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An Economic Feasibility Analysis on Pumped Hydro Energy Storage at Kidston and the Modelling of Co-located PV and Wind Integration

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Abstract

This economic feasibility analysis mainly focuses on analysing the commercial viability of a Pumped Hydro Energy Storage (PHES) system at Kidston, Queensland that operates as a merchant market participant in the National Electricity Market (NEM). In addition, it also investigates the effect of adding co-located PV and wind energy generators on the overall economics of the system. The primary method of analysis is computer simulation in which the annual profits are obtained based on AEMO aggregated price data, solar irradiance data and wind speed data, followed by the evaluation of the Net Present Value and the Internal Rate of Return to assess the profitability of the PHES/PV/wind system.

Firstly, the paper establishes the costing models for off-river PHES, PV plant and wind farm. It shows that the $282 million capital cost estimated by Genex Power closely aligns with the current PHES costing model. Next, the study shows that, when using PHES for electricity arbitrage, the Kidston PHES project is commercial feasible even without any co-located renewable energy generators. Furthermore, a number of scenarios are examined with different installed capacities of co-located PV and wind, and the results show that the colocation of PV and wind generally enhances the financial performance of the system. Then, the paper probes the scenarios of using PHES to minimise energy spillage, where it finds that, due to the stabilising effect of PHES, the system is able to support an installed capacity of PV and wind that is much larger than the transmission capacity without suffering major financial penalty and without serious energy spillage. Lastly, the effect of variable transmission capacity is briefly looked at, showing that a dynamic thermal rating can maximise the utilisation of the transmission infrastructure and significantly reduce energy spillage.

1. Introduction

In recent years, the rapid R&D in renewable energy industry and the increasing public awareness of energy sustainability, climate change and global warming have steadily reduced the cost of photovoltaics (PV) cells and wind turbines and, as a consequence, dramatically increased the number of large-scale PV plants and wind farms in Australia and around the globe.

While the renewable energy installed capacity continues to grow at an encouraging rate, it is also equally important to keep in mind that the nature of production of PV and wind energy is fundamentally different from traditional coal or gas fired power plants. The production of PV and wind energy depends entirely on the exogenous weather conditions, and in particular, solar irradiance and wind speed. The sun and the wind are intermittent energy sources as the energy harvested from them vary on their own and cannot be controlled.

As we strive to build a renewable future with most energy generated from PV, wind and other intermittent renewable energy sources, a power system must be able to handle such uncontrollable variations and supply electricity in a reliable fashion without being too costly. To this end, the power system will need to be integrated with large-scale energy storage systems that serve as buffers, such that excess energy from peak production can be stored and later put back to the grid when the power generated from renewable sources falls below the demand. This evens out random variations and brings stability to the power network.

Pumped Hydro Energy Storage is by far the most widely used large-scale energy storage method. According to Electric Power Research Institute, PHES accounts for more than 99% of large-scale energy storage capacity worldwide with a total generation capacity of around 127 GW as of 2012 (Rehman, et al. 2015). The advantages of PHES over other large-scale energy storage methods, such as battery, compressed air, and hydrogen, are the simplicity, cost-effectiveness and technology maturity. In addition, PHES has very high dispatchability in which it is able to start and generate power at full capacity within minutes or even seconds, making it a good choice for grid energy storage (FHC, 2016).

The principle mechanism of PHES is the conversion between electrical energy and hydro potential energy via reversible pumps. There are two types of PHES. An off-river PHES, or pure PHES, is characterised by the closed-loop water flow between an upper reservoir and a lower reservoir. In contract, an on-river PHES, or pumped-back PHES, relies on using water from a river or the sea. Our study focuses on the off-river PHES proposed by Genex Power in Kidston in Far North Queensland, which may become the first Pumped Hydro Energy Storage system to be constructed in Australia in more than 30 years.

2. Background Information

2.1. The Kidston Hydro and Solar Projects

The Kidston Hydro Project is a project being carried out by Genex Power that plans to build a PHES system using two existing pits at an abandoned gold mine at Kidston as the upper and lower reservoirs. The system will be connected to the National Electricity Market after project completion and then generate profit via electricity arbitrage, which is buying power from the grid at low price and selling power back to the grid at high price (Genex Power, 2015). At low price, the PHES will buy power from the grid for storage by pumping water from the lower to the upper reservoir. At high price, the PHES will generate and sell power by allowing water to flow downhill. The key enabler to electricity arbitrage is the fluctuating electricity price in the Queensland electricity market.

The original pre-feasibility study from Genex, as of December 2015, supports a proposal of a PHES generation capacity of 330 MW that uses three 110 MW reversible pumps. It has a total storage capacity of 1650 MWh. The two reservoirs are estimated to operate at 315-359 m and 522-529 m from sea level respectively, and the differential head is approximately 190 m on average. As of September 2016, Genex has announced the plan to expand the generation capacity to 450 MW with a total storage capacity of 2250 MWh (ARENA, 2016a). However, we shall continue to assume 330 MW generation capacity and 1650 MWh storage capacity as the PHES parameters in our study. Furthermore, the roundtrip efficiency is assumed at 80%, meaning that the PHES will have to buy 20% more energy from the grid to make up for the system loss during pumping and generation.

Genex estimates the total capital expenditure of the Kidston PHES project to be $282 million. This includes the build cost of a new 275 kV transmission line which estimates at $115 million. The new 160 km transmission line is proposed to extend from Kidston to the closest connection point on Powerlink's main 275 kV line, supplementing the existing 132 kV Kidston line. For the purpose of this study, it is assumed that the Kidston system uses only the 275 kV line. The maintenance cost is estimated at $4 million per year (Genex Power, 2015).

In addition to the 330 MW PHES, Genex also proposes to build a co-located PV plant with an installed capacity of 50 MW AC in the initial stage (Genex Power, 2016a). This is backed up by ARENA's Large-Scale Solar Photovoltaics program that provides Genex $8.85 million fund. In later stage, the co-located PV plant will be expanded to 150 MW AC capacity after the completion of the planned 275 kV transmission line (Genex Power, 2016b). The 50 MW solar plant has additionally been awarded a 20-year Power Purchase Agreement (PPA) with the Queensland Government at an indicated price somewhere between $80-100/MWh as of September, 2016 (Genex Power, 2016c). The actual number has not been disclosed. For most of this study, it is assumed that the system uses NEM spot price, that is, there is no fixed price for energy, and Genex buys and sells electricity according to pool prices.

2.2. AEMO and NEM

The Australian Energy Market Operator (AEMO) runs the National Electricity Market based on the National Electricity Rules (NER). In the context of electricity trading and wholesaling, the NER defines the bidding process by which individual power generators in NEM must obey. In essence, NEM can be described as a wholesale spot market, where individual power plants as bidders must put forth their bid prices at noon on the previous day in order to compete for electricity wholesaling on the next day. AEMO will then accept bidders, from the lowest bid price, up to a point where the demand can be fulfilled for a given half-hour. After deciding the bid winners, the highest price of all the winning bid prices will be offered to all the winners. This process occurs on a half-hourly basis, and the price is in fact an aggregation of six prices on a 5-minute interval during that half-hour (AEMC, 2016).

2.3. Cost Models of PHES, PV and Wind

The PHES cost parameters are based on Genex pre-feasibility study. In addition, the capital cost will be verified against a generic PHES costing tool developed by Chris Lowe with the original cost inputs from Roger Fulton[1] (Lowe, 2015). This model takes account of system parameters such as generation capacity, transmission line length, road length etc. as well as PHES-specific parameters like roundtrip-efficiency, gross head etc. The lifetime of the PHES system is assumed to be 50 years, which is based on another study on a comprehensive PHES component inventory (Torres, 2011).

Similar to a PHES project, PV and wind projects are also capital intensive. A large-scale PV plant typically has a capital cost of $1800/kW DC, which is obtained from the ARENA Large-Scale Solar program (ARENA, 2016). A large-scale wind farm typically has a capital cost of $2300/kW according to the ACT reverse auctions index by CPI of the contract price (ACT Government, 2016). This study assumes that the co-located PV and wind generators also operate as merchant market participants in NEM. More specifically, the profit earned by generating 1 MWh of PV or wind energy is the sum of the pool price per MWh and the price of one Renewable Energy Certificate (REC) that assumes at $40. Lastly, the discount rate is

[1] Roger Fulton is an experienced hydro engineer.

assumed at 5%, and the operation and maintenance (O&M) costs are deducted from the profit. A full summary of the cost parameters and assumptions is given in Table 1.

Table 1. Cost inputs of PV, wind and PHES

	Capital Cost	Fixed O&M (per year)	Variable O&M	RECs ($/MWh)	Lifetime (years)	Real Discount Rate
Single-axis tracking PV	$1800/kW DC	$36/kW (2% of cap.)	0	40	25	5%
Wind	$2300/kW	$35/kW	$10/MWh	40	25	
PHES	$282 million	$4 million	0	0	50	

Profitability is quantified by the Net Present Value (NPV) and Internal Rate of Return (IRR). Both take consideration of the time value of money. The NPV is the present value of the net cash flow at a particular discount rate compared to the initial capital investment, while the IRR is simply the discount rate at which the NPV is zero. A profitable project is indicated by a positive NPV or an IRR above the discount rate. It is notable that the NPV directly measures the net cash flow but does not consider the project size, while IRR shows the return on the original money invested but may give conflicting results from NPV for two mutually exclusive projects.

2.4. Data Acquisition of Renewable Resources

To simulate scenarios of co-located PV, the hourly solar irradiance data at Kidston is extracted from the gridded hourly solar DNI & GNI data produced by the Bureau of Meteorology (BoM). NREL's System Advisor Model (SAM) uses the hourly data to simulate the power output using a single-axis tracking PV array with a nameplate capacity of 2 MW DC.

Half hourly wind speed data are acquired from a nearby weather station in Georgetown that locates approximately 90km north-west of Kidston. The data are then linearly adjusted using the average wind speed obtained from the Australian Renewable Energy Mapping Infrastructure (AREMI) for a desired wind farm location 40 km west of Kidston at a hub height of 100 m. The average wind speed is found to be 9.57 m/s from AREMI. This produces a set of half-hourly, linearly-adjusted wind speed time series, which can then be used to extract the power output based on the power curve of a Vestas 3.0 MW wind turbine.

2.5. Power Transmission

One important constraint of the Kidston system is the capacity of the 275 KV single-circuit "sulphur" AAAC transmission line. For most analysis in this paper, the transmission capacity is assumed to be fixed at 330 MW. A more sophisticated model is given in Section 7.

3. Capital Cost Estimation

According to Lowe's model, the PHES capital cost consists of direct cost, road cost, transmission cost and contingency. The road cost is zero as Kidston has direct road access, and the transmission cost is $115 million as estimated by Genex. The 16% contingency is derived from Lowe's study on Araluen pumped hydro scenario (Lowe, 2015).

Table 2. Capital cost breakdown of Kidston PHES

	Model/Assumption	Inputs	Cost
Direct Cost	Plant cost: $3.3657 \times PC^{0.891} \times H^{-0.336} \times 1.25e6$ (PC – power capacity, H – head)	PC: 330 MW H: 182 m	$128 million
	Penstock cost: $27.4e6 \times L$ (L – length of penstock)	L: 700 m	$19 million
	Reservoir cost: existing mine pits	-	0
	Water first fill: $10/ML	4560 ML	~0
Road Cost	Existing road	-	0
Transmission Cost	$0.72 million/km	160 km	$115 million (by Genex)
Contingency	16% of Direct Cost	-	$24 million
Total	**-**	**-**	**$286 million**

The above estimate on the capital cost closely aligns with Genex estimate of $282 million. Hence, it is reasonable to use $282 million for the rest of the analysis in this paper. In addition, the desired location of a co-located wind farm is 40 km away from the PHES. Given that the capital cost of $2300/kW already considers 10 km transmission line, a co-located wind farm incurs an additional transmission cost of $21 million to cover the remaining 30 km.

4. Electricity Arbitrage using PHES

As Kidston PHES relies on the fluctuations of QLD electricity price to make profit, it is possible to devise a PHES arbitrage scheme purely based on empirical observations of historical price data. In fact, Genex has identified that the financial success of the Kidston Hydro Project largely depends on the fact that cheap electricity can be purchased "between the hours of 12.00am and 6.00 am", which can then be sold back to the grid at high price "between the hours of 1.00pm and 8.00pm" (Genex Power, 2015). By analysing AEMO historical aggregated price data, it can be observed that the highest pool price usually occurs between 4-6pm and the lowest pool price between 3-4am. Therefore, we can set a fixed trading window that operates PHES at fixed time of a day, namely, 2:30-7:30pm for selling and 1:00-6:00am for buying. The annual profits from 2005 – 2014 using this strategy are obtained from the simulation and shown in Figure 1.

The annual profit on average is found to be $20 million after inflation adjustment using historical inflation rates. This profit has considered the $4 million O&M cost. From Figure 1, it is evident that the standard deviation, which quantifies pool price fluctuations, is highly correlated with the annual profit. A larger standard deviation in pool prices generally leads to a higher profit, verifying Genex statement that the success of the Kidston project is largely dependent on the pool price fluctuations (Genex power, 2015). In addition, it reflects the high variability of the annual profits in different years, which translates to a higher uncertainty.

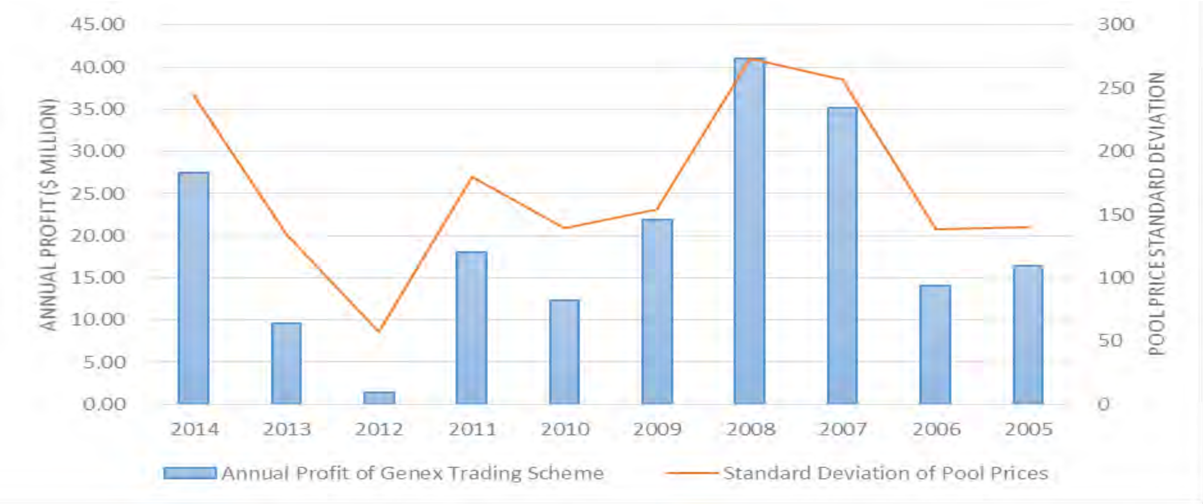

Figure 1: Genex trading window profit and pool price standard deviation

After determining the capital cost and the long-term average of the annual profit, the profitability can be quantified by assuming the same annual profit for the entire lifetime of the PHES system. A discount rate of 5% yields a corresponding NPV of $78 million, indicating that the system is financially profitable. The IIR is calculated as 6.7%, which is rather low for an investment. It means that the project will not be financially feasible if the discount rate is higher than 6.7%.

However, it should be noted that this scenario uses the simplest and most conservative trading method that does not utilise any real-time feedback. Further investigations show that the financial performance can be significantly enhanced by implementing more sophisticated trading strategies that observe and establish correlations between electricity price and other predictable variables, such as weather and meteorological conditions, electricity supply and demand, competitor operability (which may be influenced by fuel prices for coal and gas power plants and by water levels of hydroelectric generators) etc.

5. Adding Co-located PV and Wind

A number of scenarios of PHES, PV and wind are simulated with the aim of determining the effect of adding renewable energy generators to the Pumped Hydro system at Kidston. An important assumption in this section is the fixed transmission capacity of 330 MW. Furthermore, the PHES is operated based on Genex window strategy discussed previously.

5.1. Solar and wind resources at Kidston

Using the data and methodology discussed in Section 2.4, the wind and solar resources at Kidston are analysed and summarised in Table 3 below. The Spearman correlation of 0.2477 shows a slightly positive correlation between PV and wind. As a side note, the AEMO's data for their 100% renewable energy study suggests a negative correlation.

Table 3. Solar and wind resources at Kidston

PV (dc) Capacity Factor	Wind Capacity Factor	Average Wind Speed at 100	Spearman correlation
25.7%	60.6%	9.57 m/s	0.2477

5.2. Simulation algorithm

To simulate scenarios with PV and wind collocation, it is important to consider their dynamic interactions between three things – PV/wind, PHES and NEM. These interactions are governed by individual system parameters, such as installed capacity and storage capacity, as well as system constraints, such as transmission capacity. The high level dynamics of the system can be captured by the following algorithm that can be executed in a computer program with a time step of 0.5 hour.

1. The energy generated by PV and wind is first sold directly to the NEM grid where possible.
2. If the transmission line becomes saturated, any remaining PV and wind energy will be sent to the PHES. Notably, RECs should be added to the system profit for this energy, because PHES and PV/wind are metered separately. It can be viewed as two distinct processes. The PV/wind plants first sell energy to NEM at the pool price plus RECs price, and then PHES buys that energy at the same pool price.
3. If the transmission line is not saturated, PHES may use remaining transmission capacity for electricity arbitrage. In this case, PHES is allowed to continue to sell power until 1:00am due to the fact that addition of PV and wind reduces transmission availability. However, it may purchase power at the full capacity of 330 MW because the direction of the power flow is the opposite (i.e. negative).

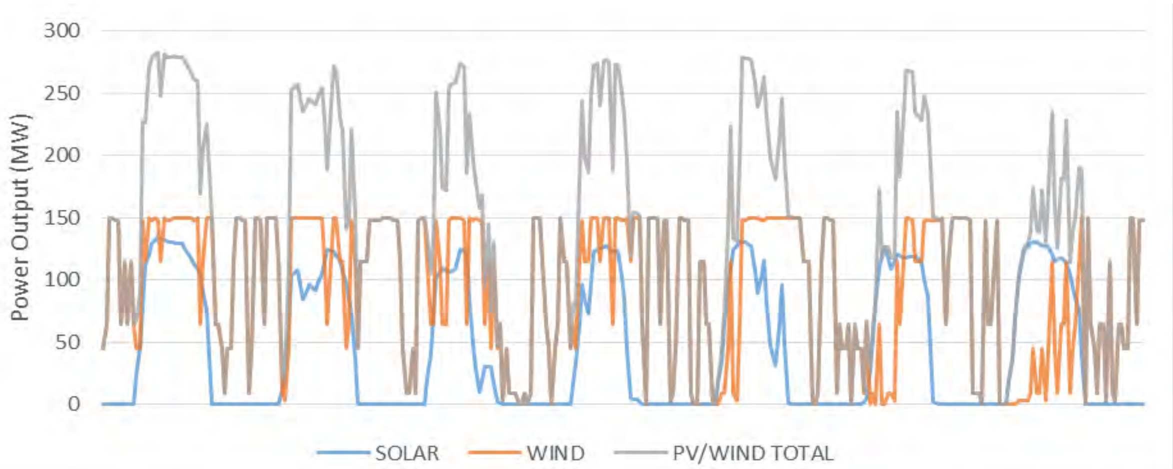

Figure 2: PV and wind production in a typical week at Kidston

Figure 3: PHES arbitrage pattern in the same week as Figure 2

Figure 2 shows the PV and wind power output in a typical week at Kidston with 150 MW wind and 150 MW PV. The PV power output peaks at noon and drops to zero at night, while the wind power output has no clear pattern. Due to Kidston's latitude, the wind and solar resources have little seasonal variations.

The PHES arbitrage process is clearly illustrated in Figure 3. It can be observed that the presence of the 330 MW transmission capacity has a huge impact on how PHES carries out arbitrage. In the previous simulation in Section 4, PHES can buy and sell power at the full capacity of 330 MW. After adding co-located PV and wind, it is still able to buy power at 330 MW because of the opposite direction of power flow. However, generating and selling power are now greatly restricted, as the PV and wind energy produced from co-located plants uses a significant portion of the transmission. As a result, PHES cannot sell power at maximum capacity when the electricity price peaks in the afternoon, and this decreases the performance of PHES for electricity arbitrage.

5.3. Results and discussion

Table 4 summarises the simulation results with a number of selected scenarios. The PHES generation capacity remains at 330 MW and the transmission capacity is fixed at 330 MW. Note that the profit and energy production are on a 'per year' basis, averaged from 2005 – 2014. The profits are inflation-adjusted by historical rates, and all monetary values are in 2016's values. In addition, the discount rate is assumed at 5% for NPV. The GWh energy produced includes potential spilled energy.

Table 4: Co-located PV and wind (fixed 330 MW transmission)

PV Capacity (MW)	Wind Capacity (MW)	Capital Cost ($million)	Profit ($million p.a.)	NPV ($million)	IRR (%)	Energy Produced (GWh p.a.)	Trans. Line CF (%)
0	0	282	20	78	6.7	0	42
50	0	370	30	147	7.5	113	46
100	0	460	40	215	8.0	225	49
200	0	640	60	344	8.5	450	57
300	0	820	78	437	8.6	676	65
500	0	1180	104	453	7.7	1130	78
0	50	420	42	306	9.6	259	51
0	100	530	62	534	11.3	518	60
0	200	760	100	925	12.7	1040	77
0	300	990	136	1280	13.2	1550	88
0	500	1450	162	1160	10.3	2590	90
50	50	510	51	371	9.6	370	55
100	100	710	80	634	10.7	740	67
150	150	920	108	863	11.1	1110	80

Firstly, it is important to observe that the addition of co-located PV and wind generators generally enhance the financial performance of the system. The original IRR is 6.7%, but with co-location of renewable generators, the IRR can be significantly increased to as high as 13.2%. Secondly, we can see that the financially optimal installed capacity for co-located PV or co-located wind is 300 MW, beyond which the system will spill energy due to the limited transmission capacity. Furthermore, it is clear that wind outperforms PV at Kidston. The capacity factor of wind is much higher than that of PV despite having a higher capital cost and higher O&M costs. A co-located wind farm has a much higher IRR than a co-located PV farm with the same installed capacity.

Finally, it is also notable that, despite a 330 MW transmission capacity and a PHES installed capacity of 330 MW, the spilled energy (omitted from the table) is still very large for a system with less than 660 MW of PV/wind installed capacity. This is because PHES is used for electricity arbitrage in these scenarios, not for minimising energy spillage.

6. Minimising Energy Spillage

So far PHES has been used for electricity arbitrage in which it buys and sells electricity during designated hours to fill or empty its storage. However, PHES tends to be seriously under-utilised in a system with large installed capacity of PV and wind.

In this section, the PHES is used to minimise spilled energy. Therefore, it will store any spilled energy if the storage is not full, and it will also try to empty the storage as soon as opportunity arrives, that is to say, it will sell electricity when there is any available transmission capacity. The results are summarised in Table 5 below.

Table 5: Using PHES to minimise energy spillage (fixed 330 MW transmission)

PV Capacity (MW)	Wind Capacity (MW)	Minimise energy spillage			Arbitrage		
		Energy Spilled (GWh p.a.)	NPV ($million)	IRR (%)	Energy Spilled (GWh p.a.)	NPV ($million)	IRR (%)
300	0	0	60	5.5	0	437	8.6
400	0	0	199	6.4	9	515	8.5
500	0	0	320	6.9	175	454	7.7
600	0	0	434	7.3	485	270	6.4
700	0	26	508	7.3	849	42	5.2
800	0	175	462	6.9	1240	-206	4.1
0	300	0	1030	11.7	0	1280	13.2
0	400	43	1410	12.5	349	1350	12.2
0	500	414	1500	11.8	1040	1160	10.3
200	200	0	833	9.9	39	1050	11.1

The most obvious observation is that the presence of a 330 MW PHES allows the co-located PV/wind to have a much higher installed capacity without suffering major financial penalty. In addition, the results also show that the twin goals of maximising financial performance and minimising spilled energy cannot always be satisfied at the same time. For instance, a 400-500 MW PV plant may achieve better financial performance with the arbitrage method or achieve minimum spilled energy with the minimising spillage method, but not both. This illustrates that a tension may sometimes exist between financial performance and energy spillage management.

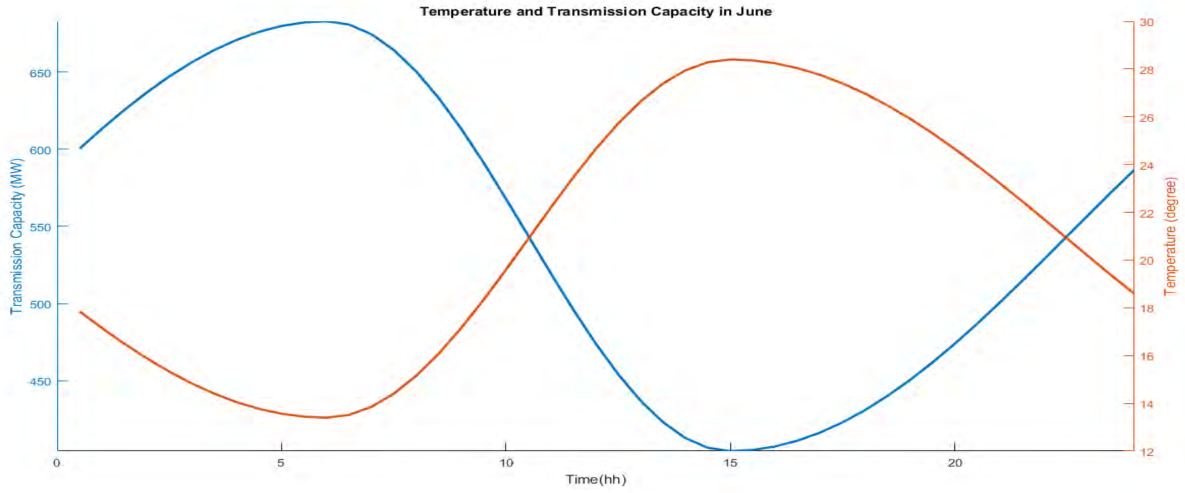

Figure 4: Daily transmission capacity and temperature variations at Kidston in June

7. Variable Transmission Capacity

A more complex model of the transmission capacity of a short-distance overhead line takes account of the thermal limit (Hu, et al., 2015). In this case, the advantage of using a dynamic thermal rating over a static thermal rating is the better utilisation of transmission capacity but at the expense of more complex monitoring process (Hosek, 2011). From the specification of a typical "AAAC" transmission line, the continuous current carrying capacity varies from 623 A to 1650 A when the ambient air temperature varies from 35°C to 10°C (Olex, 2012). Assuming a power factor of 0.95, the transmission capacity of a 275 kV line is therefore 282 MW at 35°C and 746 MW at 10°C. Knowing these two points, we can then use linear interpolation or extrapolation to approximate the capacity for any air temperature.

The Georgetown's monthly long-term averaged maximum and minimum temperatures are used to model the temperature variation. More specifically, the long-term averaged maximum temperature is assumed to occur at 3pm, and the minimum temperature occurs at 6am. Then, we apply two sine curves to fit through these two points to get the approximate daily temperature variation. For example, Figure 4 shows the transmission capacity and temperature in a typical day in June. Note that the transmission capacity could be as low as 250 MW when the air temperature reaches 36.6°C in November.

Again, a number of scenarios are simulated and the PHES uses the arbitrage method. The results are shown in Table 6 below, which can be compared against the fixed transmission capacity scenarios in Table 4.

Table 6: Co-located wind and PV plants (variable transmission, pool price + RECs)

PV Capacity (MW)	Wind Capacity (MW)	Capital Cost ($million)	Profit ($million p.a.)	NPV ($million)	IRR (%)	Energy Produced (GWh p.a.)	Energy Spilled (GWh p.a.)	Trans. CF (%)
0	0	282	18	47	6.1	0	0	15
50	0	370	27	94	6.6	113	0	17
150	0	550	45	197	7.4	338	0	19
300	0	820	74	366	8.0	676	0	24
500	0	1180	104	454	7.7	1130	112	29

PV Capacity (MW)	Wind Capacity (MW)	Capital Cost ($million)	Profit ($million p.a.)	NPV ($million)	IRR (%)	Energy Produced (GWh p.a.)	Energy Spilled (GWh p.a.)	Trans. CF (%)
0	50	420	38	233	8.5	259	0	19
0	150	650	79	684	11.7	777	0	25
0	300	990	135	1260	13.1	1550	9	33
0	500	1450	184	1570	12.1	2590	520	39
50	50	510	47	282	8.6	372	0	20
150	150	920	106	832	10.9	1110	0.2	29
300	300	1530	167	1159	10.1	2230	420	39

The transmission line capacity generally drops by more than half when adopting variable transmission capacity, illustrating the noticeable advantage of a dynamic thermal rating that fully utilises the potential of an overhead transmission line. In addition, the spilled energy is decreased significantly for co-located PV or wind with very large installed capacity.

However, it can be observed that, for an installed capacity of 300 MW or less, the system generally suffers a decrease in IIR by 0.5% or so, along with the decreases in annual profit and NPV. This suggests that our previous assumption of a 330 MW fixed transmission capacity might be too generous. At summer noon, the transmission capacity of the 275 kV line would not be able to cope at 330 MW. In reality, the 275 kV line will be used to enhance the existing 132 kV line, and the fact that Georgetown draws power from the opposite direction should further ease the load on the transmission infrastructure.

8. Conclusion

The study shows that the Pumped Hydro Energy Storage at Kidston is economically feasible as a merchant market participant even without co-located PV and wind. The Internal Rate of Return is found to be 6.7% with the simplest window trading algorithm, which can be significantly improved with more complicated NEM arbitrage strategy.

Furthermore, the integration of co-located PV and wind generators can greatly enhance the financial performance of the system. The optimal combined installed capacity is found to be 300 MW with the Internal Rate of Return ranging from 8.6-13.2%.

In addition, we have also identified some tension between using PHES for financial gain and using PHES for minimising energy spillage. Lastly, it is found that a variable transmission capacity realised by a dynamic thermal rating can greatly reduce energy spillage when the installed capacity of co-located PV and wind is very large.

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