HIPCo Electricity Strategy – Phase 1

Hughenden Irrigation Project Corporation Pty Ltd

ACN

Document Control Table

Version	Author(s)	Notes
1.0	LO'B	Report Framework & Initial Draft
1.2	JG O'Brien	Draft Report for issue

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Executive Summary

[To be completed on receipt of HIPCo comments on draft report]

Recitals

Hughenden Irrigation Project Corporation ("HIPCo") is the developer of a conceptual irrigation project in the Flinders Shire Council area.

W. Wightman Advisory ("WWA") has combined experience of 150 years in the energy infrastructure market in Queensland and Australia. It is an advisory services business that generates commercial and regulatory solutions for clients in energy, agriculture, financial services, medical devices and medical research.

Background

On the 1st of January 2019 HIPCo contacted WWA to request their assistance with the electricity requirements, arrangements and opportunities relating to the project.

Project Summary

There are three water storage areas:

1. The main catchment on the eastern side of the area - Canterbury Dam
2. The Interim Storage area - small water storage on the flat high point on the ridge between the two dams
3. The main water storage - Alstonvale Dam: is the same level as the main catchment area on the other side of the ridge.
4. Pumping arrangements - Core water storage operation: The pumping from the main catchment area to the high interim storage will happen on a continuous basis during the wet season when there is water flow into the catchment. At a concept level this is assumed to be 6 months of the year from December to May.
    a. The pumping head is assumed to be 70m;
    b. For concept purposes this pumping is assumed to be at 5m3/sec and requires a pumping electrical load of 6.9 MW.
5. Pumping arrangements - Irrigation operation: The pumping from the main storage area (Alstonvale Dam) into the irrigation system will happen on a continuous basis during the dry season. At a concept level this is assumed to be 8 months of the year with some overlap with the main pumping for storage from an electrical demand perspective. In preparing this strategy report it is assumed,
    c. The pumping head is 70m;
    d. the pumping electrical load is 3.5 MW.
6. Potential Hydro and Pumped Hydro Energy Storage (PHES) arrangements - Water flows from the interim storage to Alstonvale Dam and is available for hydro generation; there is also the potential to use the Alstonvale Dam and Interim Storage for pumped hydro energy storage; generally outside the wet season. Both these concepts require further investigation and rely

on more specific technical and costing assessment. They are not considered in the Stage 1 assessment.

Assumed Irrigation Infrastructure

Parameter		Description
Alstonvale Dam	**Full supply volume**	500 GL
	Full supply level	320 m AHD
	Dam Invert Level	283 m AHD
Canterbury Dam	**Full supply volume**	100 GL
	Full supply level	308 m AHD
	Dam Invert Level	294 m AHD
Total diversion capacity into Canterbury Dam		500 m^3/s
Canterbury Dam to Alstonvale Dam Transfer Rate		5.0 m^3/s
Annual Demand from Alstonvale Dam		72 GL/year

Electricity Demand and Supply

Electricity Demand

The electrical demand assumptions for Stage 1 operation includes:

1. pumping from Canterbury Dam to the Interim Storage with a maximum demand of 7 MW.
2. pumping from Alstonvale Dam to the irrigation system with a maximum demand of 3.5 MW.

The Canterbury pump station will normally operate for 6 months of the year during and after the wet season to maximise the available water in the Alstonvale Dam.

The Alstonvale irrigation pump station will normally operate for 8 months of year outside the wet season. For electrical demand purposes it is assumed that irrigation pump station can operate at the same time as the Canterbury pump station. There will be commercial value in structuring the dam and irrigation operation such that the pumps do not operate at the same time.

Stage 2 could include an additional Alstonvale pump station that will operate to maintain the desired capacity in the Interim Storage when there is no supply in the Canterbury Dam.

Electricity Supply – Initial Concept Analysis

The Canterbury pumping electricity supply is assumed to be supplied via the Ergon Energy Corporation Limited (EECL) grid.

The Alstonvale pumping to the irrigation system is assumed to be supplied via the 66kV distribution system owned and operated by EECL.

Additional Generation – Stage 2

Future commercial optimisation could include hydro generation on the Alstonvale Dam infeed. The electricity supply could also be complemented with generation from new solar generation or tapping into existing solar generation near Hughenden connection point.

There is the potential to develop local solar or wind generation specifically to feed the pumping loads to reduce the reliance on the EECL grid supply and to provide additional export capacity if electricity market prices make that economic.

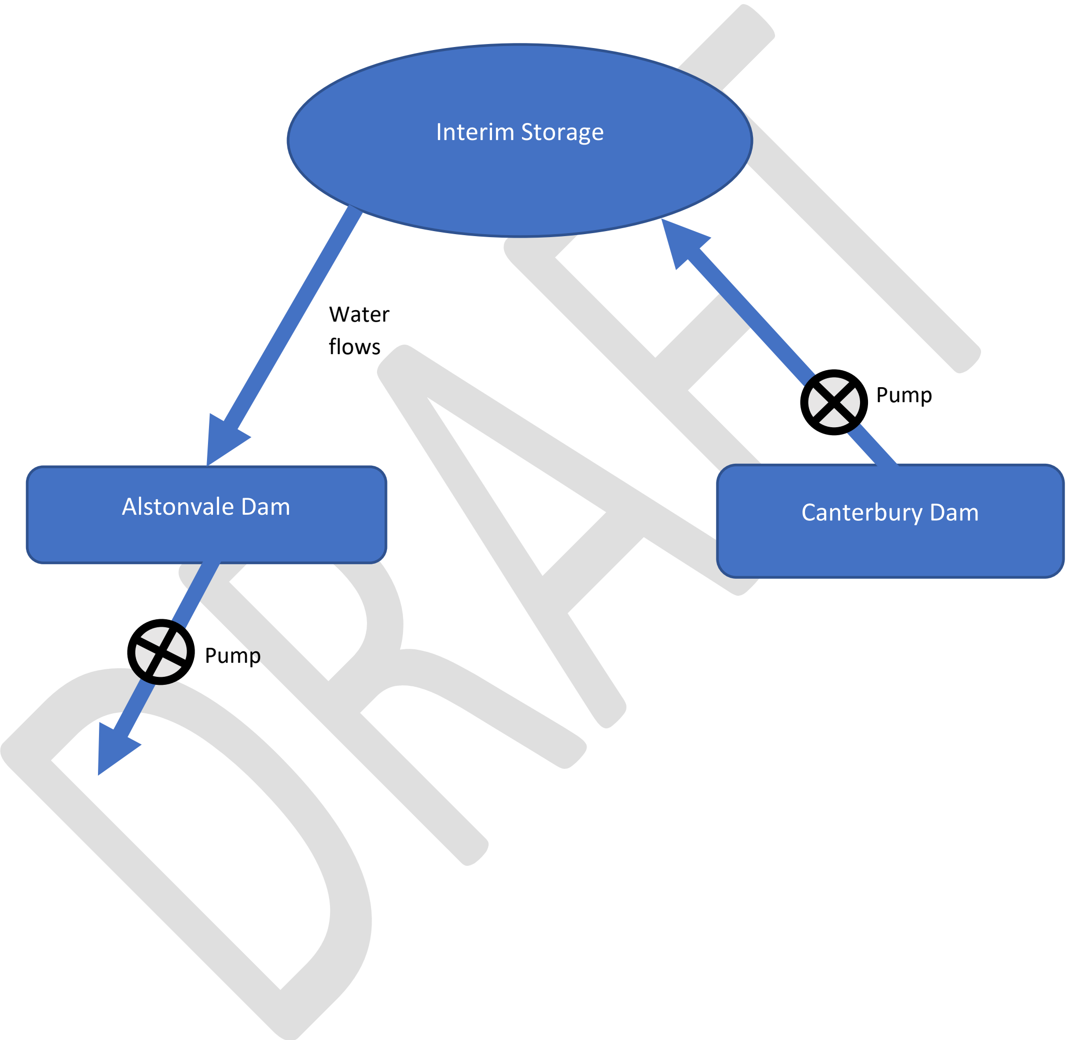
There is an option to add an additional generator at Alstonvale to allow the generation to be doubled if there are economic incentives to do so. The additional generation can be produced and exported at times of high market prices by:

1. Running the additional generator in parallel with the normal generator while there is sufficient water in the Interim Storage.
2. Turning off the pump at Canterbury pump station and maximising the export generation.

Capacity Requirements for Pumped Irrigation

The following diagrams outline the minimum and maximum infrastructure configurations contemplated in this report.

Minimum Infrastructure Schematic



Simple Electrical SLD – Minimum Infrastructure

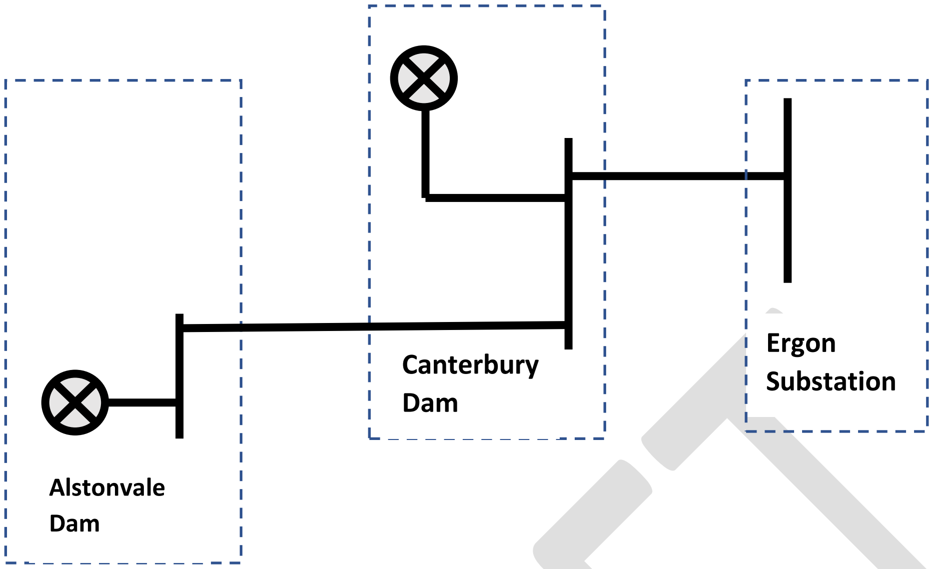


Table of Quantities – Minimum Infrastructure

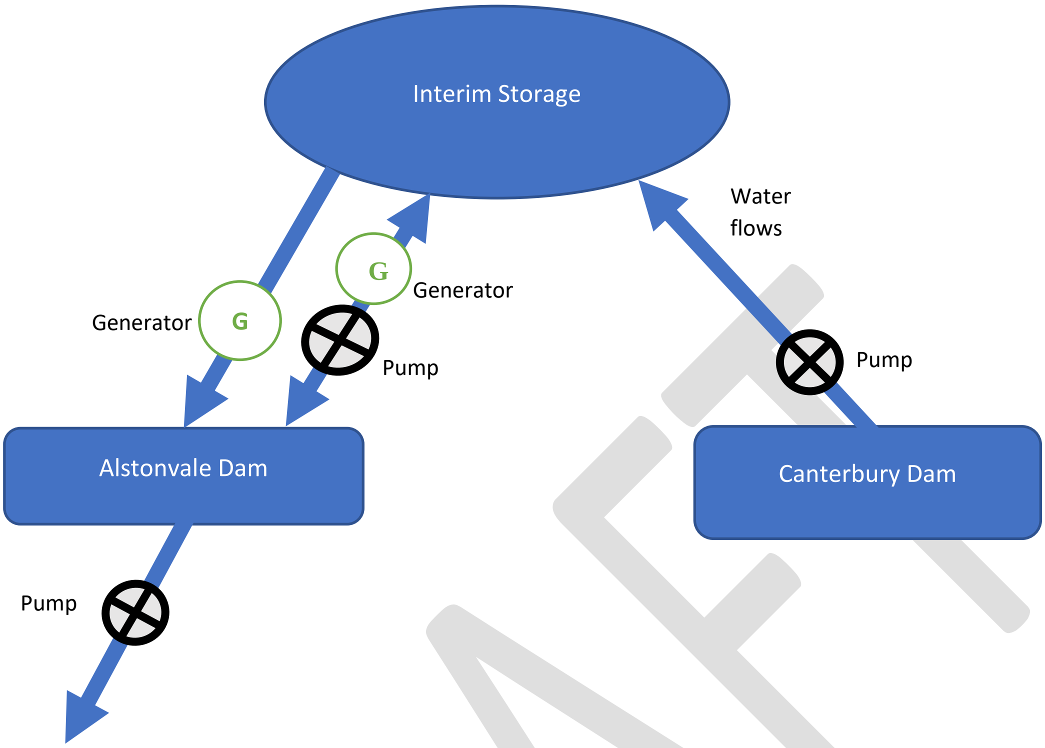
Item	Capacity	Energy[1]	Assumption
Pumping – Canterbury	7MVA	30,100 MWh	Operates for 4,300 hrs/yr
Pumping – Alstonvale Irrigation	3.5MW	22,700MWh	Assumes irrigation pumping for 6,500hrs/yr
Import from EECL	-(7+3.5) MVA	52,850 MWh	

Table 1: Minimum Infrastructure Requirements

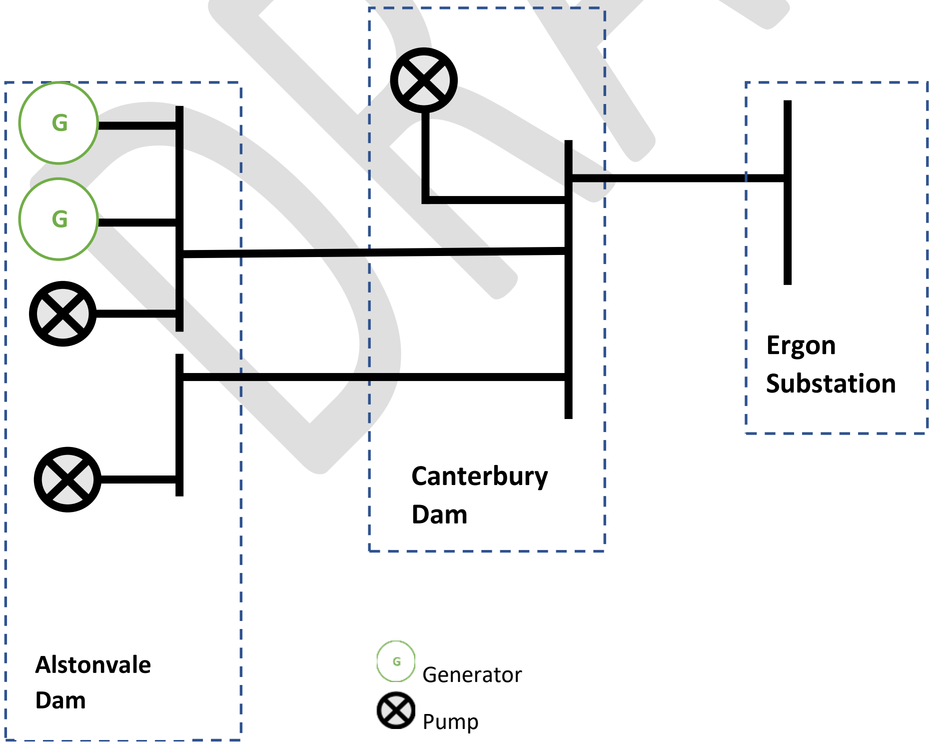
[1] The Demand is based on a kVA rating because that is the basis of charging for capacity from EECL; As a simplification, energy is assumed to be based on a pf of 1.0 for the pumps.

Maximum Infrastructure Scenario

Schematic – Maximum Infrastructure



Simple Electrical SLD – Maximum Infrastructure



Note under this scenario the capacity of the line from Canterbury Dam to Alstonvale generators would need to be reviewed to carry additional pumping load and/or generator output.

The potential scenario that maximises the energy component of the HIPCo development includes the characteristics as set out the table below.

Table of Quantities – Maximum Infrastructure Scenario

Item	Capacity	Assumption
Generator 1 – Alstonvale	2.7MW	Operates for same period as pumping load at Canterbury Dam (4,300hrs /yr) plus
Generator 2 – Alstonvale	2.7MW	Operates at periods of high electricity market prices based on 48 hrs of storage in the Interim Storage
Pumping – Canterbury	7MW	Operates for 4,300 hrs/yr
Pumping – Alstonvale irrigation	3.5MW	Assumes irrigation pumping for 6,500hrs/yr
Pumping – Alstonvale	7MW	Operates to re-fill Interim Storage out of wet season after generation – assumed to be 300 hrs/yr; this may have EECL tariff implications that need to be addressed
Import from EECL	7 MW	Makes up for pumping load not supplied by Alstonvale generator and assumed to be at low energy prices or Notified Prices. Kept to 4MW demand to keep network costs low. The demand from EECL for the additional pumping would need to be negotiated as special arrangement.
Export energy to EECL	5.4MW	Based on stopping pumping when market price is over $150/MWh Assumption is that Interim Storage has a capacity of 48 hours water storage to allow for energy market participation.

Regional Electricity Characteristics

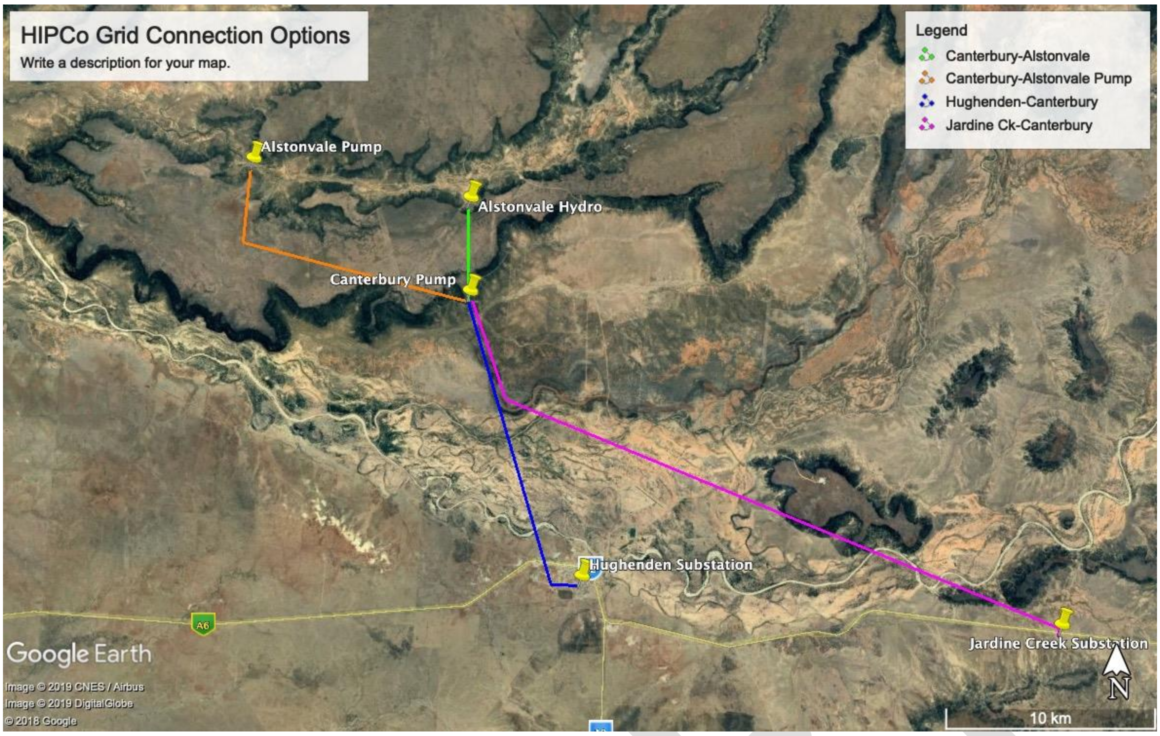
The electricity grid in the Hughenden area is supplied via a combination of 66kV and 132kV lines fed from Millchester substation near Charters Towers. There are two feeders supplying the area and the network is deemed to be ‘weak’ grid. Recently several significant renewable generation projects (e.g. Kennedy Energy Park) have been constructed in the region which has put constraints on the electricity network and there has been significant investment in grid stabilising equipment to help support the network.

There are two zone substations in the region being the Hughenden 66/33kV Substation and the Jardine Creek 132/66/33kV Substation adjacent to the Kennedy Energy Park. The Hughenden Substation consists of 2 x 66/33kV 7.5MVA transformers which have little spare capacity. The substation does not have any provision for additional 66kV or 33kV feeder bays. The Jardine Creek Substation consists of 2 x 132/66/33kV 40MVA transformers and has only recently been constructed. The substation has provision for 3 additional 66kV feeder bays.

In addition to the proposed pumping load for the HIPCo project, there is also other developments proposed for the region including an abattoir. A high level review of the electricity grid has been undertaken and has determined that the connection of the pumping load to the electricity grid shall be possible without significant investment in grid stabilising equipment. Extensive system studies and modelling are expected to be required by EECL as the Network Service Provider to allow the connection of this load to the electricity grid and will confirm the requirements for any grid stabilisation equipment. The cost of undertaking these studies will primarily be allocated to HIPCo as through the connection application process.

Connection Points

Through the conceptual analysis undertaken by WWA, four options for connecting the HIPCo pumps to the EECL grid were investigated. The options are detailed below along with a qualitative assessment with high level estimates of connection costs. The figure below shows possible line routes for the connection to the EECL grid.



Assumptions and disclaimer for high level cost estimates

1. These cost estimates have been prepared based on general assumptions with regard to technology, land access, regulatory and licencing and other development, construction and operational costs. Although every care has been taken, these estimates are only intended to give a general idea of the order of magnitude of likely capital costs.
2. Any works required at Hughenden Substation can be rebuilt on the existing site and won't require additional land procurement for relocation.
3. Supply to pumps will be at 11kV (lower voltages won't materially impact cost estimates)
4. 33kV line from Canterbury Dam to Alstonvale Dam pumps can be constructed as wood pole line
5. No additional grid stability devices (e.g. statcoms, synchronous condensers etc) will be required for connection to the EECL grid

132kV from new Jardine Creek sub at KEP

No detailed cost estimation was undertaken for this option as it does not provide any significant technical or operational advantage to the 66kV or 33kV connection options. The infrastructure required for connection will result in a materially higher cost than any 66kV or 33kV connection option and it has therefore been excluded from further consideration.

Scope of Works

The scope of work for this option is shown in the table below.

Item	Cost
132kV bay at Jardine Creek (KEP) substation	N/A
132kV concrete pole line from Jardine Creek to Canterbury Dam transfer pumps	N/A
132/33/11kV skid mounted substation at Canterbury Dam	N/A
33kV timber pole line from Canterbury Dam to Alstonvale Dam irrigation pumps	N/A
33/11kV skid mounted substation at Alstonvale Dam irrigation pumps	N/A

33kV from Hughenden Sub

Scope of Works

The scope of work and estimated cost is shown in the table below

Item	Cost ($M)
Upgrade of Hughenden 66/33kV substation including 2 x 20 MVA transformers	19.1
33kV concrete pole line from Hughenden Substation to Canterbury Dam transfer pumps	4.1
33/11kV skid mounted substation at Canterbury Dam	2.3
33kV timber pole line from Canterbury Dam to Alstonvale Dam irrigation pumps	0.7
33/11kV skid mounted substation at Alstonvale Dam irrigation pumps	2.3
TOTAL	28.5

Advantages

1. Lower cost for line construction to Canterbury Dam due to lower voltage
2. Lower cost for new substation at Canterbury Dam.
3. Shorter line route length compared with supply from Jardine Creek substation reducing likelihood of line failures from environmental impacts (e.g. lightning, impact from trees etc)

Disadvantages

1. Higher cost option compared with 66kV connections
2. Scope of Hughenden substation rebuild unknown thus increasing project risk
3. Longer construction time.

66kV from Hughenden Sub

Scope of Works

The scope of work and estimated cost is shown in the table below

Item	Cost ($M)
Upgrade of Hughenden 66kV bus to allow additional 66kV bay	5.0
66kV concrete pole line from Hughenden Substation to Canterbury Dam transfer pumps	5.6
66/33/11kV skid mounted substation at Canterbury Dam	3.5
33kV timber pole line from Canterbury Dam to Alstonvale Dam irrigation pumps	0.7
33/11kV skid mounted substation at Alstonvale Dam irrigation pumps	2.3
TOTAL	17.1

Advantages

1. Lowest cost option.
2. Lower expenditure required at Hughenden substation.
3. Shorter line route length compared with supply from Jardine Creek substation reducing likelihood of line failures from environmental impacts (e.g. lightning, impact from trees etc).

Disadvantages

1. Higher cost for line construction to Canterbury Dam compared with 33kV.

66kV from new Jardine Creek Sub at KEP

Scope of Works

The scope of work and estimated cost is shown in the table below

Item	Cost ($M)
66kV bay at Jardine Creek substation	1.0
66kV concrete pole line from Jardine Creek to Canterbury Dam transfer pumps	12.5
66/33/11kV skid mounted substation at Canterbury Dam	3.5
33kV timber pole line from Canterbury Dam to Alstonvale Dam irrigation pumps	0.7
33/11kV skid mounted substation at Alstonvale Dam irrigation pumps	2.3
TOTAL	20.0

Advantages

1. Less expenditure (and lower cost risk) on substation works required at Jardine Creek Substation to connect at 66kV compared to Hughenden substation.
2. Simpler connection to grid reducing risk of project delivery issues.

Disadvantages

1. Higher cost for line construction to Canterbury Dam compared with both other options supplied from Hughenden substation.
2. Slightly higher cost option compared with Hughenden 66kV connection.
3. Longer construction time for line route, but shorter construction time for substation circuit breaker.
4. Longer line route length compared with supply from Hughenden substation increasing likelihood of line failures from environmental impacts (e.g. lightning, impact from trees etc).

Hydroelectric Generation

There is an opportunity to offset some of the electricity consumption from the pumps by installing a small hydroelectric generator on the outfall pipe into the Alstonvale Dam. There is approximately 70m of head available between the small interim storage dam at the top of the escarpment and the outfall into the Alstonvale Dam. This would allow the installation of a 2.7MW generator (assuming minimal pipe friction losses). Other than the offsetting of electricity consumption, the hydroelectric generator would also provide the advantage of dissipating the energy from the water which will be required should the hydroelectric generator not be installed.

The connection of the hydroelectric generator will require additional investment. The cost to construct an 11kV line from Canterbury Dam to the Alstonvale Dam and install the hydroelectric generator would be approximately $4 - $6M. This cost would be offset against the expenditure required to install equipment to dissipate the water energy which would be approximately $600,000. This includes the installation of an 11kV line which would still be required to provide supply to the water energy dissipation equipment.

Summary of financial assumptions for economic analysis

Analysis suggests available capacity on EECL network is restricted to 10.5MW. This will allow the pumping from Canterbury Dam and from Alstonvale Dam into the irrigation system simultaneously. There will be significant gains to be made if the irrigation pumping can be staggered with the pumping from Canterbury Dam.

HIPCo will have the option of entering into a retail contract with Ergon Energy Queensland (EEQ) as the retail service provider for the purchase of electricity (as distinct from the cost of network access). This contract will combine the network charges from EECL (Ergon Energy Corporation Limited). It is assumed that Tariff 51A or 51B will apply depending on the voltage of the connection (66kV or 33kV) respectively. These are regulated tariffs and include a subsidy provided by the State Government and are therefore likely to be significantly cheaper than electricity purchased from other retailers.

Alternatively, HIPCo can pay the network charges to EECL directly and purchase its electricity from the market. This electricity market purchasing could be via another retailer (not EEQ) or directly from the wholesale market. Under these circumstances the network charges will be based on Network Tariff WC66T3 or WC33T3.

The rates for the Notified Prices (Tariff 51) and the Network Tariffs are revised every year and published.

The opportunity to improve the energy purchasing arrangements can be investigated including installation of a small hydro generator on the inlet pipes to the Alstonvale Dam as well as potential to purchase directly from one of the existing generators who have connections close to or at the potential EECL connection points for HIPCo.

The base case for the economic analysis should be the application of the EEQ Notified Price (Tariff 51) with both the Canterbury Dam pump and Alstonvale irrigation pump operating in parallel. The Tariff 51 charges should be between $0.20 and $0.25/kWh for the energy from the grid (20,000MWh/yr). A considerable amount of Tariff 51 charge is a fixed monthly charge (circa 25%) so the rate paid per unit of electricity delivered ($/kWh) will reduce the more the pumping is used.

Stakeholders

The stakeholders can be categorised into 3 distinct groups:

1. Provision of network services – EECL, Powerlink and land owners between the connection point and HIPCo
2. Electricity generation – Kennedy Energy Park, CS Energy, potentially others
3. Electricity retail services – EEQ, CS Energy, potentially others

A summary of relevant issues for each group is provided in the following sections.

Network Service Provider

The foundational assumption is that HIPCo will connect to the EECL network and hence EECL will have a Connection Agreement with HIPCo that allocates the costs of connection assets and then use of system charges. The use of the EECL network requires the use of the upstream transmission network owned by Powerlink Queensland. The relationship between EECL and Powerlink is highly regulated and the charging from both EECL and Powerlink is set annually and published by the Australian Energy Regulator.

EECL's connection processes are highly regulated with clear processes and obligations on both EECL as the NSP and connecting parties. HIPCo will need to make a strategic decision around the development of assets (unregulated assets) between its facilities and EECL's shared network. Broadly speaking there are two options for the development of unregulated assets, one in which EECL undertakes development on an unregulated basis and another where the connecting party takes the risk on developing the assets themselves.

EECL's connection processes may have long timeframes depending on the complexity of connection and the availability of resources. Timing of development of connection as well as land access for the construction of connection assets are a key risk for HIPCo.

Generation Stakeholders

There are two new generating facilities in the Hughenden area and there may be some value in dealing directly with them for the purchase of energy. This is considered a future opportunity and not considered in depth at this time. CS Energy has an off-taker agreement with the Kennedy Energy Park and this may allow HIPCo to deal with CS Energy as a pseudo generator.

Retail Services

There may be considerable opportunities for HIPCo to achieve value in the retail arrangements because of the unusual nature of the retail structure in Queensland and the nature of the HIPCo demand.

EEQ is the most obvious retail stakeholder and is the only provider of the Notified Prices in the region. It will be important to engage with EEQ but there are other energy purchasing options that need to be investigated. If HIPCo chooses to take a market contract rather than the Notified Price (Tariff 51), HIPCo will be able to purchase either from another retailer; this could be CS Energy who will have a vested interest in the load adjacent to the Kennedy Energy Park.

HIPCo can by-pass the retail market and purchase its electricity directly from the NEM wholesale market. Given the nature of the HIPCo load this may prove advantageous. The NEM structure allows HIPCo to move from a market retail arrangement to a wholesale arrangement relatively easily and HIPCo can return to a retail contract at any time. However, this exposes HIPCo to significant price risk due to the volatility of prices in the wholesale market.

Commercial Arrangements

Based on the commercial framework described in the Stakeholders section above, HIPCo will have 3 components of costs that make up the delivered electricity cost. The Market Costs component is small and regulated. The key to commercial value will be the commercial choices for energy and for network arrangements.

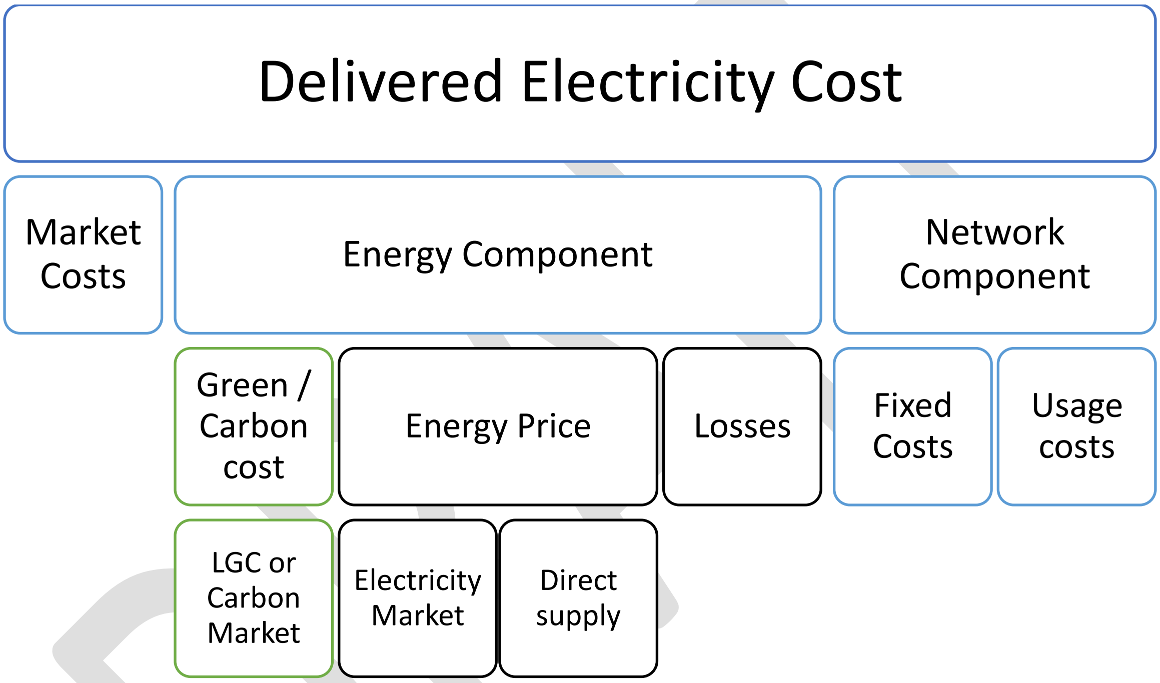


Figure 1: Framework for Delivered Electricity Cost

These cost components can be managed either by a Notified Price based contract with EEQ or a market contract. Notified Prices require less establishment and ongoing management costs (noting these are only a small part of the overall cost) and are more simple to implement and maintain.

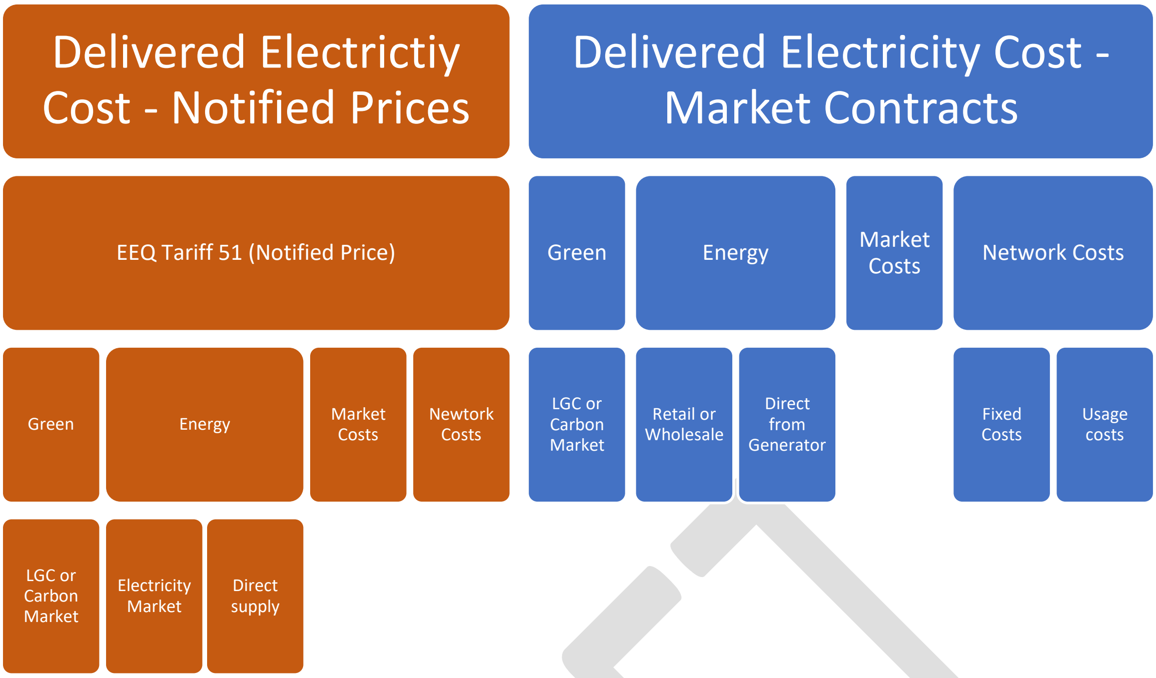


Figure 2: Electricity Purchasing Alternative Structures

For the purposes of this analysis it is assumed that the connection assets from the EECL connection point to the HIPCo pumps are treated as capital costs.

The simplest commercial arrangement is to enter into a retail contract with EEQ under Notified Prices and pay the appropriate tariff as determined by the Queensland Competition Authority. EEQ is only allowed to enter into retail contracts for supply based on these Notified Prices. Notified Prices represent charges that are normally less than the delivered costs from Market Contracts due to a subsidy provided to all regional Queensland customers by the State Government. The State pays this subsidy (referred to as the Community Service Obligation) to make up the difference in the actual cost of supply via market contracts and the Notified Prices.

A normal load in the mid-west would normally be better off under the Notified Price structure than a market contract. The HIPCo electricity demand requirement is unusual because of the seasonal nature of the demand and its size and hence a market contract arrangement could be more advantageous and should therefore be investigated in more detail.

Notified Price Outcome

The base case for this cost assessment is the Notified Price contract with EEQ. The Notified Price, set by the Queensland Competition Authority, is a delivered price that combines all the elements of the supply cost.

Tariff 51 is the appropriate existing Notified Price structure that will apply to HIPCo. Tariff 51A applies for 66kV connection and Tariff 51B for 33kV connection.

The table below shows the base case outcome for the pumping loads based on 6 months of pumping from Canterbury to Alstonvale Dams and 8 months of pumping from Alstonvale Dam to the irrigation system.

		66kV		33kV	
		2018-19	Forecast	2018-19	Forecast
Component	**Units**	**T51A**	**Annual Cost**	**T51B**	**Annual Cost**
Demand charge	$/kVA/mth	2.939	205,730	3.062	214,340
Capacity Charge	$/kVA	4.95	623,700	6.195	780,570
Excess Demand Charge	$/kVAr	4.899		4.899	
All usage	$/kWh	0.15452	8,166,382	0.15645	8,268,383
Connection Charge	$/day	11.089	4,047	11.575	4,225
Supply charge	$/day	278.36993	101,605	212.92965	77,719
TOTAL	**$/yr**		**9,101,465**		**9,345,237**
Rate	$/kWh		0.1722		0.1768
Fixed Costs	$/yr		729,353		862,514

Table 2: Comparison of Electricity Purchase Outcomes under Notified Prices – Tariff 51

Market Contract

HIPCo has the option of negotiating a market contract rather a Notified Price from EEQ. Under the Market Contract structure HIPCo is directly exposed to each element of the supply costs as shown in Figure 2 above.

The Network Charges under a Market Contract are regulated by the Australian Energy Regulator (AER) and published by EECL each year. The proposed network charges for a 66kV connection for HIPCo for 2019-20, based on the defined load and demand assumptions, are forecast to be approximately $3.18M as set out in table 3 below. This is the equivalent of $0.0704/kWh. This is a cost component of the delivered cost of $0.175/kWh under the Notified Price arrangement from EEQ.

Network charges for market contract Tariff WC66T3			
DUOS		**Rate**	**$/yr**
Connection	$/d	9.209	3,361
Fixed Charge	$/d	117	42,705
Capacity Charge	$/kVA ofAD/mth	10.586	1,333,836
Act Demand Charge	$/kVA/mth	5.641	355,383
Vol Charge	$/kWh	0.01046	472,269
Excess KVAR charge	$/kVAr/mth	4	
TUOS			
Fixed Charge	$/d	71.988	26,276
Capacity charge	$/kVa ofAD/mth	2.783	350,658
Vol Charge	$/kWhh	0.01312	592,368
Total network cost	**$/yr**		**3,176,856**
Effective network cost	**$/kWh**		**0.070362257**

Table 3: Components of Network Charges under a Market Supply Contract – Tariff WC66T3

The commercial strategy revolves around HIPCo being able to purchase its electricity and pay for losses and market costs for less than the difference between the Notified Price ($0.175/kWh) and the Network Price ($0.0704/kWh).

The opportunity is for HIPCo to purchase its energy for less than $0.100/kWh (or $100/MWh) to gain a commercial advantage.

Under the Market Contract structure HIPCo can purchase its electricity under a retail contract or directly from the wholesale market. The wholesale market price can be accessed via a retailer through "pool price pass-through" contract.

Access to the wholesale market price provides a good insight into the opportunity for HIPCo. The wholesale price varies every 30 minutes and can be very volatile. The table below shows the average annual Queensland wholesale price for the last full five years of the NEM.

Calendar Year	Queensland Average Wholesale Price ($/MWh)
2014	58.42
2015	52.52
2016	59.99
2017	93.12
2018	72.87

Table 4: Queensland Wholesale Electricity Price ($/MWh)

Green Energy Costs

The other major cost element is the "green" energy cost. Under current regulatory arrangements the "green" energy obligations are represented by the requirement to surrender Large Generator Certificates (LGCs) and Small-Scale Technology Certificates (STC) based on a proportion of the energy purchased. The LGC forecast price is currently about $35/LGC and the required percentage of LGCs required is approximately 20% of purchases. The STC price and percentage required such that they have a similar impact on the costs of electricity supply. It is prudent to allow between $10 and $12/MWh for the cost of "green" obligations in a market contract.

There is significant uncertainty about the future obligations for LGC/STC allocations. There is no shortage of sources of LGCs and STCs and hence unless there is significant increase in the regulatory percentage of energy that needs to be represented by renewable certificates the price will fall. There is a political risk that the renewable energy target will change and or there will be some form of carbon tax.

The cost impacts of any change will be seen in both market price outcomes and Notified Prices.

Market Contract Potential Outcome

The combination of the network charges under EECL network tariff WCT66C and a market contract should result in a delivered energy cost as set out below.

Cost Element	$/MWh	Comment
Energy Cost including losses	78	Based on wholesale market price exposure.
Network Use of System Costs	64	Based on EECL Regulated network tariff WC66T3.
Green Costs	12	Based on LGC market costs and Renewable Energy Target percentage obligations.
Other Market Costs	5	Including participant costs and FCAS exposure.
TOTAL	**160**	Higher level of risk of price fluctuations compared to Notified Price outcome.

Other Opportunities

The HIPCo operation has two major opportunities to improve the cost of electricity purchased for its pumping load. HIPCo could establish a lumping control system that allowed it to stop pumping when the wholesale prices become too high. This will allow HIPCo to manage the price volatility in the wholesale market and maximise the value of the electricity purchased. This will be a second order gain but can be very useful in protecting HIPCo from periods of high wholesale prices.

The second option for HIPCo is to investigate an electricity purchase arrangement directly with one of the local renewable energy generators in Hughenden. There is likely to be constraints on the export of the new generators into the EECL network because of the technical limitations of the EECL network in the area. If the physical connection arrangements can be structured to allow HIPCo to buy directly from the existing generators or via their connection point, it is possible to reduce the cost of some energy component to something in the order of $55/MWh. This will be a substantial gain over the retail or Notified Price outcome.

It is also possible to generate some electricity from the water flows into the Alstonvale Dam. This is discussed in the technical section above and could be in the order of 2.7MW of generation. The logical option is to allow this electricity off-set the amount of energy required to be purchased. This option may not be viable because of the installation costs of the hydrogeneration and further investigation will be required to inform an investment decision on this option.

Recommendations

It is recommended that the HIPCo investment decision process should adopt the following framework for assessment of the commercial impact of the electricity supply elements.

HIPCo should assume a capital cost of $20m to cover the following supply elements:

Item	Cost ($M)
66kV bay at Jardine Creek substation	1.0
66kV concrete pole line from Jardine Creek to Canterbury Dam transfer pumps	12.5
66/33/11kV skid mounted substation at Canterbury Dam	3.5
33kV timber pole line from Canterbury Dam to Alstonvale Dam irrigation pumps	0.7
33/11kV skid mounted substation at Alstonvale Dam irrigation pumps	2.3
TOTAL	20.0

Operating costs should be based on the Notified Prices and a 66kV connection offered by EEQ with the resultant cost of $9.1m/yr or $173/MWh consumed. The analysis should recognise the potential option of negotiating a market supply arrangement with a cost of $8m/yr or circa $160/MWh.

If the project economics are acceptable under these assumptions, then the next phase of work should be to further investigate and forecast the actual gains that can be achieved in lower energy purchasing through market price exposure and the additional capital costs and operating implications. A detailed study of the options for purchasing from the wholesale market should reduce the average delivered electricity cost by between 10% and 15% over a period of 5 years. This further work can also assess the economic potential for self-generation from the flows into the Alstonvale Dam.