'Hydro' VRB-ESS state of charge

The pumping and sale regime can be seen in figure 37, where the battery is only designed to discharge over the sale periods, with the load being purely satisfied by the renewable and grid elements. This is hardly ideal, however due to HOMER and its mode of operation this solution was believed the best.

3.2.7: Future Viability Model

Currently the feasibility and practicality of this project is out of the realms of possibility. The cost involved in the form of electricity required to operate alone is the major deterring factor here, as the demand charge that would be incurred for such interment and rarely used equipment is substantial. An 8 hour pumping cycle running at 33.75 MW for example would incur costs up to approximately 1.3 million dollars regardless of demand time over the corresponding month, and if such a system is utilized only once or even only several times in the month such costs are unsustainable. In addition to this cost there are also energy consumption costs with the addition of operation and capital expenses involved, increasing the levelised cost of electricity (LCOE) for this system. Initial calculations estimate within the first year of operation the initial capital of this project could reach over $280,000,000, with a yearly operating cost of approximately $10,000,000. Therefore the proposed infrastructure in the current climate is simply not possible; however if current energy and technology trends are taken into consideration such a project will become increasingly viable and profitable as time passes.

As the price of electricity becomes increasingly expensive with solar panel technology and VRB-ESS systems continually becoming more cost effective and efficient, a point in time will come where this project will be viable with a large installed PV plant. Furthermore as this time approaches such ancillary services will become increasingly necessary to maintain grid security, adding again to this systems appeal.

This possible future viability point was approximated by using trending electricity and PV data within the HOMER model. Several iterations where run in parallel with differing electricity costs and installed PV costs as per the contemporary trending data to try and ascertain an intersection point where the installed PV is more cost effective the running the system of grid power. It should be noted that the LCOE was used for both the grid power price and PV power price as this takes into account all costs involved for each commodity of the entire life time of the project.

However a problem arose here with the pumping duration and total hours of useable solar exposure for the PV system. The time pumping within the modeled system exceeds the number of daylight hours available for use by the PV making the system, regardless of PV/grid parity of not reliant upon the system to a certain extent. This can be overcome if PV and storage systems such as VRB-ESS become cheap enough that a large enough capacity can be installed of both systems to compensate. Another possible solution here lies within the theory behind the full PV utilization model, where all power generated by the PV system is used for pumping when available. This is a good solution if the system is utilized only on occasion throughout the year of which it is intended to be.

However if the system is utilised for more consecutive days (such as the 270 day use model) over the year this will put additional stress upon the PV and battery systems. Their yearly yield would then have to increase to serve the additional load, of which may entail in increasing the systems size further or becoming reliant upon the grid for a certain percentage of the load. Again this scenario of increasing the renewable capacity within the project to an amount to make it a standalone system is highly unlikely, where the costs of each commodity would have to change considerably to be viable.

3.2.7.1: Sensitivity Inputs

To model for future viability taking into account the relevant current market trends (see section 2.6), several sensitivity iterations had to be run in conjunction with the base models. These subsidiary inputs where run in parallel with the base model to verify exactly how each one impacts the overall result of the system. Each sensitivity input was changed purposely to see just how the changing PV and energy markets would affect the systems operation in output and demand, along with each of the costs associated with it. Another aim here was also to try and extrapolate the data and current trends to potentially find a point in time where this system would be financially viable and effectively yield a return. Additionally each sensitivity input can be used totally independent of each other aiding usability.

The HOMER sensitivity model inputs are as follows:

Sensitivity Analysis	Baseline	Energy variant 1	Energy variant 2	PV variant 1	PV variant 2	PV variant 3	PV/Energy variant 1	PV/Energy variant 2	Optimal Variant
PV Capital Multiplier (X original)	1	1	1	0.9	0.8	0.7	0.9	0.8	0.7
Wind Farm Capital Multiplier (X original)	1	1	1	.9	.8	.7	.9	.8	.7
Tariff 44 Demand Rate ($/kW/me.)	38.5	50	0	38.5	38.5	38.5	50	50	0

The above sensitivities will be run in parallel with the baseline sellback rate sensitivities as per the base model. Also the PV capital multiplier, wind farm capital multiplier and converter capital multiplier where all linked together to speed up processing. This is viable as these sensitivities did not need to be run separately from one another, all of which being interrelated.

Additionally a variation in the power price could not be modeled within the sensitivity study as the systems configuration did not allow for it to be changed. This was because the 'hydro-storage' VRB-ESS would not function as intended if this value was altered as the operation periods of this component needed to be within strict guidelines. It was prohibited to operate below the power price of $0.133/kWh, which effectively only allowed this system to discharge in the periods where the peak sellback rate occurred. This was done to prevent the 'hydro' VRB supplying energy to any loads local to the system.

3.2.7.2: Data Extrapolation for Future Viability

The process of extrapolating the data from the sensitivity results was relativity easy due to HOMER being largely an optimization software package. Multiple PV sizes to consider where entered into HOMER, ranging from 0kW to a 20 MW system in 500kW steps. The model was run with HOMER returning the most optimal PV size for the base model. Then as the sensitivities where changed the most optimal PV size varied with them, with the PV size slowly increasing as it became a more viable solution. Finally the point at which the system would achieve maximum viability within this study would be when the sensitivity results are all pushed to a point where the most optimal system returns a PV capacity of 20MW.

Then the sensitivity values used to obtain this final result can then be used in conjunction with the trending data to hypothesize a potential point in the future, being when such an economic environment would allow this system to occur.

3.2.8: Excel model

After modeling and ascertaining all data for each model variant and sensitivity input, the next model then will have to be created in regards to the generation and distribution of power into the grid. Excel will be used to construct this model of which will not be focused upon modeling the physical aspects of the project such as turbines and other infrastructure, but will however focus upon the energy market and project costs. This is because this study isn't focused upon the hydropower plant itself as much research has already been conducted within this area, but to ascertain if it's a viable sustainable solution and how greatly the energy grid in SEQ would benefit from its installation in ensuring grid security.

3.2.8.1: Base Model Spreadsheet

Excel will be used to model different tariffs options to gauge which will be the most cost-effective when selling power onto the grid and also for energy consumption when pumping.

- Four tariff variants will be under analysis.
  - The first scenario will use the current generic Tariff 44 – Business Over 100MWh (Demand Small) [83], with the PHES system being fully dependent upon the grid for energy consumption and distribution.
  - The second scenario will again use the generic tariff 44 but with the addition of a 20MW solar farm to effectively hem system demand.
  - The third scenario will make use of a hypothetical large-scale switchable feed-in tariff, allowing the system to generate and consume power at will without the large cost of the contemporary tariff's demand charge. Essentially this tariff will theoretically allow the system to operate as if on a small-scale domestic tariff (no demand charge) greatly reducing cost. Such a tariff should be implemented in Australia to be used by such stations as they can aide in energy security in numerous ways, being a major asset to not only the owners but to the grid also. It would greatly increase the attractiveness of implementing such projects reducing operation costs greatly, of which is justifiable for such power station as they operating largely to maintain grid security and reduce costs in times of rapidly changing demand.
  - The fourth scenario again is like that of the second scenario, where the hypothetical large-scale switchable feed-in tariff will be used in conjunction with the 20MW solar farm to reduce demand further.

Each of the four scenarios where chosen to quantify the operational costs of such a PHES system in the current and hypothetical energy markets, and to ascertain how much in fact the installed PV would benefit the system

[83] (Dr Malcolm Roberts, 2014)

in reducing long-term cost. The hypothetical scenarios where added into the modeling to identify how much such an ancillary asset would benefit from said tariff as opposed to the current bulk tariff.

3.2.8.2: Full PV Utilization Spreadsheet

After obtaining the baseline data from the base line model, the data from the full PV utilization model will be compiled in the exact same way. However the full PV utilization model will not contain the scenarios that do not incorporate the PV as these are un-necessary now.

3.2.8.3: Future Viability Spreadsheet

This spreadsheet contains a single collective scenario comparing each sensitivity result. The sensitivities have been designed to continually optimise the system in incremental steps to see how the operational outputs and costs change under such conditions. This viability spreadsheet's main purpose is to extrapolate the trending data in a bid to find a point in the future when such a system would become a viable option. This is in addition to seeing how each commodity personally affects the overall system in cost and output.

3.2.8.4: Large-scale Renewable Energy Target (LRET) revenue

If the LRET remains unchanged and active until the year 2030, then this system could acquire a possible 13 000 large scale generation certificates (LGC's) per year for trading under the base line data. This equates to a potential $416,000 in extra revenue for this system per year, however this figure is subject heavily to change as the wholesale market for LGC's is a weekly spot price trading system. This is due to factors such as changing demand and generation levels across the NEM and many other contributing factors, and therefore needs to be noted. Furthermore current deliberations are being held about the LRET, with the main point of discussion being about terminating the scheme for new entrants into the renewable market (see section 2.11) and therefore this additional revenue cannot be relied upon.

3.3: Assumptions and Variability

3.3.1: Assumptions

There were several assumptions made throughout this research project due to the large and constant variability within many of the determining factors that the power industry is subject too, see section *2.---.--- Current Relevant Trends Within Thesis*. Changes within:

- Technology
- Energy usage
- Power network

Are all factors that are broadly changing when and how much energy is required by users at any one time, yet doesn't affect this project in a 'literal' sense. All of these changes where assumed and accounted for within the modeling input data as all data acquired is current.

The assumptions made that are in direct relation to this project and in fact are the major role at play within this study are:

- The PV domestic and commercial market will continue to grow.
- The demand profile for Queensland will become more sporadic.
- The cost of electricity will continue to rise.
- The cost of implementing, operating and maintaining a PV system will decrease.
- PV systems will become more efficient.
- The cost of implementing, operating and maintaining a VRB-ESS system will decrease.

Each of these assumptions where taken when the modeling was conducted to try and determine the point of grid/PV parity.

3.3.2: Variability

Unfortunately this project due to its nature and the environment of which it is intended to operate, results in a high possible degree of variability within the results. So many factors need to be taken into consideration of which are not only directly related to the project, but indirect factors also like the economy and current world events.

Additionally the trends of which this project is somewhat reliant upon are only forecasts, being subject to change. Thus the calculations that where conducted in respect of these trends should not be fully relied upon as a result. The results obtained from the energy and PV sensitivity analysis could be more or less depending on how each market varies in the future. A wide number of factors could affect each market here also such as a silicon shortage, or a new highly efficient and cost effect energy source discovery.

There is also variability within the modeling as alternative methods had to be used in order for the system to operate as envisioned. This mainly is in regards to the VRB-ESS system having to be used as the upper hydro storage catchment.

Chapter 4 – Safety Issues and Assessment

4.1: Risk Assessment Introduction

This research project includes little to no risk within it as only modeling was involved to ascertain the required base figures and data. However the implementation of a hydroelectric dam involves many high risk operations and ongoing risk factors such as if flooding where to occur and the dam burst. Therefore risk assessments need to be carried out upon all facets of the project to insure it can be constructed and operated in a safe manner for many years, even in the face of possible severe weather and other harmful contingency events.

4.2: Bulk Water Safety

The construction of bulk water storage facilities and hydroelectric dams are legislated and closely regulated in Queensland by the Department of Environment and Resource Management (DERM)[84]. Furthermore Australian National Committee on Large Dames (ANCOLD)[85] is the national committee on large dames serving as the industry body that represents its members and associates, and provides guidance in the constructing on large dames. They provide many guidelines within this area such as design criteria, planning and development methods, monitoring systems and risk assessments for a fee of which should be considered and followed in the construction of a dam.

The extensive legislation, risk assessments and guidelines are necessary here largely due to the fact if such a large dam was to fail; it would effectively cause large scale destruction. This destruction could very likely result in the loss of belongings and life, and therefore every possible action to minimize these possibilities needs to be taken.

The criterion for a dam to be regulated within Queensland is simple. The population at any one time that is at risk has to be a minimum of 2, and a failure impact assessment is required if the dam is higher than eight meters with its capacity exceeding 500 ML[86]. There is an additional criterion also but as the proposed project easily fulfills these criteria there is no need for them.

4.3: Risk Assessment

As a result detailed risk assessments need to be carried out upon all facets of the project that could in any way pose a risk at any point. This extensive assessment of the surrounding area is out of the scope of this project. However previous preliminary research that has been conducted in the area as depicted in figures 39 and 40 in Chapter 5 - Ethical Issues and Consequential Effects, shows no significant environmental or heritage areas

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84 (Barker, n/a)
85 ((ANCOLD), 2014)
86 (Barker, n/a)

within the limits of the project. Furthermore there is no urban or industrial developments in the area if the dam was to fail being greatly beneficial.

Furthermore regardless of this more extensive risk analysis upon the area has been previously conducted by Andreas Helwig[87] from the University of Southern Queensland and can be seen in figure 38.

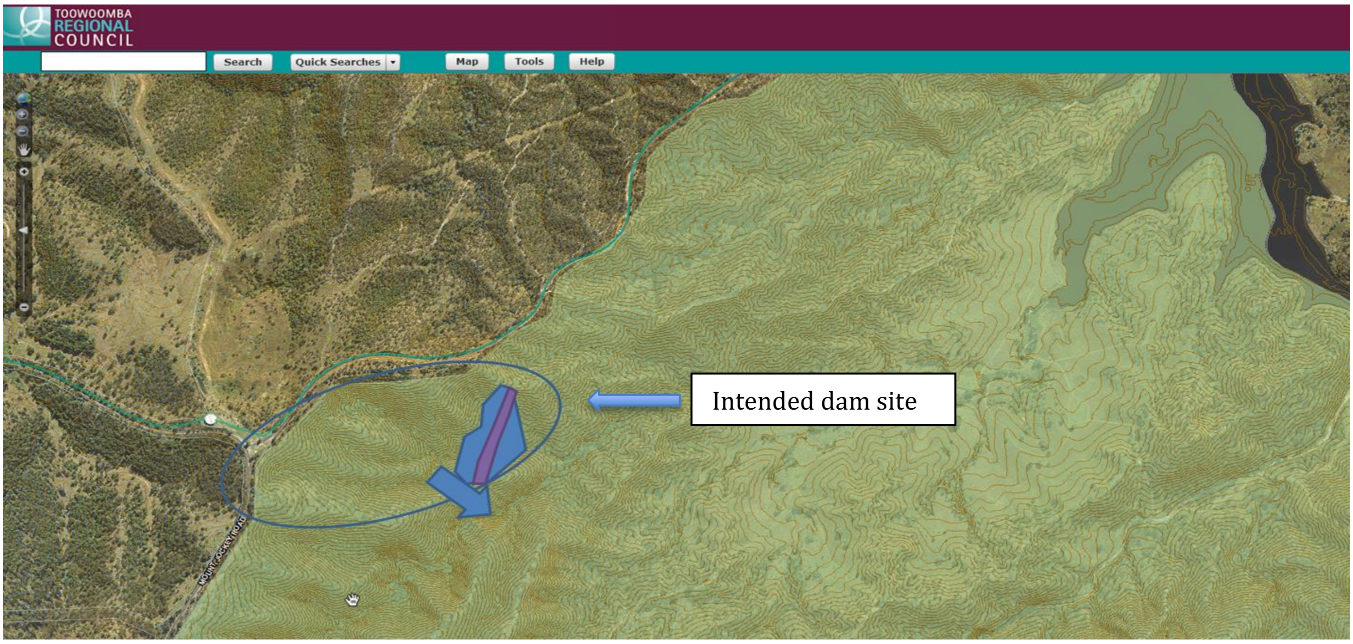


Figure 38: Project area risk analysis (Helwig, 2014)

Suggested dam site depicted by oval with dam wall and spillway indicated by solid hatched area. The green area on the map represents the limits of the Cressbrook Dam Park with Perseverance dam located off map to the left.

The Risk assessment covers a dam size range from 5 to 15 gigalitres with a maximum wall height of 55 meters.

4.3.1: Risk assessment elements

- Environment (Minimal impact)

  Originally cleared for farmland with no original flora with minimal new regrowth.
- Natural runoff (Minimal impact)

  Slight runoff flow reduction to downstream ecosystems.
- Dam wall breach (low risk):

  Sound engineering practice and risk management reduces probability. If breached water will flow downhill back into Cressbrook dam, and mitigating potential risk to persons requires exclusions zones within the park along the natural drainage path.
- Penstock dam (high risk)

[87] (Helwig, 2014)

Requires adequate barrier installation around the perimeter to stop the unauthorized access of any persons.

- Spillway erosion potential (High risk):

  Sound engineering design required in order to reduce spillway erosion risk[88].

88 (Helwig, 2014)

Chapter 5 – Ethical Issues and Consequential Effects

5.1: Ethical Issues

The primary ethical issues that could possibly be concerned with this project arise mainly in two areas being environmental factors and land of which has heritage rights listed upon it. These are an issue due to the large area required to be cleared and developed for such a project.

5.1.2: Environmental factors

The full impact of this project upon the surrounding environment cannot be absolutely quantified until a through environmental impact assessment of the area is conducted. All flora and fauna species within the site area, along with creeks and other high risk ecosystems need to be documented so that the overall impact to the environment can be managed and minimised. Environmental impact assessments need to be carried out in conjunction with the Queensland Government's Department of Environment and Heritage Protection to ensure all protocols are followed and standards met.

However in regards to prior assessments of the area, there are no significant environmentally sensitive locations within the limits of the project which can be seen in figure 39.

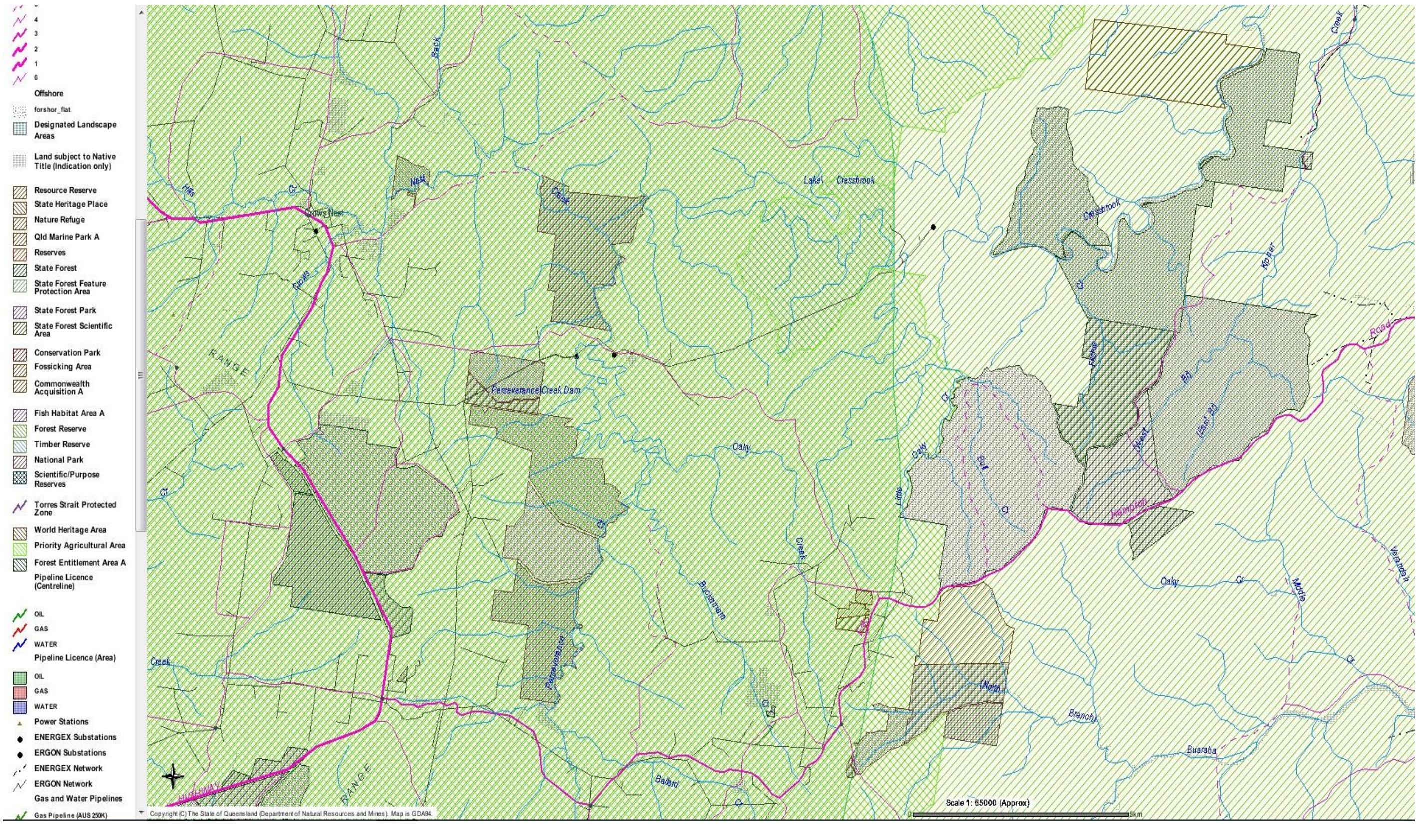


Figure 39: Environment Sensitivity Map. (EnvironmentandHeritageProtection, 2014)

5.1.3: Indigenous Protected Land

There are currently no apparent concerns with indigenous protected land within the project areas as per figure 40. This is also reinforced with the figure 39 as it also makes reference to indigenous protected areas.

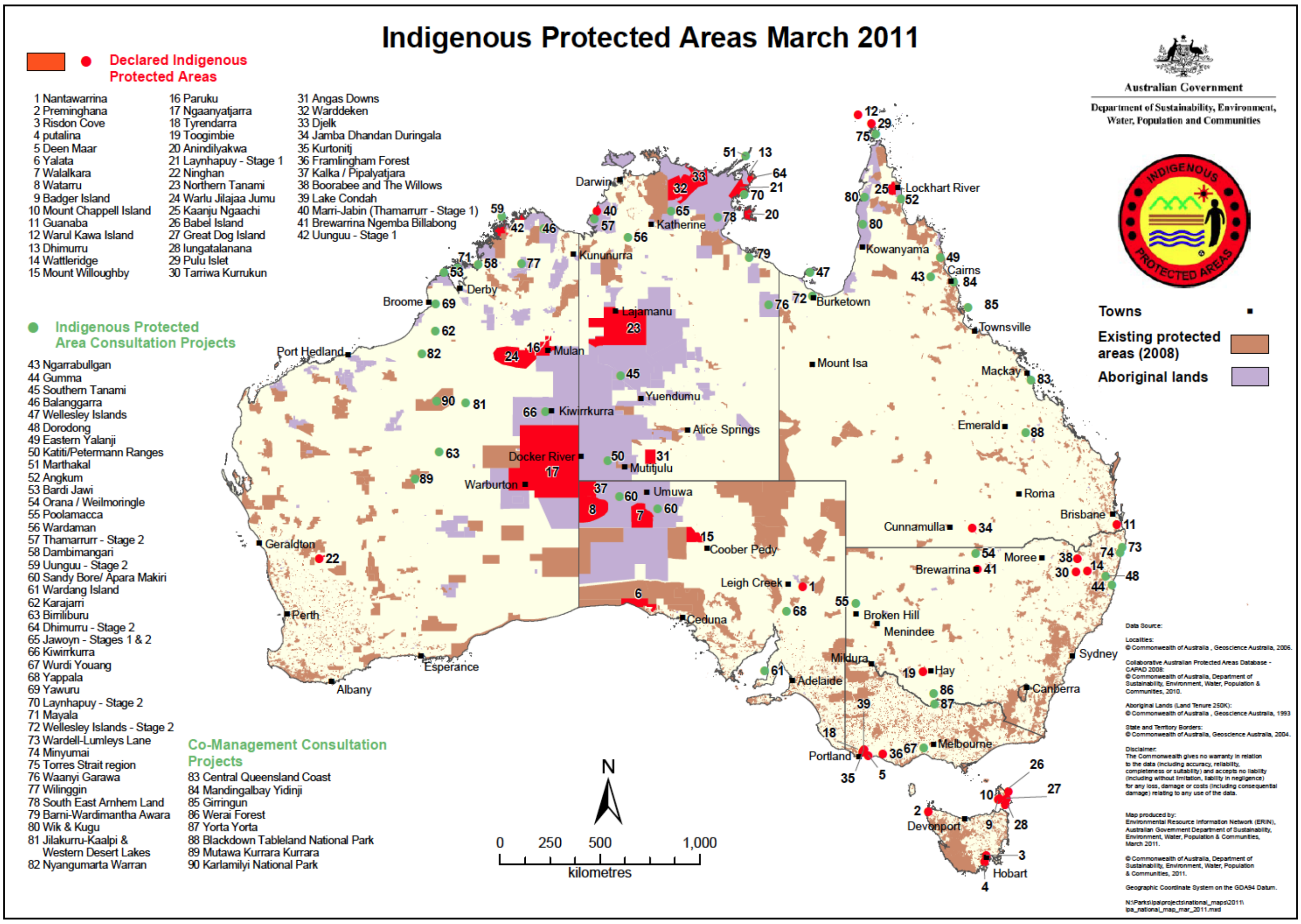


Figure 40: Map depiction of Indigenous protected land within Australia ([Environmental Resource Information Network (ERIN); Australian Government Department of Sustainablity, 2011](#))

5.2: Consequential Effects

5.2.1: Primary effect

The aim of this project is to ultimately have a large consequential effect upon the SEQ electricity grid in several ancillary service areas and to better maintain grid security in the region. The main anticipated effect of this PHES system is to lessen the current aggressive nature of the afternoon shoulder load rise that occurs prior to the peak period which is currently occurring in SEQ. Currently this period of demand thought out the day is very sporadic, changes rapidly and is largely unpredictable. Considering these factors in conjunction with the slow reaction times of the base load generators, it is increasingly difficult for the energy market operators to accurately determine generation capacity required for this period. If the forecast demand for around this period is not within a relatively close tolerance of the real-time demand the cost of energy skyrockets, and if the difference is significant enough power then has to be imported from other states to make up the shortfall. This is an inefficient and costly solution and if the current demand trends are going to continue, implementing this solution more often at larger capacities will only continue to drive the spot-price of electricity around this period up.

5.2.2: Subsidiary grid effects

In addition to this primary sought effect this system can effectively operate in other modes, for example synchronous condenser mode for voltage support. This mode provides reactive power compensation and additional short circuit power capacity if a fault was to occur within a proximity to the plant to again aid in grid security further.

The proposed plant additionally has the operational capacity to halt the need for the base load generators to switch off sections of the station in times of base load. The PHES system does this by providing a dynamic load that can be used to consume just enough generation from such base load stations which alleviates them from the need to switch sections of the station off. Having to shut down and restart large generating units takes considerable time and is very costly, where not doing so is much more efficient and reduces overheads considerably. Therefore providing this service not only benefits the base load generators by giving them additional dynamic loading capacity to maintain operations, but also benefits the PHES system as it is getting cheap additional power for pumping. This additional capacity can then be time-shifted out and sold at a much higher price for profit.

5.2.3: Society effects

The society surrounding the project area along with the population that will be serviced by this proposed project will see no apparent affects from it. However as it serves to stabilise voltage for the SEQ area, this will reduce transients within the system yielding a more reliable and constant energy network. Such a PHES system is designed more for the benefit of the energy utility companies as opposed to the general population. However in aiding the other bulk energy suppliers in their operation, this in turn benefits the grid connected customers with the effects cascading through the energy grid even although they are not apparent to each customer.

One system that may have an effect upon the surrounding society in close proximity to the project site is the wind farm. There have been arguments that such renewable wind farms cause annoying and possibly harmful noise if in close enough proximity to them, and as a result this issue needs further research.

5.2.4: Bulk Water possibility

With this proposed PHES project having a bulk water supply is necessary infrastructure in order for it to operate. With this required dam component it yields the supplementary benefit of an additional bulk water supply capacity for the region of Toowoomba and the surrounding area. The consequential effect from this is the added water storage capacity for domestic use, of which being a great asset especially in SEQ with the every pressing droughts and prolonged periods of sparse rain events.

Chapter 6 - Results and Discussion

6.1: Introduction

The results obtained from the modelling process, all of which relying largely upon many unknown and constantly fluctuating variables returned many interesting results. It was concluded even when considering the most optimal model variant the system is still currently too expensive, with the forecast LCOE of this variation being $0.5380/kWhr. This is as opposed to the more conventional means of generation such as coal fired power plants, of which have an absolute worst case LCOE of $0.150/kWhr[89]. However there are many changes currently occurring within not only the energy market and operations but the world in general, and as a consequence such a PHES scheme will become not only an increasingly viable option but a necessary piece of infrastructure.

Such variables being demand required from the plant per year, cost of electricity, weather events, price fluctuations of equipment used within the model, changes in technology in the board sense.

6.2: Base System Results

6.2.1: Base System - No PV energy costs only

The base system analysis provided some very definitive results which aided greatly for the future viability testing. Preliminary testing of the intended system under the standard bulk tariff 44, with the system being purely grid connected indicated that it would be simply too expensive to operate under current electricity market conditions.

Bulk Tariff 44 – Business Over 100MWh per annum
(Demand Small) - (No PV System 8 Hr Cycle)

Base data:

Demand Charge =	$38.51		per kilowatt per month of chargeable demand			
Energy Charge =	0.13244	c/kWh	All Consumption	Sellback Rate =	0.13244	c/kWh
Service Fee =	$51.65		per metering point per day			
Total Daily load	270	MW				
Pumping period	8	Hrs	∴ Load is:	33.75	MW per/hr	

Scenarios:

	Scenarios	days/year	Service Fee ($)	Total running cost per yr.($)	One day Cost ($)	Daily break-even enery price required ($/MW-hr for 2 hrs min at 100MW production)
1	Operational for:	270	$13,945.50	$25,266,991.50	$69,224.63	$346.12
2	Operational for:	96	$4,958.40	$16,436,278.20	$53,713.33	$268.57
3	Operational for:	48	$2,479.20	$10,817,834.10	$50,315.51	$251.58
4	Operational for:	24	$1,239.60	$7,358,688.30	$47,783.69	$238.92
5	Operational for:	12	$619.80	$4,329,267.90	$46,551.27	$232.76

Bulk Tariff 44 – Business Over 100MWh per annum
(Demand Small) - (No PV System 20 Hr Cycle)

Base data:

Demand Charge =	$38.51		per kilowatt per month of chargeable demand		
Energy Charge =	0.13244	c/kWh	All Consumption		
Service Fee =	$51.65		per metering point per day		
Total Daily load	270	MW			
Pumping period	20	Hrs	∴ Load is:	13.5	MW per/hr

Scenarios:

	Scenarios	days/year	Service Fee ($)	Total running cost per yr.($)	One day Cost ($)	Daily enery price required ($/MW-hr for 2 hrs min at 100MW production)
1	Operational for:	270	$13,945.50	$15,908,089.50	$43,583.81	$217.92
2	Operational for:	96	$4,958.40	$7,597,315.20	$24,827.83	$124.14
3	Operational for:	48	$2,479.20	$4,838,535.60	$22,504.82	$112.52
4	Operational for:	24	$1,239.60	$2,939,206.80	$19,085.76	$95.43
5	Operational for:	12	$619.80	$1,989,542.40	$21,392.93	$106.96

Figure 41: Preliminary system cost – Energy expenses only

89 (FTSE, 2011)

Figure 41 depicts the yearly energy costs of this system when operating over both an 8 hour and 20 hour pumping cycle at 33.75 and 13.5 megawatts respectively, for each of the given days operational. These figures do not include any initial capital costs or operation and maintenance costs for any part of the system.

These results simply indicated that the intended system operating under a conventional tariff like that of bulk tariff 44 is simply not a viable option. For example if the daily beak-even energy price required is considered (figure 41), under the most ideal circumstances the electricity markets spot price still needs to achieve more than $95 per MWhr for a minimum of two hours daily to break even. These figures are rarely achieved in Queensland with the peak energy prices more regularly around $40 dollars being nowhere near the level required. Again this is not considering the initial and running costs of the system equating to an additional 25 million dollars per year approximately in expenditures in addition to the above figures being more then optimal. This will drive the minimum price required considerably higher again making the system less viable again. Thus is why such a system under a contemporary tariff is not economically possible.

However much was learned from the basic system analysis, predominantly the fact that pumping over a longer duration at a lower rate is much more cost effective then pumping at a high rate for short periods of time.

6.2.2: Base System – All elements considered

The same scheme was adopted for the base HOMER model being the two differing pumping rate scenarios over the differing days per year utilised, to see how each compared now with the addition of renewable electricity element into the system. Due to the discussion in section 3.2.6, both scenarios where tested again even although the longer duration approach at a lower rate was previously concluded to be more cost-effective. Furthermore these tests included all capital and operational costs in addition to the potential revenue gained from the PHES system.

Figure 42 is a depiction of the main data set gained from the HOMER model for the Base system, with the red bracketed figures denoting a positive margin or profit. The main areas of interest here is the operating cost per year and total net present value (NPV) of the system after its 40 year life span. The operating cost was of special interest to see if the system would be returning a profit each year with all expense factors considered. Furthermore it should also be noted that even if the system is returning a profit each year, after the 40 year expected life span there still may be an overall loss. This is due to the large initial capital cost of the project that has to be recovered in addition to all other operational costs in order for the project to ultimately yield a profit. Therefore the NPV value of each scenario is of primary concern as it illustrates the ultimate financial standing of the project, being a profit or loss at its conclusion after all operations.

Two main conclusions where reached from this modelling with the first being the system has be to operational for a minimum of 96 days with the sellback rate at 0.6$/kWhr in order for the system to return a profit. The second conclusion that was reached was the same as discussed previously in section 5.2.1, being that the 13.5MW load over a longer duration is a better option than pumping at a higher rate over a shorter period of time.

Bulk Tariff 44 – Business Over 100MWh per annum (Demand Small) - (PV System - 20 Hr Cycle)

Base data:

emand Charge =	$38.51		per kilowatt per month of chargeable demand			
nergy Charge =	0.13244	c/kWh	All Consumption			
ervice Fee =	$51.65		per metering point per day			
Total Daily load	270	MW				
Pumping period	20	Hrs	∴ Load is:	13.5	MW per/hr	

Scenarios:

Days/year	Sellback Rate $/kWh	Levelised Cost of Electricity	Operating cost per yr. ($)	One day Cost ($)	$/MW-hr for 2 hrs opearation at 100MW ouput	Net Present Value (NPV)	PV Size (kW)	FL250 Wind Farm Size (no. x	Renewable Fraction
270	0.132	0.367	$5,938,238.00	$16,269.15	$81.35	$434,422,688.00	20,000	20	0.55
270	0.24	0.262	($1,979,880.00)	($5,424.33)	($27.12)	$309,618,432.00	20,000	20	0.55
270	0.32	0.182	($7,955,815.00)	($21,796.75)	($108.98)	$215,426,576.00	20,000	20	0.55
270	0.45	0.053	($17,667,716.00)	($48,404.70)	($242.02)	$62,364,708.00	20,000	20	0.55
270	0.6	(0.097)	($28,871,598.00)	($79,100.27)	($395.50)	($114,245,080.00)	20,000	20	0.55
96	0.132	0.791	$2,279,298.00	$7,448.69	$37.24	$349,250,976.00	10,000	20	0.62
96	0.24	0.527	($5,106,394.00)	($16,687.56)	($83.44)	$232,838,720.00	10,000	20	0.62
96	0.32	0.328	($10,680,502.00)	($34,903.60)	($174.52)	$144,980,400.00	10,000	20	0.62
96	0.45	0.005	($19,738,422.00)	($64,504.65)	($322.52)	$2,210,717.00	10,000	20	0.62
96	0.6	(0.368)	($30,189,880.00)	($98,659.74)	($493.30)	($162,523,696.00)	10,000	20	0.62
48	0.132	1.575	$4,397,764.00	$20,454.72	$102.27	$374,016,928.00	10,000	0	0.63
48	0.24	1.284	$13,816.00	$64.26	$0.32	$304,917,760.00	10,000	0	0.63
48	0.32	1.063	($2,718,259.00)	($12,643.07)	($63.22)	$252,417,696.00	5,000	10	0.57
48	0.45	0.698	($8,480,309.00)	($39,443.30)	($197.22)	$165,909,584.00	5,000	20	0.66
48	0.6	0.278	($14,818,348.00)	($68,922.55)	($344.61)	$66,010,292.00	5,000	20	0.66
24	0.132	2.701	$4,741,254.00	$30,787.36	$153.94	$365,680,992.00	5,000	0	0.60
24	0.24	2.227	$1,037,188.00	$6,734.99	$33.67	$307,298,016.00	5,000	0	0.60
24	0.32	1.944	($1,758,336.00)	($11,417.77)	($57.09)	$263,235,360.00	5,000	0	0.60
24	0.45	1.415	($6,301,061.00)	($40,915.98)	($204.58)	$191,633,568.00	5,000	0	0.60
24	0.6	0.803	($11,698,016.00)	($75,961.14)	($379.81)	$108,723,776.00	5,000	5	0.67
12	0.132	4.533	$5,794,876.00	$62,310.49	$311.55	$382,288,032.00	5,000	0	0.73
12	0.24	4.109	$3,523,086.00	$37,882.65	$189.41	$346,480,416.00	5,000	0	0.73
12	0.32	3.788	$1,808,528.00	$19,446.54	$97.23	$319,455,776.00	5,000	0	0.73
12	0.45	3.267	($977,628.00)	($10,512.13)	($52.56)	$275,540,768.00	5,000	0	0.73
12	0.6	2.667	($4,192,426.00)	($45,079.85)	($225.40)	$224,869,584.00	5,000	0	0.73

Bulk Tariff 44 – Business Over 100MWh per annum (Demand Small) - (PV System - 8 Hr Cycle)

Base data:

Demand Charge =	$38.51		per kilowatt per month of chargeable demand			
Energy Charge =	0.13244	c/kWh	All Consumption			
Service Fee =	$51.65		per metering point per day			
Total Daily load	270	MW				
Pumping period	8	Hrs	∴ Load is:	33.75	MW per/hr	

Scenarios:

Days/year	Sellback Rate $/kWh	Levelised Cost of Electricity	Operating cost per yr. ($)	One day Cost ($)	$/MW-hr for 2 hrs opearation at 100MW ouput	Net Present Value (NPV)	PV Size (kW)	FL250 Wind Farm Size (no. x	Renewable Fraction
270	0.132	0.493	$15,498,598.00	$42,461.91	$212.31	$528,549,248.00	1,000	10	0.09
270	0.24	0.355	$6,124,000.00	$16,778.08	$83.89	$380,788,128.00	1,000	10	0.09
270	0.32	0.245	($1,284,612.00)	($3,519.48)	($17.60)	$268,327,136.00	1,000	20	0.15
270	0.45	0.078	($12,890,910.00)	($35,317.56)	($176.59)	$85,390,288.00	1,000	20	0.15
270	0.6	(0.115)	($26,282,798.00)	($72,007.67)	($360.04)	($125,690,776.00)	1,000	20	0.15
96	0.132	1.078	$9,680,548.00	$31,635.78	$158.18	$441,158,464.00	1,000	20	0.32
96	0.24	0.772	$1,745,350.00	$5,703.76	$28.52	$316,084,992.00	1,000	20	0.32
96	0.32	0.542	($4,243,477.00)	($13,867.57)	($69.34)	$221,689,920.00	1,000	20	0.32
96	0.45	0.167	($13,975,322.00)	($45,670.99)	($228.35)	$68,297,944.00	1,000	20	0.32
96	0.6	(0.266)	($25,204,378.00)	($82,367.25)	($411.84)	($108,692,880.00)	1,000	20	0.32
48	0.132	1.884	$8,207,528.00	$38,174.55	$190.87	$417,940,928.00	1,000	20	0.48
48	0.24	1.493	$2,706,912.00	$12,590.29	$62.95	$331,240,992.00	1,000	20	0.48
48	0.32	1.198	($1,444,496.00)	($6,718.59)	($33.59)	$265,807,072.00	1,000	20	0.48
48	0.45	0.719	($8,190,533.00)	($38,095.50)	($190.48)	$159,476,976.00	1,000	20	0.48
48	0.6	0.166	($15,974,426.00)	($74,299.66)	($371.50)	$36,788,344.00	1,000	20	0.48
24	0.132	3.190	$7,532,858.00	$48,914.66	$244.57	$409,681,856.00	5,000	0	0.56
24	0.24	2.774	$4,107,316.00	$26,670.88	$133.35	$349,001,440.00	1,000	10	0.48
24	0.32	2.407	$1,178,202.00	$7,650.66	$38.25	$302,833,152.00	1,000	10	0.48
24	0.45	1.777	($3,891,462.00)	($25,269.23)	($126.35)	$227,238,336.00	1,000	20	0.63
24	0.6	1.096	($9,439,639.00)	($61,296.36)	($306.48)	$139,788,736.00	1,000	20	0.63
12	0.132	5.065	$7,486,244.00	$80,497.25	$402.49	$408,947,136.00	5,000	0	0.70
12	0.24	4.657	$5,400,162.00	$58,066.26	$290.33	$376,066,624.00	5,000	0	0.70
12	0.32	4.350	$3,825,764.00	$41,137.25	$205.69	$351,251,168.00	5,000	0	0.70
12	0.45	3.851	$1,267,364.00	$13,627.57	$68.14	$310,926,016.00	5,000	0	0.70
12	0.6	3.358	($1,279,046.00)	($13,753.18)	($68.77)	$264,102,368.00	1,000	10	0.62

Figure 42: Base system results - all elements considered

This can be confirmed by the NPV values of figure 42, with the 20 hour duration being better in each instance except for the 0.6 sellback rate sensitivity. The cause of this discrepancy within the data is unknown because all previous data is consistent, with the reason believed to be associated to the renewables within the system and how the costs vary with them. For example additional costs are incurred with the replacement of the renewable equipment after its useful work life expires, with the 20 hour pumping cycle incurring much greater costs here. This is because the 20 hour system incorporates a 20MW PV array with 20 250 kW wind turbines, as opposed to the 8 hour system only having a 1 MW PV array with 10 250 kW wind turbines. Therefore when these systems have to be replaced, a great deal more capital needs to be spent with the 20 hour cycle as it encumbers much larger renewable plants. This is the believed cause of the single discrepancy within the data. Furthermore the minimum break-even yearly profit was calculated at $21,949,139 to cover all system costs over its forty year life.

Having a higher system renewable fraction was more beneficial for such system with the added profit obtained from the government's renewable energy scheme, but this cannot be relied upon anymore due to its possible abolishment.

Another interesting trend arose when both data sets where compared, being how greatly the renewable fraction varied depending on the systems utilization level. The renewable fraction increased as the days active decreased, along with the renewable generation capacity. This is simply due to less energy is required each year for pumping, and due to how the system had to be structured this was the trend. Due to HOMER being an optimisation package, when the system was operational for fewer days the renewable energy became a more attractive option. This is aside from the fact that the physical renewable generation capacity was greatly decreased.

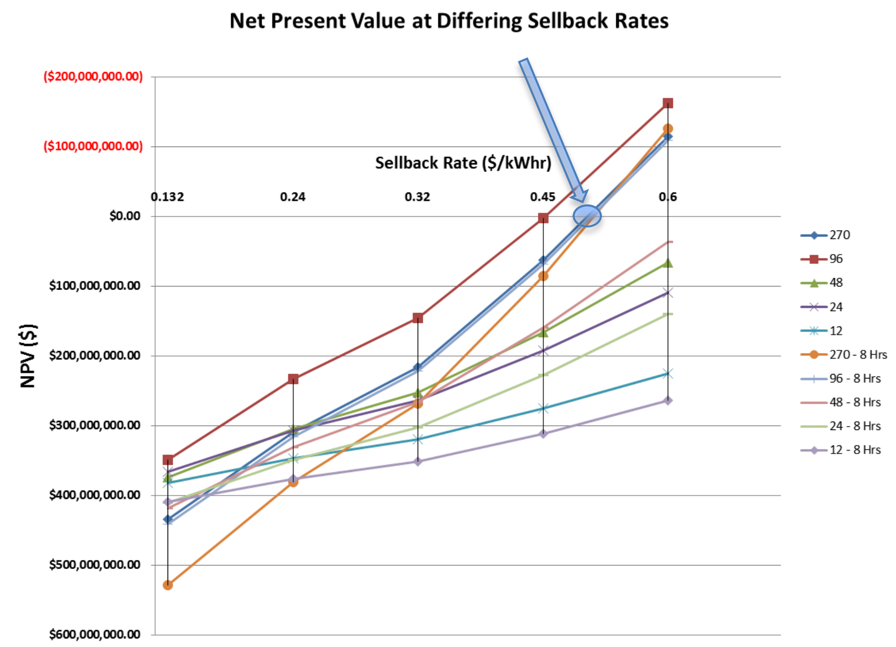


Figure 43: System NPV at differing sellback rates

However for the 8 hour pumping scenario this renewable fraction increase was much more of a significant shift. The renewable fraction when the system was under a heavy yearly load was minimal at best, making 0.09% of the total system load. This fraction however as the systems yearly utilisation factor decreased, increased dramatically to around 70% of yearly load. This is an increase of 61.9%. However for the 20 hour system the renewable fraction only changed a mere 18% for the same period. This yet again makes the 20 hour system more attractive once again as one of the main intentions of this project is to incorporate as much renewable generation as possible. This reaffirms the conclusion reached in section 5.2.1, being that the 20 hour system at 13.5 MW load is the more cost effective solution.

The above figure 43 depicts how the net present value of the system changes as the sellback rate increases, and what rate needs to be achieved to ultimately yield a profit depending on system utilization level. It was found that as the systems yearly utilisation factor increased the profits as seen by the system also increased, of which being an obvious outcome. Also there seemed to be a common sellback rate crossover point highlighted by the arrow that is of note, where several different variants all achieved a 0 NPV. This was approximately around 0.49$/kWhr.

Thus two conclusions where reached here. Either the system has to be operating for a large portion of the year if the sellback rate and other energy factors are to remain at current levels, or if a sellback premium can be achieved the number of days operational can be reduced for the plant to still be profitable.

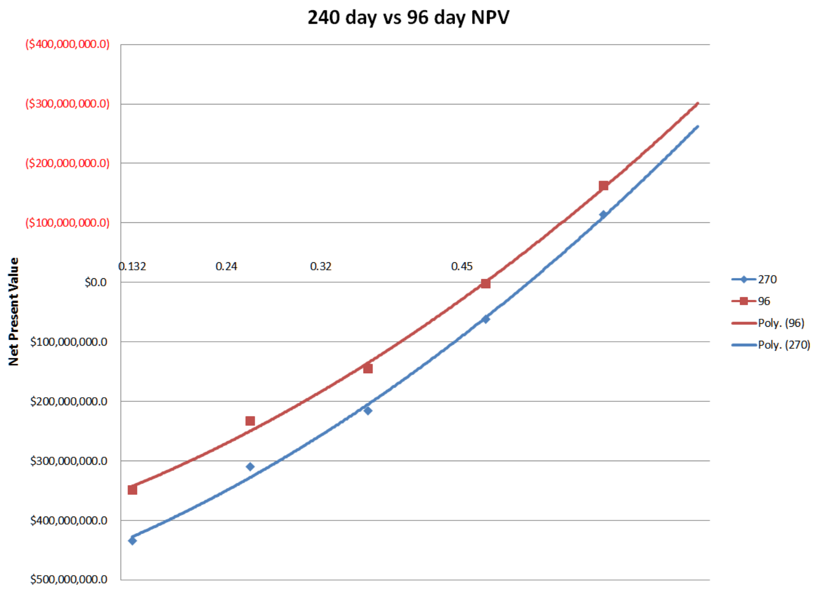


Figure 44: 240 day vs. 96 day utilization

Another point of interst can be seen in figure 44 where it is more cost effective to operate for 96 days per year as opposed to 270 under the 20 hour 13.5 MW scheme. This is due to the extra resources, operating costs and capital required to operate for a longer durations. For example the 270 day load requires a 30MW PV plant in addition to 20 250kW wind turbines for operation. The 96 day load however only requires a 10MW plant again with 20 250kW wind turbines for operation, greatly reduceing initial capital required and overheads without sacrificing a great deal of profit from the drop in yearly ouput.

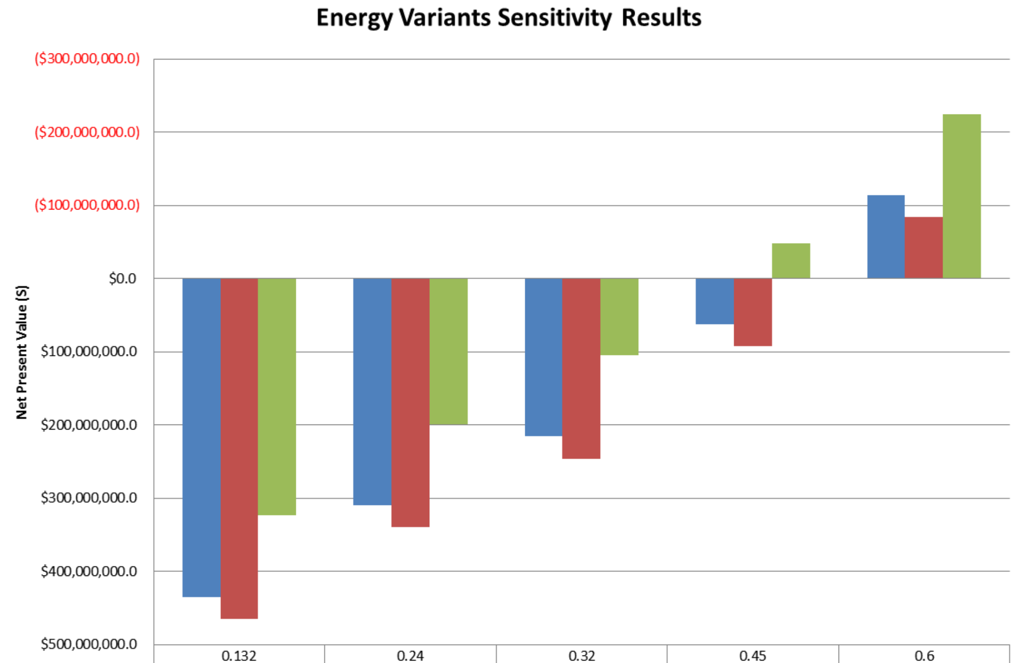
6.3: Future Viability Results

Due to the conclusion reached from the base system models of which being that the 20 hour pumping approach being more beneficial for each case. The 8 hour scenario was disregarded within the future viability results, with the main focus lying with the 20 hour option. Each day's per year scenario along with each differing sellback rate sensitivities where tested along with the additional sensitivities to see how certain trends within the electricity industry will affect the cost of this system.

6.3.1: Energy Variant

One of the main costs incurred of which the government could put into action an incentive plan to negate for such beneficial electrical infrastructure like the proposed PHES project, is cost of demand. Therefore the first energy variant scenarios where created to see what affect upon the systems NPV a changing demand rate has. It also should be noted that it was intended to include the grid power price also within these sensitivity tests, but due to the limitations of HOMER this was not possible as previously discussed.

Figure Energy 45 and Figure 46 below depicts the results gained from the sensitivity analysis that where based around the demand rate in tariff 44. The Results showed that the demand cost alone if abolished could potentially save a project such as this possibly 30% of its original net present value. This was consistent though all test variants. In one instance it reduced the total NPV by more than 50%.



	0.132	0.24	0.32	0.45	0.6
Baseline	$434,422,688.0	$309,618,432.0	$215,426,576.0	$62,364,708.0	($114,245,080.0)
Energy variant 1	$464,447,392.0	$339,643,168.0	$245,451,296.0	$92,389,448.0	($84,220,344.0)
Energy variant 2	$323,505,728.0	$198,701,482.0	$104,509,616.0	($48,552,228.0)	($225,162,064.0)

Figure Energy 45: Energy Sensitivity results for 270 days active

The level of reduction in overall project expense generally coincided with the amount of renewable generation within the system. For example if the renewable fraction within the system was only minor, then the overall demand as seen by the gird isn't reduced greatly by this element and therefore system costs are greater. In the cases which contained a large renewable fraction however, the drop in demand cost didn't affect them as much as the renewables where already reducing these costs. This occurrence was only evident in the 8 hour pumping duration model as the 20 hour pumping models exceeded the daily renewable generating period, thus no such effect on overall demand occurred.

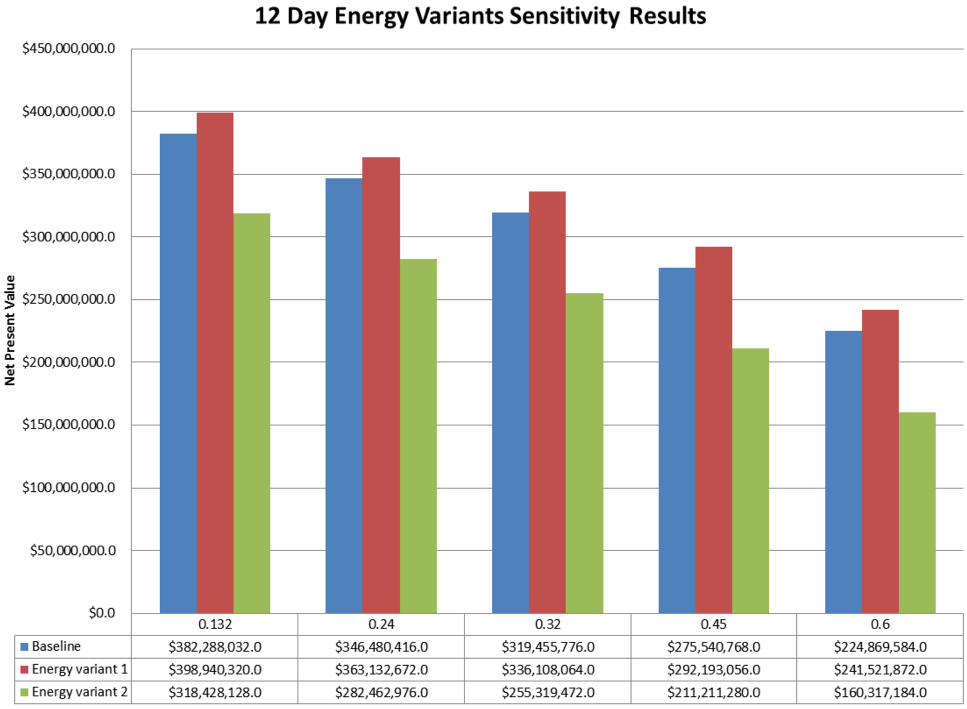


Figure 46: Energy Sensitivity results for 12 days active (Horizontal values are in Reverse)

This is a massive saving in overall cost and would be highly beneficial to such ancillary services, making them a great deal more viable economically. This is why the proposition of a large scale feed in tariff designed specifically for such beneficial generators was proposed.

If such a tariff was implemented the shorter 8 hour pumping duration would then prove to be more beneficial than the 20 hour system by quite a substantial amount, and in turn have to be considered more closely.

8 hours vs. 20 hours pumping duration minus demand cost at 270 days active (NPV)

Sellback rate	8 Hour ($)	20 Hour ($)	Difference ($)
0.132	-310,010,432	-323,505,728	13,495,296
0.24	-162,249,328	-198,701,482	36,452,154
0.32	-49,788,316	-104,509,616	54,721,300
0.45	133,148,520	48,552,228	84,596,292
0.6	344,229,632	225,162,064	119,067,568

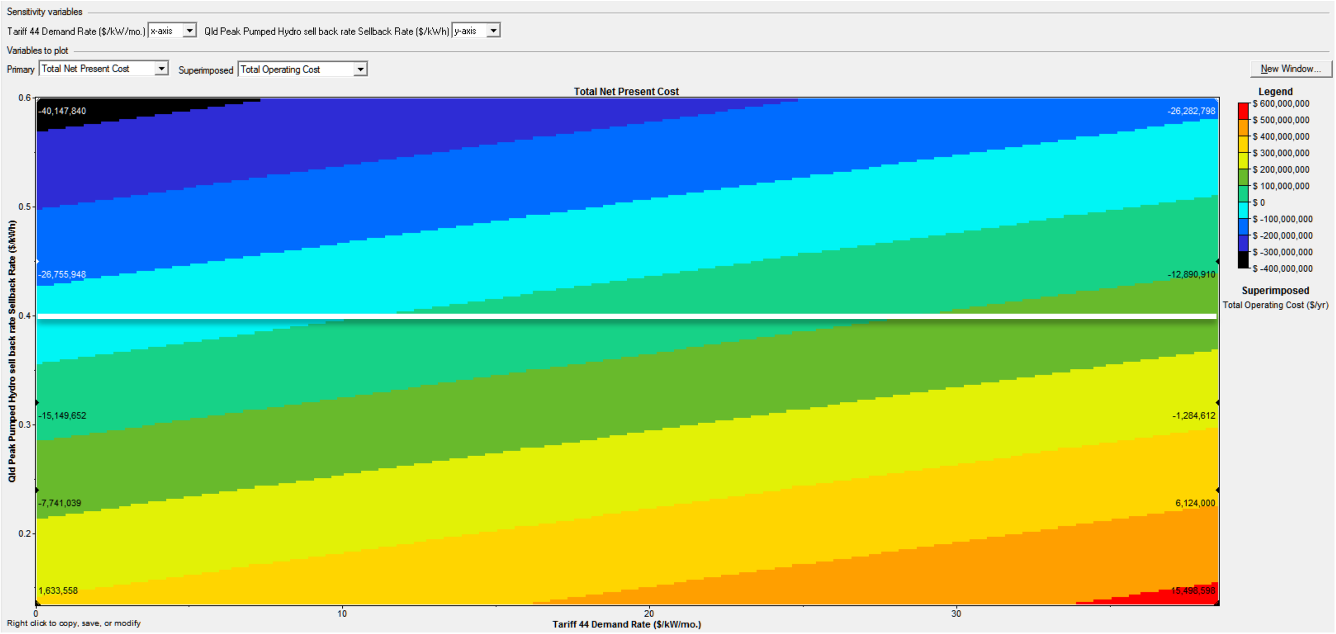


Figure 47: Surface plot of Demand rate vs. Sellback rate (Effects on NPV of 8 hour 270 day system with yearly operating costs superimposed)

Figure 47 is a surface plot of demand rate vs. sellback rate of the 8 hour 270 day systems NPV (with yearly operating costs superimposed).This graph depicts the finding as stated above, where the demand rate plays a vital role in the economic standing of the system. The level of cost reduction by altering the demand rate is depicted by the gradient of line between each intersecting colour; where the steeper the gradient indicates increased change.

6.3.2: PV Variant

The next set of sensitivity inputs had the primary function of determining how much the current trends in the renewable market would affect the overall systems cost (See section 2.6). Due to advances in renewable technologies and improving manufacturing methods the cost of renewables is decreasing steadily and is forecast to continue to do so[90].

Therefore this decline in renewable technology trend was modelled to anticipate future system costs, to gauge its effect upon the system. The capital, replacement and operation and maintenance costs of the renewable technologies within the system where all incrementally decreased in steps of 10%. This are rather drastic and unrealistic reductions in cost for such technologies over short periods of time, however this approach was chosen to see clear data trends.

Approximate Values:

- 270 days: Reduction in cost by 10 – 12 million dollars per variant.
- 96 days: Reduction in cost by 3 – 5 million dollars per variant.
- 48 days: Reduction in cost by 2.5 – 3 million dollars per variant.

90 (Shahan, 2014)

- 24 days: Reduction in cost by 1.5 – 2.5 million dollars per variant.
- 12 days: Reduction in cost by 1.6 million dollars per variant.

The reduction in cost did have some variations from the trend which was due to the optimal renewable fraction changing between iterations. For example if the optimal system for PV variant 1 included 20 MW of installed solar, then the second variant for the same data set included only 10 MW of solar for its optimal system configuration. Then obviously a price anomaly would occur here as the systems renewable costs differ from one another.

The testing conducted upon the PV within this system ended up being surprisingly uneventful and unrewarding. The reduction in capital and operation costs for the renewable systems did not create many savings even when reduced in large steps being 10% of original value each time. The optimal savings margin was approximately 12 million dollars after the forty year working life of the PHES system, that of which not being as significant as was expected.

Additionally this set of sensitivity results had an additional aim, to see if the renewable fraction would increase as the cost of renewables decreased.

All renewable fractions are percentages of total load:

- 270 days: The renewable fraction increased from PV variant 1 to PV variant 2 from 0.55 to 0.68, and this occurred for each sellback rate.
- 96 days: The renewable fraction remained constant at 0.62 for all model variants.
- 48 days: The renewable fraction was quite sporadic for this scenario. When under the 0.132 sellback rate the renewable fraction remained constant at 0.64 for all variants, then for the sellback rate of 0.24 it decreased to 0.57. After the baseline decrease here it rose back again to the baseline previous value of 0.64 and held constant. This anomaly occurred again for the sellback rate of 0.32, however the PV variant 1 didn’t return to 0.64 but rose to 0.67. After this it decreased once again to the baseline value. Then for the renaming sellback rates of 0.45 and 0.6 the fraction rose again to 0.67 and held constant throughout. These results are not entirely understood.
- 24 days: For the sellback rates of 0.132 and 0.24 it was only until PV variant 3 that changes where evident, being a rise in renewable generation from 0.6 to 0.78. Then in the 0.32 sellback rate case this change occurred earlier at PV variant 2 and increased again to 0.78 in PV variant 3. This was again the case for the sellback rate scenario of 0.45 with the change occurring under PV variant 1, holding for PV variant 2 and then increasing to 0.72 for PV variant 3. 0.6 Sellback case stated at 0.67, increased to 0.72 and then maintained this rate.
- 12 days: The renewable fraction remained constant at 0.73 for all model variants.

The full set of results is located in the Appendix (B).

A single variant set produced data that resembled the intended outcome of this experiment, being the 24 day utilization test. This test was the only one that resembled the desired trend of a slow increase in the systems renewable fraction as the renewable costs decreased over the changing sellback prices. The remaining scenarios either exhibited no change in renewable fraction at all or seemingly random variations in renewable fraction and renewable capacity between each variant. This was rather surprising as each iteration differed by -10% in renewable costs being significant by contemporary standards, and thus it was expected that a more definitive rise in renewable capacity in doing so was to occur in each data set.

6.4: Conclusions

The one of the main outcomes that was hoping to be achieved by the future viability modeling, being the extrapolation of the current data to try and define and point in future when this system would be viable was not able to be achieved accurately. This was due to so many contributing factors constantly changing such as the economy, technology costs, trends and energy supply/demand in addition to the spot price market only being a few.

Additionally the power climate within SEQ and Australia if the influx of solar power continues to rise may deteriorate to a point where the viability of this proposed PHES may go beyond purely economic considerations. It is becoming a real possibility that such ancillary assets may become more vital in order to simply maintain an acceptable supply. Taking this and all modeling data into consideration along with what is currently occurring in South Australia as discussed In section 2.4.1, it is believe that the implementation of a PHES system for SEQ would be most beneficial to be undergone in approximately 15-20 years. This could be drastically reduced if certain measures are taken to increase the viability of such a project. To do this the possible enactment of a large scale switchable feed in tariff for beneficial ancillary services would be one of the most beneficial causes of action, with the main focus on eliminating the demand charge for such assets.

Furthermore it was found that the wind farm possibility proved to be very affective within the system and occurred in many optimal models. This option needs to be further researched to ascertain if a larger scale wind farm would be possible at the intended location. There is much legalisation surrounding wind farms within Australia in addition to many people opposed to the option. However if it does prove to be possible the option of a wind farm at a much larger capacity should be investigated.

Chapter 7 – Resource Planning and Timelines

7.1: Resource analysis

7.1.1: Computer Software

The software resources required to conduct this project where simple and free to ascertain. First of all Excel had to be acquired in order to conduct the economic analysis of the project. This had been previously acquired as it is a largely used program of which comes within the Microsoft Word Package. The second major resource that had to be acquired was another piece of computer software called HOMER. HOMER was used mainly to model the PV and grid system in conjunction with the loading profiles to ascertain the most suitable option and ultimately yield a variety of data points of interest. This program was simply downloaded for free under a student license of which spans six months.

7.1.2: Data Acquisition

Several different forms of data had to be acquired for the modeling process, of which being mainly the daily solar radiation levels for the Cressbrook dam area. This was of importance to acquire in order for the daily PV output to be accurately modeled within the system. This data was obtained free from the previous year (2013) from the Bureau of Meteorology[91].

Do to the nature of this project being it only involves simulations and basic computer software, the resources required thought the duration of the project where only minimal.

[91] (Commonwealth of Australia 2014; Dr Malcolm Roberts, 2014)

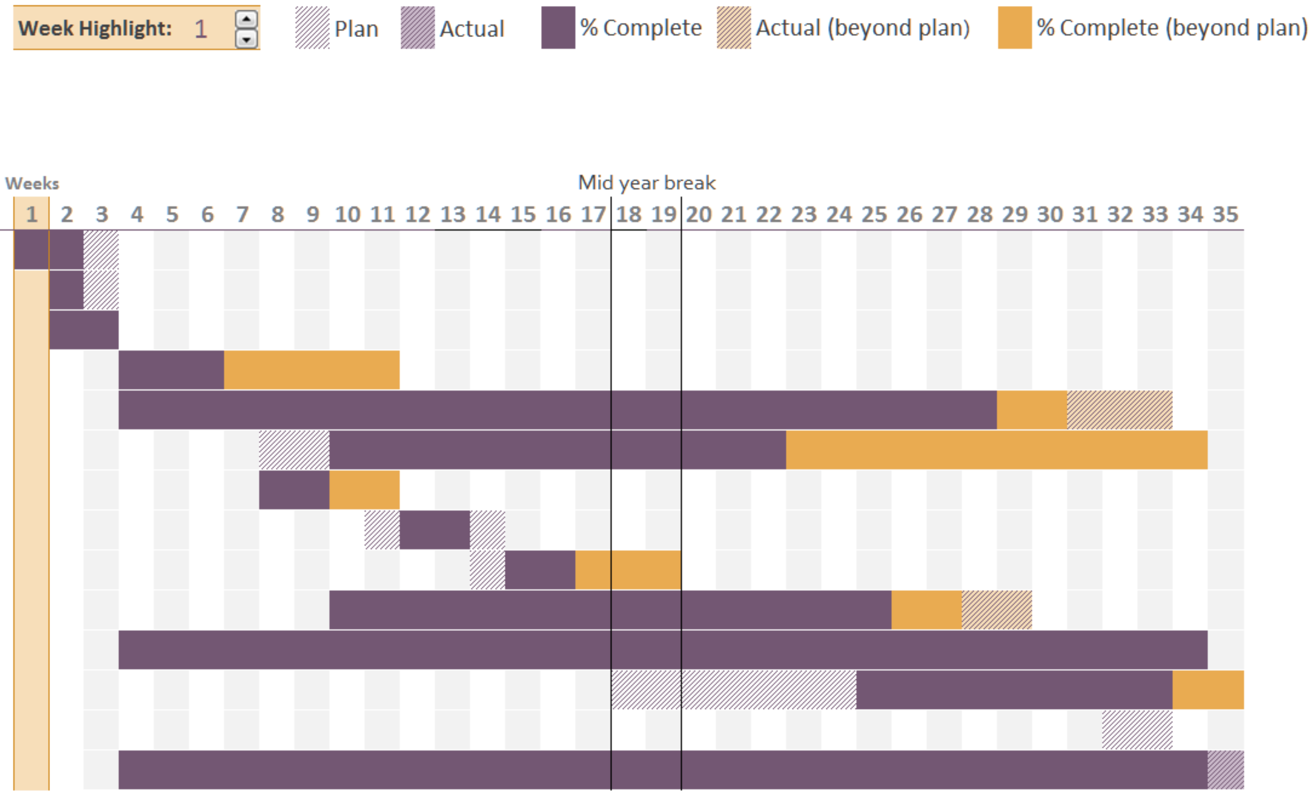
7.2: Time line

(To be updated as necessary)

Aden Tomasel

Thesis Project Timeline

ACTIVITY	PLAN START	PLAN DURATION	ACTUAL START	ACTUAL DURATION	PERCENT COMPLETE
Topic Negotiation	1	3	1	2	100%
Topic Preference	2	2	2	1	100%
Project Specification	2	2	2	2	100%
Thesis Outline	4	3	4	8	100%
Literature Review	4	25	4	30	90%
Methodology	8	15	10	25	100%
Prelimiary Testing	8	2	8	4	100%
Prelimiary report	11	4	12	2	100%
Progress assessment	14	3	15	5	100%
Modelling	10	16	10	20	90%
Thesis Work (generic)	4	31	4	31	100%
Discussion of Results	18	16	25	30	100%
Bulk Water Possibility	32	2	0	0	0%
Dissertation	4	32	4	35	90%



Chapter 8 - Conclusions

8.1: Conclusions

The modelling within this project brought about several conclusions for the PHES hybrid system researched within this paper. The first conclusion was that such a system within the current Australian power climate is simply not a economically feasible option. Electricity prices within in the NEM spot price market would have to achieve unusually high rates for a minimum of 3 hours per day, for more than 90 days per year for the system to ultimately yield a return. With this in consideration, even under optimal operating conditions the system is still a very expensive exploit.

Additionally it was found that the prospect of installing a renewable element in the form of either a large scale PV array, wind farm or a mixture of the two would be highly beneficial to the system. Many of the optimal systems that the HOMER software calculated incorporated a large renewable fraction, often making up more than 50% of the systems total load. The renewable element proved to be highly beneficial as it greatly aided the system when pumping by reducing the yearly demand and electricity costs that otherwise would be incurred. This in addition to the possible onset of renewable/grid parity due to the rising cost of electricity with the falling cost of renewables, made the renewable option more attractive once again. Furthermore excess power generated from these elements can be stored and time shifted to then be sold for a profit, being additional revenue income.

It was also discovered from an initial evaluation of the proposed site, that the location is very well suited for a pumped hydro project. There is the required elevation and space in addition to the location having no environmentally sensitive or culturally significant areas. Furthermore there is no residential area surrounding the proposed site of which enabling the possibility of a wind farm from primary inspection.

It was also discovered that one of the major hindering cost considerations of such beneficial power plants is the demand cost that is incurred each month from pumping. This cost is considerably high each month for systems that operate within the megawatt region, of which is worsened again due to the high level of usage intermittency of such plants. Therefore if a tariff specific to beneficial ancillary services like that of PHES plants could be designed and implemented that did not contain a demand change, this would greatly aid the possibility of projects such as this.

Another conclusion was reached not within the modelling stages but within the literature review, and is one that many people are coming too. It is that with the current grid structure and operation limitations associated with it, even with all the capabilities of the NEM if the installed PV capacity continues to increase many problems will ensue if no countermeasures are taken. Such problems that are associated with in influx of PV are already occurring largely in South Australia and abroad, and will continue to push energy prices up as the compensation measures to counteract such implications are costly.

8.2: Recommendations

The possible future problems caused by solar and other intermittent generation sources will not only be costly, but could possibly lead to a compromise in grid security. Affective countermeasures need to be taken to combat the possible grid implications of such systems, like that of hydro generation. Pumped hydro generation due to its fast reaction times is perfectly suited to maintain grid security under such circumstances, and needs consideration if energy security is to be ensured for the future.

Currently such systems with large renewable fractions to aid the environment further are simply too expensive. To make such beneficial generation assets possible, a large scale switchable feed in tariff is the main recommendation to increase interest and commitment to projects such as this. A tariff designed especially for ancillary assets that aim to maintain grid stability would benefit most from a tariff that does not include a demand charge, and that is optimised for such projects. This charge is a substantial inhibiter of such projects economically mainly due to their high level of usage intermittency, and is why a large scale feed-in tariff for Australia needs to be considered.

8.3: Further Research

Further research needs to be conducted with alternate software, as HOMER simply did not have the capability to construct the model how it was intended to operate. This is due to PHES being a relative new concept with HOMER not catering for such systems. Because of this many alternate methods of modeling had to be applied to yield results as accurate as possible. This was one of the major limitations faced throughout the modeling process, and as a result the results contain a certain margin of error within them.

Additional research into the possible wind farm element also should also be considered, as this method of renewable generation proved to be very effective and highly utilised within many of the optimal models. Further research needs to be conducted on the associated costs, possible wind farm scale and level of the areas seasonal winds. Also area legibility for a large scale wind farm is a major factor that needs additional research as Australia has considerable legislation upon the matter with a lot of the general public opposed to the option.

The bulk water possibility that is created from the upper catchment of the PHES system also needs further research. There is additional possible revenue to be made here though the sales of water for commercial usage. Also the level of possible water moment between each catchment needs further review as both catchments are used for urban and industrial water supply. The operation of this system, with the movement of water when doing so cannot hinder the possible sales of water from any associated catchment. This could occur if water is taken from a lower catchment for storage, where as a result this drops the water level past satisfactory levels of the given lower catchment resulting in water sales unable to occur form this bulk water site.

Chapter 9 – Appendices

Appendix A: Project Specification

UNIVERSITY OF SOUTHERN QUEENSLAND
FACULITY AND ENGINEERING AND SURVEYING
ENG4111/4112 Research Project
PORJECT SPECIFICATIONS

FOR: **ADEN TOMASEL**

TOPIC: The energy storage potential of a hybrid renewable generation grid connected to a pumped hydro-generation plant for effective connection into the energy market, off peak switchable developing load demand market and act as ancillary regional voltage support and bulk water supply.

SUPERVISORS: Mr. Andreas Helwig
Assoc Prof Tony Ahfock.

PROJECT AIM: To investigate the potential mitigation of South East Queensland's rapid fluctuation in afternoon demand shoulder loads, due to weather induced rapid losses in solar generation. This will be done by utilising a hybrid grid connected to a pumped hydro-generation plant, with two potential forms of renewable energy under investigation.

PROGRAMME: (Issue A, 18 March 2014)

1. Conduct all necessary background research on existing pumped storage systems and collate required data on Southeast Queensland's weather, solar and wind trends.
2. Use HOMER energy to model the annual expected renewable energy outputs for two options. The first option is a large solar array 2 – 10 MW system, with the second option being a large wind farm of the same rating.
3. Generate an Excel spread sheet for pumped hydro storage head / energy stored along with the potential bulk water supply based on known regional water supply dam data.
4. Investigation will also be conducted into the energy market for a potential off peak switchable load market, as Pumped hydro can absorb both renewable and off-peak 'cheap' energy.
5. Study the potential of this hybrid energy storage system to provide effective regional supply power factor correction and voltage support.
6. Conduct a financial analysis to assess how such a system could potentially fit into the energy market, whilst also being profitable and beneficial to not only the grid but also the environment.

As Time permits:

7. Create a life cycle of the infrastructure to determine potential operational life span.
8. Research will also be conducted into how such a hybrid energy system can be linked into Queensland's infrastructure development.

AGREED:

…………………………... (Student) …………………………………/……………………………(Supervisors)

___/___/___ ___/___/____ ___/___/____

Appendix B: Modeling Results (Complete Set)

Bulk Tariff 44 – Business Over 100MWh per annum
(Demand Small) - (PV System - 20 Hr Cycle)

Base data:

Demand Charge =	$38.51		per kilowatt per month of chargeable demand
Energy Charge =	0.13244	c/kWh	All Consumption
Service Fee =	$51.65		per metering point per day
Total Daily load	270	MW	
Pumping period	20	Hrs	**∴ Load is: 13.5 MW per/hr**

Scenarios:

Days/year	Scenarios	Sellback Rate $/kWh	Levelised Cost of Electricity	Operating cost per yr.($)	One day Cost ($)	Net Present Value (NPV)	PV Size (kW)	FL250 Wind Farm Size (no. x 250kW)	Renewable Fraction %
270	**Baseline**	0.132	0.367	$5,938,238.0	$16,269.1	$434,422,688.0	20,000	20	0.55
	Energy variant 1	0.132	0.393	$7,843,134.0	$21,488.0	$464,447,392.0	20,000	20	0.55
	Energy variant 2	0.132	0.274	$2,216,154.0	$6,071.7	$323,505,728.0	1,000	20	0.17
	PV variant 1	0.132	0.361	$5,848,236.0	$16,022.6	$426,641,600.0	20,000	20	0.55
	PV variant 2	0.132	0.352	$4,166,118.0	$11,414.0	$415,765,792.0	30,000	20	0.68
	PV variant 3	0.132	0.342	$4,041,120.0	$11,071.6	$404,683,072.0	30,000	20	0.68
	PV/Energy variant 1	0.132	0.386	$6,160,422.0	$16,877.9	$456,312,224.0	30,000	20	0.68
	PV/Energy variant 2	0.132	0.377	$6,035,422.0	$16,535.4	$445,229,504.0	30,000	20	0.68
	Optimal variant	0.132	0.259	($2,226,890.0)	($6,101.1)	$305,887,552.0	30,000	20	0.68
	Baseline	0.24	0.262	($1,979,880.0)	($5,424.3)	$309,618,432.0	20,000	20	0.55
	Energy variant 1	0.24	0.287	($74,982.0)	($205.4)	$339,643,168.0	20,000	20	0.55
	Energy variant 2	0.24	0.168	($5,701,963.0)	($15,621.8)	$198,701,482.0	1,000	20	0.17
	PV variant 1	0.24	0.255	($2,069,880.0)	($5,670.9)	$301,837,376.0	20,000	20	0.55
	PV variant 2	0.24	0.246	($3,752,000.0)	($10,279.5)	$290,961,504.0	30,000	20	0.68
	PV variant 3	0.24	0.237	($3,876,996.0)	($10,621.9)	$279,878,716.0	30,000	20	0.68
	PV/Energy variant 1	0.24	0.280	($1,757,694.0)	($4,815.6)	$331,508,000.0	30,000	20	0.68
	PV/Energy variant 2	0.24	0.271	($1,882,694.0)	($5,158.1)	$320,425,248.0	30,000	20	0.68
	Optimal variant	0.24	0.153	($10,145,008.0)	($27,794.5)	$181,083,280.0	30,000	20	0.68
	Baseline	0.32	0.182	($7,955,815.0)	($21,796.8)	$215,426,576.0	20,000	20	0.55
	Energy variant 1	0.32	0.208	($6,050,918.0)	($16,577.9)	$245,451,296.0	20,000	20	0.55
	Energy variant 2	0.32	0.088	($11,677,989.0)	($31,994.5)	$104,509,616.0	1,000	20	0.17

		PV variant 1	0.32	0.176	($8,045,816.0)	($22,043.3)	$207,645,488.0	20,000	20	0.55
		PV variant 2	0.32	0.166	($9,727,934.0)	($26,651.9)	$196,769,680.0	30,000	20	0.68
		PV variant 3	0.32	0.157	($9,852,932.0)	($26,994.3)	$185,686,944.0	30,000	20	0.68
		PV/Energy variant 1	0.32	0.201	($7,733,629.0)	($21,188.0)	$237,316,144.0	30,000	20	0.68
		PV/Energy variant 2	0.32	0.191	($7,858,629.0)	($21,530.5)	$226,233,408.0	30,000	20	0.68
		Optimal variant	0.32	0.073	($16,120,942.0)	($44,167.0)	$86,891,456.0	30,000	20	0.68
		Baseline	0.45	0.053	($17,667,716.0)	($48,404.7)	$62,364,708.0	20,000	20	0.55
		Energy variant 1	0.45	0.078	($15,761,818.0)	($43,183.1)	$92,389,448.0	20,000	20	0.55
		Energy variant 2	0.45	(0.041)	($21,388,798.0)	($58,599.4)	($48,552,228.0)	1,000	20	0.17
		PV variant 1	0.45	0.046	($17,756,716.0)	($48,648.5)	$54,583,640.0	20,000	20	0.55
		PV variant 2	0.45	0.037	($19,438,832.0)	($53,257.1)	$43,707,844.0	30,000	20	0.68
		PV variant 3	0.45	0.028	($19,563,832.0)	($53,599.5)	$32,625,108.0	30,000	20	0.68
		PV/Energy variant 1	0.45	0.071	($17,444,528.0)	($47,793.2)	$84,254,320.0	30,000	20	0.68
		PV/Energy variant 2	0.45	0.062	($17,569,528.0)	($48,135.7)	$73,171,584.0	30,000	20	0.68
		Optimal variant	0.45	(0.056)	($25,831,842.0)	($70,772.2)	($66,170,396.0)	30,000	20	0.68
		Baseline	0.6	(0.097)	($28,871,598.0)	($79,100.3)	($114,245,080.0)	20,000	20	0.55
		Energy variant 1	0.6	(0.071)	($26,966,700.0)	($73,881.4)	($84,220,344.0)	20,000	20	0.55
		Energy variant 2	0.6	(0.190)	($32,593,684.0)	($89,297.8)	($225,162,064.0)	1,000	20	0.17
		PV variant 1	0.6	(0.103)	($28,961,598.0)	($79,346.8)	($122,026,152.0)	20,000	20	0.55
		PV variant 2	0.6	(0.112)	($30,643,716.0)	($83,955.4)	($132,901,976.0)	30,000	20	0.68
		PV variant 3	0.6	(0.122)	($30,768,716.0)	($84,297.9)	($143,984,720.0)	30,000	20	0.68
		PV/Energy variant 1	0.6	(0.780)	($28,649,412.0)	($78,491.5)	($92,355,536.0)	30,000	20	0.68
		PV/Energy variant 2	0.6	(0.087)	($28,774,412.0)	($78,834.0)	($103,438,264.0)	30,000	20	0.68
		Optimal variant	0.6	(0.205)	($37,036,728.0)	($101,470.5)	($242,780,256.0)	30,000	20	0.68
	96	**Baseline**	0.132	0.791	$2,279,298.0	$7,448.7	$349,250,976.0	10,000	20	0.62
		Energy variant 1	0.132	0.851	$3,986,612.0	$13,028.1	$375,877,696.0	10,000	20	0.62
		Energy variant 2	0.132	0.577	($2,122,690.0)	($6,936.9)	$255,117,472.0	1,000	20	0.37
		PV variant 1	0.132	0.78	$2,224,294.0	$7,268.9	$344,771,520.0	10,000	20	0.62
		PV variant 2	0.132	0.77	$2,169,294.0	$7,089.2	$340,929,128.0	10,000	20	0.62
		PV variant 3	0.132	0.76	$2,114,296.0	$6,909.5	$335,812,736.0	10,000	20	0.62
		PV/Energy variant 1	0.132	0.841	$3,913,608.0	$12,789.6	$371,398,272.0	10,000	20	0.62
		PV/Energy variant 2	0.132	0.83	$3,858,608.0	$12,609.8	$366,918,880.0	10,000	20	0.62
		Optimal variant	0.132	0.558	($3,550,186.0)	($11,601.9)	$246,529,968.0	10,000	20	0.62

	Baseline	0.24	0.527	($5,106,394.0)	($16,687.6)	$232,838,720.0	10,000	20	0.62
	Energy variant 1	0.24	0.587	($3,417,079.0)	($11,166.9)	$259,465,456.0	10,000	20	0.62
	Energy variant 2	0.24	0.314	($9,508,382.0)	($31,073.1)	$138,705,232.0	1,000	20	0.37
	PV variant 1	0.24	0.517	($5,161,397.0)	($16,867.3)	$228,359,296.0	10,000	20	0.62
	PV variant 2	0.24	0.507	($5,216,398.0)	($17,047.1)	$223,879,888.0	10,000	20	0.62
	PV variant 3	0.24	0.497	($5,271,396.0)	($17,226.8)	$219,400,496.0	10,000	20	0.62
	PV/Energy variant 1	0.24	0.577	($3,472,082.0)	($11,346.7)	$254,986,048.0	10,000	20	0.62
	PV/Energy variant 2	0.24	0.567	($3,527,083.0)	($11,526.4)	$250,506,640.0	10,000	20	0.62
	Optimal variant	0.24	0.295	($10,935,877.0)	($35,738.2)	$130,117,736.0	10,000	20	0.62
	Baseline	0.32	0.328	($10,680,502.0)	($34,903.6)	$144,980,400.0	10,000	20	0.62
	Energy variant 1	0.32	0.388	($8,991,187.0)	($29,383.0)	$171,607,152.0	10,000	20	0.62
	Energy variant 2	0.32	0.115	($15,082,488.0)	($49,289.2)	$50,846,952.0	1,000	20	0.37
	PV variant 1	0.32	0.318	($10,735,505.0)	($35,083.3)	$140,500,992.0	10,000	20	0.62
	PV variant 2	0.32	0.308	($10,790,506.0)	($35,263.1)	$136,021,584.0	10,000	20	0.62
	PV variant 3	0.32	0.298	($10,845,504.0)	($35,442.8)	$131,542,184.0	10,000	20	0.62
	PV/Energy variant 1	0.32	0.378	($9,046,190.0)	($29,562.7)	$167,127,744.0	10,000	20	0.62
	PV/Energy variant 2	0.32	0.368	($9,101,191.0)	($29,742.5)	$162,648,320.0	10,000	20	0.62
	Optimal variant	0.32	0.096	($16,509,984.0)	($53,954.2)	$42,259,440.0	10,000	20	0.62
	Baseline	0.45	0.005	($19,738,422.0)	($64,504.6)	$2,210,717.0	10,000	20	0.62
	Energy variant 1	0.45	0.065	($18,049,108.0)	($58,984.0)	$28,837,448.0	10,000	20	0.62
	Energy variant 2	0.45	(0.208)	($24,140,410.0)	($78,890.2)	($91,922,760.0)	1,000	20	0.37
	PV variant 1	0.45	(0.005)	($19,793,426.0)	($64,684.4)	($2,268,685.0)	10,000	20	0.62
	PV variant 2	0.45	(0.015)	($19,848,426.0)	($64,864.1)	($6,748,089.0)	10,000	20	0.62
	PV variant 3	0.45	(0.025)	($19,903,424.0)	($65,043.9)	($11,227,491.0)	10,000	20	0.62
	PV/Energy variant 1	0.45	0.055	($18,104,112.0)	($59,163.8)	$24,358,046.0	10,000	20	0.62
	PV/Energy variant 2	0.45	0.045	($18,159,112.0)	($59,343.5)	$19,878,642.0	10,000	20	0.62
	Optimal variant	0.45	(0.227)	($25,567,906.0)	($83,555.2)	($100,510,264.0)	10,000	20	0.62
	Baseline	0.6	(0.368)	($30,189,880.0)	($98,659.7)	($162,523,696.0)	10,000	20	0.62
	Energy variant 1	0.6	(0.308)	($28,500,546.0)	($93,139.0)	($135,896,928.0)	10,000	20	0.62
	Energy variant 2	0.6	(0.581)	($34,591,868.0)	($113,045.3)	($256,657,184.0)	1,000	20	0.37
	PV variant 1	0.6	(0.378)	($30,244,884.0)	($98,839.5)	($167,003,104.0)	10,000	20	0.62
	PV variant 2	0.6	(0.388)	($30,299,884.0)	($99,019.2)	($171,482,512.0)	10,000	20	0.62
	PV variant 3	0.6	(0.398)	($30,354,882.0)	($99,199.0)	($175,961,920.0)	10,000	20	0.62

		PV/Energy variant 1	0.6	(0.318)	($28,555,568.0)	($93,318.8)	($140,376,352.0)	10,000	20	0.62
		PV/Energy variant 2	0.6	(0.328)	($28,610,568.0)	($93,498.6)	($144,855,760.0)	10,000	20	0.62
		Optimal variant	0.6	(0.600)	($36,019,360.0)	($117,710.3)	($265,244,656.0)	10,000	20	0.62
	48	Baseline	0.132	1.513	$3,469,142.0	$16,135.5	$359,380,128.0	10,000	0	0.64
		Energy variant 1	0.132	1.603	$4,831,990.0	$22,474.4	$380,861,152.0	10,000	0	0.64
		Energy variant 2	0.132	1.161	($819,488.0)	($3,811.6)	$275,658,368.0	1,000	20	0.53
		PV variant 1	0.132	1.499	$343,140.0	$1,596.0	$356,078,464.0	10,000	0	0.64
		PV variant 2	0.132	1.485	$3,399,140.0	$15,810.0	$352,776,800.0	10,000	0	0.64
		PV variant 3	0.132	1.471	$3,364,140.0	$15,647.2	$349,475,136.0	10,000	0	0.64
		PV/Energy variant 1	0.132	1.59	$4,796,988.0	$22,311.6	$377,559,488.0	10,000	0	0.64
		PV/Energy variant 2	0.132	1.576	$4,761,988.0	$22,148.8	$374,257,824.0	10,000	0	0.64
		Optimal variant	0.132	1.141	($889,988.0)	($4,139.5)	$271,134,656.0	1,000	20	0.53
		Baseline	0.24	1.171	($1,079,048.0)	($5,018.8)	$278,254,720.0	5,000	10	0.57
		Energy variant 1	0.24	1.264	($286,540.0)	($1,332.7)	$300,183,584.0	10,000	0	0.64
		Energy variant 2	0.24	0.814	($6,045,351.0)	($28,117.9)	$193,289,040.0	1,000	20	0.56
		PV variant 1	0.24	1.159	($1,684,388.0)	($7,834.4)	$275,400,928.0	10,000	0	0.64
		PV variant 2	0.24	1.146	($1,719,388.0)	($7,997.2)	$272,099,264.0	10,000	0	0.64
		PV variant 3	0.24	1.132	($1,754,388.0)	($8,159.9)	$268,797,600.0	10,000	0	0.64
		PV/Energy variant 1	0.24	1.250	($321,540.0)	($1,495.5)	$296,881,952.0	10,000	0	0.64
		PV/Energy variant 2	0.24	1.236	($466,522.0)	($2,169.9)	$293,571,776.0	10,000	5	0.68
		Optimal variant	0.24	0.795	($6,115,852.0)	($28,445.8)	$188,765,296.0	1,000	20	0.53
		Baseline	0.32	0.912	($4,982,590.0)	($23,174.8)	$216,727,632.0	5,000	10	0.57
		Energy variant 1	0.32	1.007	($4,149,579.0)	($19,300.4)	$239,294,912.0	10,000	0	0.64
		Energy variant 2	0.32	0.552	($9,989,400.0)	($46,462.3)	$131,123,488.0	1,000	20	0.53
		PV variant 1	0.32	0.901	($5,279,884.0)	($24,557.6)	$214,116,704.0	5,000	20	0.67
		PV variant 2	0.32	0.889	($5,582,429.0)	($25,964.8)	$211,210,560.0	10,000	0	0.64
		PV variant 3	0.32	0.875	($5,617,429.0)	($26,127.6)	$207,908,880.0	10,000	0	0.64
		PV/Energy variant 1	0.32	0.993	($4,309,815.0)	($20,045.7)	$235,959,952.0	10,000	5	0.68
		PV/Energy variant 2	0.32	0.978	($4,459,745.0)	($20,743.0)	$232,356,128.0	10,000	10	0.71
		Optimal variant	0.32	0.533	($10,059,900.0)	($46,790.2)	$126,599,776.0	1,000	20	0.53
		Baseline	0.45	0.488	($11,651,464.0)	($54,192.9)	$115,926,272.0	5,000	20	0.67
		Energy variant 1	0.45	0.584	($10,200,264.0)	($47,443.1)	$138,799,872.0	5,000	20	0.67
		Energy variant 2	0.45	0.127	($16,398,476.0)	($76,272.0)	$30,104,528.0	1,000	20	0.53

		PV variant 1	0.45	0.476	($11,688,962.0)	($54,367.3)	$113,097,712.0	5,000	20	0.67
		PV variant 2	0.45	0.464	($11,726,464.0)	($54,541.7)	$110,269,136.0	5,000	20	0.67
		PV variant 3	0.45	0.452	($11,763,962.0)	($54,716.1)	$107,440,568.0	5,000	20	0.67
		PV/Energy variant 1	0.45	0.572	($10,237,764.0)	($47,617.5)	$135,971,296.0	5,000	20	0.67
		PV/Energy variant 2	0.45	0.557	($10,803,002.0)	($50,246.5)	$132,374,600.0	10,000	10	0.71
		Optimal variant	0.45	0.108	($16,468,975.0)	($76,599.9)	$25,580,816.0	1,000	20	0.53
		Baseline	0.6	(0.003)	($19,046,556.0)	($88,588.6)	($634,133.0)	5,000	20	0.67
		Energy variant 1	0.6	0.094	($17,595,356.0)	($81,838.9)	$22,239,478.0	5,000	20	0.67
		Energy variant 2	0.6	(0.364)	($23,793,568.0)	($110,667.8)	($86,455,888.0)	1,000	20	0.53
		PV variant 1	0.6	(0.015)	($19,084,054.0)	($88,763.0)	($3,462,704.0)	5,000	20	0.67
		PV variant 2	0.6	(0.026)	($19,121,556.0)	($88,937.5)	($6,291,273.0)	5,000	20	0.67
		PV variant 3	0.6	(0.038)	($19,159,054.0)	($89,111.9)	($9,119,844.0)	5,000	20	0.67
		PV/Energy variant 1	0.6	0.082	($17,632,854.0)	($82,013.3)	$19,410,908.0	5,000	20	0.67
		PV/Energy variant 2	0.6	0.070	($17,670,356.0)	($82,187.7)	$16,582,338.0	5,000	20	0.67
		Optimal variant	0.6	(0.383)	($23,864,068.0)	($110,995.7)	($90,979,592.0)	1,000	20	0.53
	24	**Baseline**	0.132	2.701	$4,741,254.0	$30,787.4	$365,680,992.0	5,000	0	0.60
		Energy variant 1	0.132	2.85	$6,017,860.0	$39,077.0	$385,802,688.0	5,000	0	0.60
		Energy variant 2	0.132	2.175	$652,084.0	$4,234.3	$294,540,576.0	1,000	10	0.52
		PV variant 1	0.132	2.689	$4,723,754.0	$30,673.7	$364,030,176.0	5,000	0	0.60
		PV variant 2	0.132	2.676	$4,706,254.0	$30,560.1	$362,379,328.0	5,000	0	0.60
		PV variant 3	0.132	2.662	$4,054,350.0	$26,326.9	$360,354,112.0	10,000	0	0.78
		PV/Energy variant 1	0.132	2.831	$5,159,792.0	$33,505.1	$383,277,952.0	10,000	0	0.78
		PV/Energy variant 2	0.132	2.806	$5,124,792.0	$33,277.9	$379,976,288.0	10,000	0	0.78
		Optimal variant	0.132	2.155	$611,584.0	$3,971.3	$291,783,456.0	1,000	10	0.52
		Baseline	0.24	2.227	$1,037,188.0	$6,735.0	$307,298,016.0	5,000	0	0.60
		Energy variant 1	0.24	2.418	$2,313,794.0	$15,024.6	$327,419,712.0	5,000	0	0.60
		Energy variant 2	0.24	1.740	($3,091,617.0)	($20,075.4)	$235,532,864.0	1,000	10	0.52
		PV variant 1	0.24	2.257	$1,019,688.0	$6,621.4	$305,647,200.0	5,000	0	0.60
		PV variant 2	0.24	2.245	$1,002,188.0	$6,507.7	$303,996,352.0	5,000	0	0.60
		PV variant 3	0.24	2.230	$350,282.0	$2,274.6	$301,971,104.0	10,000	0	0.78
		PV/Energy variant 1	0.24	2.400	$1,455,726.0	$9,452.8	$324,894,976.0	10,000	0	0.78
		PV/Energy variant 2	0.24	2.375	$1,420,726.0	$9,225.5	$321,593,312.0	10,000	0	0.78
		Optimal variant	0.24	1.719	($3,132,117.0)	($20,338.4)	$232,775,776.0	1,000	10	0.52

		Baseline	0.32	1.944	($1,758,336.0)	($11,417.8)	$263,235,360.0	5,000	0	0.60
		Energy variant 1	0.32	2.091	($632,494.0)	($4,107.1)	$28,313,699.0	5,000	5	0.67
		Energy variant 2	0.32	1.411	($5,917,052.0)	($38,422.4)	$190,998,752.0	1,000	10	0.52
		PV variant 1	0.32	1.932	($1,775,836.0)	($11,531.4)	$261,584,528.0	5,000	0	0.60
		PV variant 2	0.32	1.919	($1,906,340.0)	($12,378.8)	$259,877,552.0	5,000	5	0.67
		PV variant 3	0.32	1.905	($2,445,240.0)	($15,878.2)	$257,908,480.0	10,000	0	0.78
		PV/Energy variant 1	0.32	2.074	($1,339,796.0)	($8,700.0)	$280,832,352.0	10,000	0	0.78
		PV/Energy variant 2	0.32	2.050	($1,374,796.0)	($8,927.2)	$277,530,688.0	10,000	0	0.78
		Optimal variant	0.32	1.390	($5,957,553.0)	($38,685.4)	$188,241,648.0	1,000	10	0.52
		Baseline	0.45	1.415	($6,301,061.0)	($40,916.0)	$191,633,568.0	5,000	0	0.60
		Energy variant 1	0.45	1.560	($5,199,521.0)	($33,763.1)	$211,152,144.0	5,000	5	0.67
		Energy variant 2	0.45	0.876	($10,508,384.0)	($68,236.3)	$118,630,816.0	1,000	10	0.52
		PV variant 1	0.45	1.402	($6,450,868.0)	($41,888.8)	$189,837,968.0	5,000	5	0.67
		PV variant 2	0.45	1.388	($6,473,368.0)	($42,034.9)	$187,892,688.0	5,000	5	0.67
		PV variant 3	0.45	1.372	($6,602,062.0)	($42,870.5)	$185,782,976.0	5,000	10	0.72
		PV/Energy variant 1	0.45	1.543	($5,360,845.0)	($34,810.7)	$208,959,376.0	5,000	10	0.72
		PV/Energy variant 2	0.45	1.521	($6,029,214.0)	($39,150.7)	$205,893,408.0	10,000	5	0.81
		Optimal variant	0.45	0.856	($10,548,885.0)	($68,499.3)	$115,873,712.0	1,000	10	0.52
		Baseline	0.6	0.803	($11,698,016.0)	($75,961.1)	$108,723,776.0	5,000	5	0.67
		Energy variant 1	0.6	0.943	($10,631,038.0)	($69,032.7)	$127,697,584.0	5,000	10	0.72
		Energy variant 2	0.6	0.259	($15,806,078.0)	($102,636.9)	$35,129,300.0	10,000	10	0.52
		PV variant 1	0.6	0.789	($11,844,757.0)	($76,914.0)	$106,760,864.0	5,000	10	0.72
		PV variant 2	0.6	0.772	($11,872,256.0)	($77,092.6)	$104,521,160.0	5,000	10	0.72
		PV variant 3	0.6	0.755	($11,899,756.0)	($77,271.1)	$102,281,456.0	5,000	10	0.72
		PV/Energy variant 1	0.6	0.927	($10,658,538.0)	($69,211.3)	$125,457,888.0	5,000	10	0.72
		PV/Energy variant 2	0.6	0.907	($11,298,864.0)	($73,369.2)	$122,833,912.0	10,000	5	0.81
		Optimal variant	0.6	0.239	($15,846,579.0)	($102,899.9)	$32,372,196.0	1,000	10	0.52
	12	**Baseline**	0.132	4.533	$5,794,876.0	$62,310.5	$382,288,032.0	5,000	0	0.73
		Energy variant 1	0.132	4.731	$6,851,368.0	$73,670.6	$398,940,320.0	5,000	0	0.73
		Energy variant 2	0.132	3.776	$2,304,416.0	$24,778.7	$318,428,128.0	1,000	5	0.51
		PV variant 1	0.132	4.514	$5,777,376.0	$62,122.3	$380,637,216.0	5,000	0	0.73
		PV variant 2	0.132	4.494	$5,759,876.0	$61,934.2	$378,986,368.0	5,000	0	0.73
		PV variant 3	0.132	4.475	$5,742,376.0	$61,746.0	$377,335,552.0	5,000	0	0.73

PV/Energy variant 1	0.132	4.711	$6,833,868.0	$73,482.5	$397,289,472.0	5,000	0	0.73
PV/Energy variant 2	0.132	4.674	$6,025,332.0	$64,788.5	$394,170,464.0	10,000	0	0.87
Optimal variant	0.132	3.754	$2,278,916.0	$24,504.5	$316,554,368.0	1,000	5	0.51
Baseline	0.24	4.109	$3,523,086.0	$37,882.6	$346,480,416.0	5,000	0	0.73
Energy variant 1	0.24	4.306	$4,579,578.0	$49,242.8	$363,132,672.0	5,000	0	0.73
Energy variant 2	0.24	3.350	$22,632.0	$243.4	$282,462,976.0	1,000	5	0.51
PV variant 1	0.24	4.089	$3,505,586.0	$37,694.5	$344,829,568.0	5,000	0	0.73
PV variant 2	0.24	4.070	$3,488,086.0	$37,506.3	$343,178,720.0	5,000	0	0.73
PV variant 3	0.24	4.050	$3,470,586.0	$37,318.1	$341,527,904.0	5,000	0	0.73
PV/Energy variant 1	0.24	4.287	$4,562,078.0	$49,054.6	$361,481,856.0	5,000	0	0.73
PV/Energy variant 2	0.24	4.250	$3,753,544.0	$40,360.7	$358,362,848.0	10,000	0	0.87
Optimal variant	0.24	3.327	($2,868.0)	($30.8)	$280,589,216.0	1,000	5	0.51
Baseline	0.32	3.788	$1,808,528.0	$19,446.5	$319,455,776.0	5,000	0	0.73
Energy variant 1	0.32	3.986	$2,865,020.0	$30,806.7	$336,108,064.0	5,000	0	0.73
Energy variant 2	0.32	3.028	($1,699,468.0)	($18,273.8)	$255,319,472.0	1,000	5	0.51
PV variant 1	0.32	3.769	$1,791,028.0	$19,258.4	$317,804,960.0	5,000	0	0.73
PV variant 2	0.32	3.749	$1,773,528.0	$19,070.2	$316,154,112.0	5,000	0	0.73
PV variant 3	0.32	3.729	$1,756,028.0	$18,882.0	$314,503,264.0	5,000	0	0.73
PV/Energy variant 1	0.32	3.966	$2,847,520.0	$30,618.5	$334,457,216.0	5,000	0	0.73
PV/Energy variant 2	0.32	3.929	$2,038,986.0	$21,924.6	$331,338,240.0	10,000	0	0.87
Optimal variant	0.32	3.005	($1,724,969.0)	($18,548.1)	$253,445,696.0	1,000	5	0.51
Baseline	0.45	3.267	($977,628.0)	($10,512.1)	$275,540,768.0	5,000	0	0.73
Energy variant 1	0.45	3.465	$78,864.0	$848.0	$292,193,056.0	5,000	0	0.73
Energy variant 2	0.45	2.505	($4,497,881.0)	($48,364.3)	$211,211,280.0	1,000	5	0.51
PV variant 1	0.45	3.248	($995,128.0)	($10,700.3)	$273,889,952.0	5,000	0	0.73
PV variant 2	0.45	3.228	($1,012,628.0)	($10,888.5)	$272,239,104.0	5,000	0	0.73
PV variant 3	0.45	3.209	($1,030,128.0)	($11,076.6)	$270,588,288.0	5,000	0	0.73
PV/Energy variant 1	0.45	3.445	$61,364.0	$659.8	$290,542,208.0	5,000	0	0.73
PV/Energy variant 2	0.45	3.408	($747,172.0)	($8,034.1)	$287,423,200.0	10,000	0	0.87
Optimal variant	0.45	2.482	($4,523,383.0)	($48,638.5)	$209,337,472.0	1,000	5	0.51
Baseline	0.6	2.667	($4,192,426.0)	($45,079.8)	$224,869,584.0	5,000	0	0.73
Energy variant 1	0.6	2.864	($3,135,933.0)	($33,719.7)	$241,521,872.0	5,000	0	0.73
Energy variant 2	0.6	1.901	($7,726,821.0)	($83,084.1)	$160,317,184.0	1,000	5	0.73

	PV variant 1	0.6	2.647	($4,209,926.0)	($45,268.0)	$223,218,752.0	5,000	0	0.73
	PV variant 2	0.6	2.627	($4,227,426.0)	($45,456.2)	$221,567,904.0	5,000	0	0.73
	PV variant 3	0.6	2.608	($4,244,925.0)	($45,644.4)	$219,917,088.0	5,000	0	0.73
	PV/Energy variant 1	0.6	2.844	($3,153,433.0)	($33,907.9)	$239,871,040.0	5,000	0	0.73
	PV/Energy variant 2	0.6	2.807	($3,961,969.0)	($42,601.8)	$236,752,016.0	10,000	0	0.87
	Optimal variant	0.6	1.879	($7,752,323.0)	($83,358.3)	$158,443,376.0	1,000	5	0.51

Appendix C: Queensland Government Gazette (Power Tariff Structure)

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Energy Charge -

All Consumption **10.938 c/kWh**

plus a Service Fee per metering point per day of **243.474 c**

The chargeable demand in any month shall be –
(a) the maximum demand recorded in that month; or
(b) 60 per cent of the highest maximum demand recorded in any of the preceding eleven months; or
(c) 75 kilowatts,
whichever is the highest figure.

'Demand' shall mean the average demand in kilowatts over a period of 30 minutes, as measured on the distribution entity's meters.

Customers taking supply under this tariff will not be supplied under any other tariff at the same NMI.

***Tariff 43 (Large)* – General Supply Demand – Time-of-Use (Obsolescent) –**

No new customers will be supplied under this tariff. It is available only to large business customers in Ergon Energy Corporation Limited's distribution area taking supply under Tariff 43 at 30 June 2012. This tariff will only be available until 30 June 2015.

Demand Charge –

$22.530 per kilowatt per month of chargeable demand.

Energy Charge –

For electricity consumed between the hours of 7.00am and 11.00pm, Monday to Friday inclusive -

All Consumption **22.255 c/kWh**

For electricity consumed at other times –

All Consumption **8.896 c/kWh**

plus a Service Fee per metering point per day of **243.474 c**

The chargeable demand in any month shall be –
(a) the maximum demand recorded in that month; or
(b) 60 per cent of the highest maximum demand recorded in any of the preceding eleven months; or
(c) 400 kilowatts,
whichever is the highest figure.

'Demand' shall mean the average demand in kilowatts over a period of 30 minutes, as measured on the distribution entity's meters.

Customers must have the appropriate metering installed in order to access this tariff.

***Tariff 44* – Business Over 100MWh per annum (Demand Small) – Ergon Energy Corporation Limited distribution area ONLY –**

This tariff is available to Ergon Energy Queensland Pty Ltd customers only.

This tariff can be accessed by business customers classified as SAC >100MWh per annum by the distribution entity. The tariff is based on the Ergon Energy Corporation Limited network tariff of Demand Small.

A Standard Asset Customer - Large (SAC - Large) is a business customer in Ergon Energy Corporation Limited's distribution area whose annual energy consumption generally exceeds 100MWh.

This tariff cannot be used in conjunction with any other tariff at that NMI.

Demand Charge –

$38.514 per kilowatt per month of chargeable demand.

Energy Charge –

All Consumption **13.244 c/kWh**

plus a Service Fee per metering point per day of **5165.356 c**

The chargeable demand charge in any month will be the kW amount by which a customer's metered monthly maximum demand is greater than the demand threshold applicable to the customer's network tariff. The demand threshold for Demand Small is 30 kW.

Where the monthly metered maximum demand is less than the demand threshold, the chargeable demand is set to zero and no demand charge is payable for that month.

'Demand' shall mean the average demand in kilowatts over a period of 30 minutes, as measured on the distribution entity's meters.

Customers must have the appropriate metering installed in order to access this tariff.

***Tariff 45* – Business Over 100MWh per annum (Demand Medium) – Ergon Energy Corporation Limited distribution area ONLY –**

This tariff is available to Ergon Energy Queensland Pty Ltd customers only.

This tariff can be accessed by business customers classified as SAC >100MWh per annum by the distribution entity. The tariff is based on the Ergon Energy Corporation Limited network tariff of Demand Medium.

A Standard Asset Customer - Large (SAC - Large) is a business customer in Ergon Energy Corporation Limited's distribution area whose annual energy consumption generally exceeds 100MWh.

This tariff cannot be used in conjunction with any other tariff at that NMI

Demand Charge –

$34.556 per kilowatt per month of chargeable demand.

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