Does a Barassi Line exist to divide CSP-MED and PV-RO in Australia?

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Introduction

Australia has the *lowest* average annual rainfall (just 470mm) of any inhabited continent. To make matters worse, the arid parts of Australia receive less than 200mm a year, representing a significant challenge to sustainable growth for the Australian economy [1]. The Australian target to achieve net zero emissions by 2050 has been silent on sustainable sources of water for this energy transition [2]. As part of this net zero plan, Australia hopes to become a renewable energy exporter via the production of green hydrogen [3]. Hydrogen production via electrolysis requires 30-50 kg of fresh water for every 1 kg of hydrogen [4]. In addition, photovoltaics require water during their production and for cleaning [5]. This means energy and water are inextricably linked (i.e., the energy-water nexus). The obvious—but not straightforward—solution to this is to cogenerate electricity and water.

While many possible configurations exist for sustainable cogeneration, 2 near-term, potentially large-scale stand-out options: a solar thermal pathway and a solar electric pathway. Integrating a desalination process with a concentrating solar thermal power (CSP) plant can be achieved by recovering the waste heat from the CSP plant's turbine and directing it towards a thermal desalination process, such as multi-effect distillation (MED). Although this integration point is energetically favourable, it is important to check whether it is cost-effective as the turbine back pressure must increase to provide enough higher quality waste heat (i.e., temperature above 60℃) [6]. Furthermore, since CSP plants operate effectively at locations with higher average annual direct normal irradiance (DNI), they are usually installed away from coastlines. This is unfavourable for desalination plants as they must be positioned near the sea to avoid water pumping costs. Thus, this inverse correlation of high DNI resources and the proximity distance to the coastline is important to investigate to determine the feasibility of such cogeneration plants. For example, a 0.6 $\mathrm{kWh/m^2 day}$ of additional DNI is required to offset each 100 km of pumping energy to maintain the same payback period in the New South Wales state [7]. An alternative to this is to couple a photovoltaic (PV) farm with a reverse osmosis (RO) system. Stand-alone PV and stand-alone RO systems have enjoyed high commercial adoption as both are the leading technologies in their fields [8, 9]. In addition, the coupling of these two technologies is favourable as the PV system can be installed in locations with high solar insolation, and the electricity generated is transported via the grid to the coastline RO plant. Whereas CSP and MED co-depend on each other as the waste heat from the CSP turbine is required to operate the MED system, and the MED system acts as the power block's heat sink. Thus, this dependency may not gain commercial attraction compared to PV-RO among investors.

To date, no study has investigated the feasibility of CSP-MED compared to a decoupled PV-RO. A techno-economic model alongside a site feasibility analysis was conducted to determine where in Australia each integration is more feasible. The selected sites focus on providing electricity and freshwater to transition from coal production to green hydrogen electrolysis production.

Methods

A techno-economic analysis was conducted on CSP-MED and PV-RO to determine which configuration can better utilize Australia's sun and cogenerate electricity and water. Since the centre of Australia is uninhabited, a 300km buffer from the coastline is studied. To ensure a fair comparison between CSP-MED and PV-RO, the CSP-MED system was analysed first at a given site to determine the amount of waste heat from the turbine, which will then decide on the MED production capacity. Based on the freshwater capacity and the electricity generated by the CSP plant, the PV-RO system is designed to have the same power capacity and freshwater production. In this study, a 50 MWe CSP capacity with 6 hours of thermal storage with a waste heat temperature of 70℃ was used, as it provides high-quality waste heat (~69 MWth) which when recovered by the MED process, can produce ~27,000 $\mathrm{m^3/day}$ at a capacity factor of ~36% [6]. This 50 MWe capacity and the ~27,000 $\mathrm{m^3/day}$ are then the inputs to the PV-RO system model.

A validated MATLAB code was developed to model the MED major components (i.e., evaporators, preheaters, and flashing boxes) by solving the mass, energy, and salt balances with heat transfer fundamentals [7]. A conventional parabolic trough CSP plant is considered in this study and modelled by the Parabolic trough – physical – power purchase agreement – single owner model in the System Advisor Model (SAM) developed by the National Renewable Energy Laboratory (NREL). Downstream, a relatively standard inter-stage regenerative feedwater heater Rankine cycle is used as a power block. For the PV-RO configuration, the RO configuration was modelled using Dupont's Water Application Value Engine (WAVE) and the Power Model Pro tool by Energy Recovery Inc.. The PV system was modelled using the PVWatts-battery – distributed – commercial owner model in the SAM software, and the REopt tool was used to optimize the battery capacity that provides the minimum levelized cost of electricity.

After modelling these 2 configurations, a geographic information software system (QGIS) was used to perform a site-specific analysis considering climate conditions (i.e., DNI, ambient temperature, and wind speed), land topography, seawater conditions (i.e., seawater temperature and salinity), and proximity to seawater [10]. The latter variable is not considered for the PV-RO configuration as the RO process is installed on the coastline, unlike the CSP-MED system.

Results

Under nominal conditions, Figure 1 presents the CSP-MED and PV-RO payback period under different DNI conditions and distances from the coastline (for CSP-MED). There is no doubt that the distance between the coastline and the CSP-MED plant would influence the cost of water. However, it is interesting that at locations with high DNI resources, the effect of the proximity to the coastline is reduced. For example, Figure 1 shows a ~57% increase in the plant's payback period at low DNI locations (i.e., $4\ \mathrm{kWh/m^2day}$) when moving the plant's location 300 km inland. Whereas there is a ~30% increase in the payback period at higher DNI locations (i.e., 8.5 $\mathrm{kWh/m^2day}$) when going inland at that same distance. This shows that it is far more important to locate these solar-driven systems in higher DNI locations than locations closer to the coastline.

On the other hand, Figure 1 shows that integrating a CSP system with a MED is unfavourable compared to a decoupled PV-RO system. It is shown that the payback period of PV-RO systems is under ~10.5 years even when locating the PV farm at sites with low DNI resources of $4\ \mathrm{kWh/m^2day}$. This is not surprising due to the low capital and operating costs of PV and RO systems compared to CSP-MED systems. However, a question is raised on whether the cogeneration of electricity and water gives an edge to PV-RO over CSP-MED. As described in the method followed, the PV-RO system is designed to cogenerate the same amount of electricity and water as the CSP-MED. However, if the investor is more focused on making freshwater using solar energy, then there is no need to oversize the PV farm. Instead, the PV farm would be designed to provide *just* enough electricity to run the RO plant. This was plotted in Figure 1 and, *yet*, PV-RO was shown to be more cost-effective than CSP-MED, although the latter makes electricity and water using the same infrastructure. Furthermore, when compared with the PV-RO cogeneration plant, the PV-RO water production-only system has a lower payback period at sites with DNI lower than 5.5 $\mathrm{kWh/m^2 day}$. This is explained by the economies of scale, where it is better off in cogenerating electricity and water at locations with higher DNI as the capacity factor of those systems is larger.

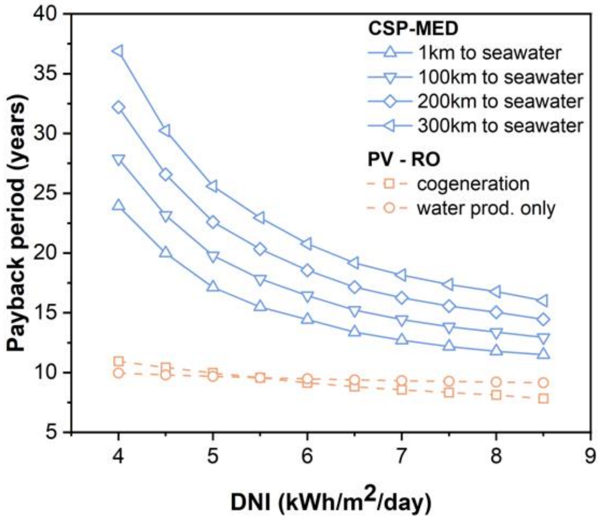
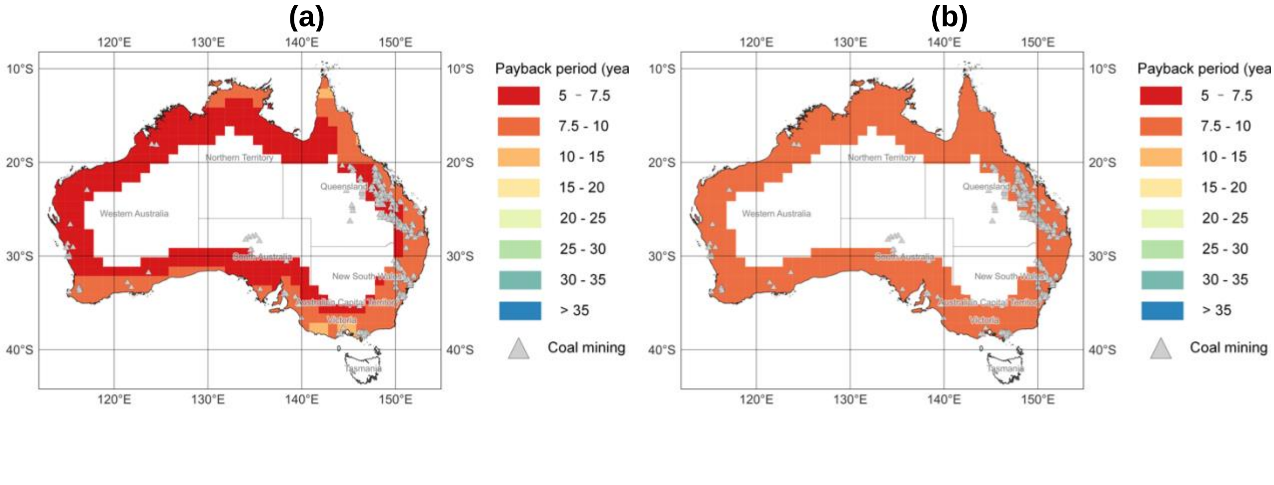


Figure 1: CSP-MED and PV-RO payback periods at different conditions

Applying the results above in Australia, Figure 2 (a), (b), and (c) present the payback period for the PV-RO cogeneration plant, PV-RO water-production only plant, and CSP-MED cogeneration plant, respectively. So far, PV-RO has shown to have a lower payback period than CSP-MED, but if solar-driven desalination is the way to move forward in Australia for sustainable electricity and water production to make other forms of energy (e.g., hydrogen), CSP-MED could be the solution—especially when requiring a 24 hour operation. As mentioned previously, Australia has been transitioning from mining coal to making green hydrogen. However, this could mean that inland towns with economies built around coal mining would be negatively affected. Thus, converting those towns from coal to green hydrogen production hubs is recommended, which would then require a substantial amount of electricity and water. In this scenario, CSP-MED is the solution for those towns as the electricity and water are made onsite, compared to PV-RO, where water must be transported from the coastline to the inland towns. This would increase the pumping costs of PV-RO and would increase its payback period. By observing Figure 2 (c), the CSP-MED could be the solution for some inland towns in Northeast Queensland, Western Australia, and South Australia, where the payback period is under 15 years. However, it must be noted that the hydrogen transport cost has not been accounted for in this study. Thus, adding this additional cost would increase the payback period for inland sites, and would still give the edge for coastline sites—especially the ones near international ports of where hydrogen will get exported.



(c)

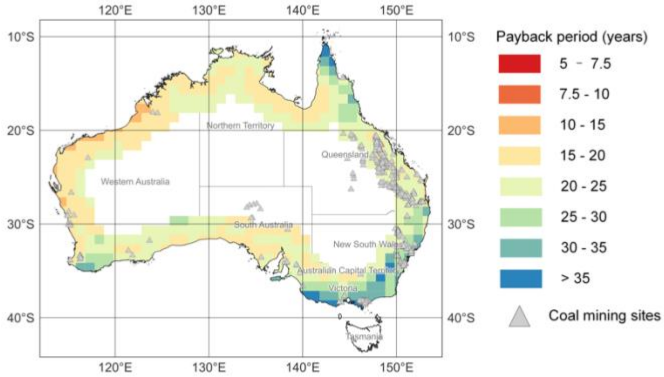


Figure 2: Payback period of (a) PV-RO cogeneration plant, (b) PV-RO water production only plant, and (c) CSP-MED cogeneration plant

Conclusion

Overall, the integration of solar energy with desalination will play a future role in generating clean energy and producing freshwater in Australia to achieve the net zero emissions target. However, this study has shown that a Barassi Line does not exist in Australia, since PV and RO systems are cheaper, and a more mature technology compared to CSP and MED. Nevertheless, since both CSP-MED and PV-RO are shown to have a reasonable payback period, both could be installed hand-in-hand and be part of the electrical generation and water production mix going forward (in the right locations).

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