maine'spowerproject

maine'spower

INNOVATION, COLLABORATION, LEADERSHIP AND ACTION

Main Recommendations and Findings: Executive Summary

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Project Outline

- The Maine's Power project is a collaboration of business, community, and government organisations, which has a goal to achieve a 30% reduction in the greenhouse gas emissions of Castlemaine's four largest energy users by 2010 (from 2006 levels).
- Castlemaine is a town of some 8000 people in north-western Victoria. The town is home to four energy-intensive industrial facilities which employ approximately one quarter of the town.
- The first stage of the project involved mapping the energy landscape, including investigating peak demand and supply constraints of the region and energy use patterns of the four facilities.
- The second stage of the program involved scoping a range of options for emissions reduction, including energy efficiency, demand management and alternative generation options to replace or supplement the four participants' grid-based electricity requirements.
- The third stage of the project involved providing the participants with information to guide planning their preferred pathways for reducing carbon exposure and investing in cleaner energy infrastructure.

The project is an example of true collaboration amongst multiple sectors working together to achieve solutions to climate change. It is expected that the learning, techniques and partnership model of this project will be directly transferable to other Australian communities.

Main Findings:

Stage 1: Energy usage and emissions - based on reference year from October 2006-Sept 2007

- Total energy used across the four sites was 323,270 gigajoules per year (GJ/yr), with associated greenhouse gas emissions totalling 61,505 tonnes.
- Most energy was supplied by natural gas (204,983 GJ/yr), followed by electricity (165,542 GJ/yr) and coking coal (estimate of 8,434 GJ/yr).

- Total emissions reduction required to meet the 30% target was 18,450 tonnes/year if production for the partners remained the same.
- Site 1 accounted for over two-thirds of energy consumed (227,312 GJ) across the case study sites, and required proportionate savings in greenhouse gas emissions of (13,484 tonnes/year).
- Site 2 was found to have operations that placed the network under stress from peak loads for a small number of hours per year

Stage 2: Energy technology options

- Economic analysis was performed for several technology options, including solar thermal, solar photovoltaic (PV), wind turbine and natural gas based combined heat and power (CHP) systems for the production of electricity and/or hot water.
- CHP and solar thermal offered the most attractive payback timeframes, while solar PV and wind were less competitive due to geographical characteristics of the study area, high capital costs and resource availability.
- CHP provided the most potential for affordably reducing greenhouse gas emissions, with potential savings of approximately 54,000 tonnes/year. Sites 1 and 3 were considered the best candidates for this technology.
- Sites 2 and 4 were better suited to energy efficiency initiatives combined with Green Power purchases or local wind and solar technologies albeit with longer payback periods.
- Depending on the price achieved for exported (excess) electricity, CHP systems could be paid back within 3-6 years for site 1 and 3-10 years for site 3. The range reflects differences in assumed export price for electricity and the change in gas price over time.
- Demand side measures to increase energy efficiency and reduce peak loads were also considered.

Stage 3: Preferred options

- Site 1 is considering the installation of CHP, along with energy efficiency initiatives. Site 1 has also expressed an interest in a number of smaller local renewable options such as solar PV for lighting. The business is considering these options against other passive measures such as extensive use of sky lights for instance in the design of their expanded facilities.
- Site 2 is considering the potential for energy efficiency measures as well as green power purchases. In addition the business can potentially reduce peak demand in the local network by developing an energy recovery system in partnership with the local distribution company.
- Site 3 is exploring the potential for CHP and solar thermal to reduce their energy demand for water heating. Energy efficiency may also be considered for this organisation.
- Site 4 is currently pursuing both green power purchases and energy efficiency measures.

Stage 2 and 3 investigations also revealed a number of considerations relating to the impact of local generation on the network and resource sharing of electricity and heat between the case study sites.

With production at Site 1 estimated to double in the coming years the installation of 4 MW of CHP would result in the emissions intensity in the baseline year of 1.1 kg of CO_2 per kg of product to fall to 0.69 kg of CO_2 per kg of product.
This represents a 63% reduction in emissions intensity for Site 1 alone and a reduction of greenhouse gas emissions by 32,340 tonnes CO_2 per annum over a projected business as usual case.

Lessons and recommendations

Partnerships are very useful

Having the contributions and input from all major stakeholders in energy usage and distribution in the project was essential to ensure that data was accurate, that options investigated were fully scoped for cost and regulatory barriers and to most importantly to motivate and support each partner in their ability to take action.
It also makes for better regional energy planning for the DNSP which is likely to make for better energy planning decisions at a lower overall cost to all participants and the community if demand management or embedded energy generation options are implemented.
Such a partnership is only really possible if clear guidelines agreed, objectives are formed and an environment of trust is developed in which potentially sensitive commercial information is able to be shared.
It also enables innovative solutions to be investigated and possibly implemented, particularly solutions in which demand management solutions are shared across two or more businesses and the DNSP.

Regulatory Cycles for energy distribution

The regulatory authority, originally the Essential Services Commission, now the Australian Energy Regulator (AER), decides how much Distribution Network Service Providers (DNSPs) can receive in revenue by setting a price cap. These caps are set in 5 year determination cycles. The current Victorian cycle runs from 2006-2010.The relatively long nature of these determination cycles means that unforeseen changes to the distribution network such as large scale embedded generation or demand reduction can impact on the regulated income for the DNSP. As such, initiatives such as this require the DNSP to participate directly to facilitate the project outcomes to be ideally delivered as part of the normal determination cycle. In addition the AER in April this year initiated a Demand Management Incentive Scheme (DMIS) for Victoria. The scheme will allow a DNSP to implement and recover costs for some innovative non-network solutions for reducing peak or base loads. The energy recovery system for Site 2 is an example of a project that could potentially fit the scheme. The scheme is due to start in the next determination cycle (2011-2015). Similar schemes will be rolled out by the AER in other states.

If the project is initiated during a midpoint in the determination cycle it may result in reduction in revenue for the DNSP, in which case the DNSP may charge the proponent to initiate the project, a cost which might have otherwise been captured as part of the network determination. With the next Victorian cycle starting in 2011 a delay in the implementation of demand management devices seems inevitable in the Maine's Power project.

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