Submission to the Cost Benefit Analysis of Smart Metering and Direct Load Control: Phase 1 Reports for the Ministerial Council on Energy's Smart Meter Working Group

1 November 2007

We welcome the opportunity to comment on the Phase 1 Cost Benefit Analysis of Smart Metering prepared for the Ministerial Council on Energy's (**MCE)** Smart Meter Working Group **(SMWG).**

This submission presents the views of the Consumer Utilities Advocacy Centre (CUAC), St Vincent de Paul Society Victoria (SVDP) and Alternative Technology Association (ATA).

CUAC is an independent consumer advocacy organisation, established to ensure the interests of Victorian electricity, gas and water consumers, particularly low-income, disadvantaged and rural consumers, are effectively represented in the policy and regulatory debate.

SVDP Victoria has approximately 8000 members and volunteers in Victoria (40,000 nationally). The society assists approximately half a million individuals annually across Victoria (over 1.5 millions nationally). Of this, a significant number are based in the non-metropolitan area. SVDP also delivers a number of community support services including: aged care facilities, housing services, youth services and disability services.

ATA is a not-for-profit organisation established in 1980 to promote the uptake of sustainable technologies in order to protect our environment. The organisation provides service to over 4000 members, who are actively promoting sustainability in their own homes by using good building design and implementing water conservation and renewable energy technologies.

This submission has been structured into two parts. In part one we address issues arising from the consultants' reports and in part two we outline issues that we believe should be included in the Phase 2 Analysis. Our response is in relation to the following three consultants' reports: NERA (2007) *Cost Benefit Analysis of Smart Metering and Direct Load Control Work Stream 4: Consumer Impacts, Phase 1 Report* (**Consumer Impact Report**), CRA International (2007) *Cost Benefit Analysis of Smart Metering and Direct Load Control Work Stream 5: Economic Impacts on Wholesale Electricity market and*

Greenhouse Gas Emissions Outcomes, Phase 1 Report (**Market Modelling Report**) and NERA (2007) *Cost Benefit Analysis of Smart Metering and Direct Load Control: Phase 1 Overview Report* (**Overview Report**).

Part 1: Issues arising from the reports

1.1 Demand Response

The residential demand elasticity analysis in the *Consumer Impact Report* indicates that while critical peak demand may be reduced, there may also be an increase in consumption at other times as a result of Critical Peak Pricing (CPP) and Time Of Use (TOU). We are concerned that the residential demand elasticity analysis has made no attempt to estimate the long term demand changes in residential weekend consumption.

The report states that:

> "[I]t was assumed that retailers would respond to any new peaks that arose by modifying tariffs in the long run. This analysis has assumed that retailers respond by requiring users to pay a weekend tariff that is equal to the current level of tariffs. We welcome feedback from interested parties with respect to these assumptions and alternative methods of addressing this issue for Phase 2."[1]

We believe that a zero change in long term weekend demand response is likely to over-state the consumer benefits. We are concerned that the exclusion of the weekend demand response analysis may result in an underestimate of the increase in non-critical peak day consumption and subsequent customer and market impacts. Unless a weekend tariff is higher than TOU weekday prices, we can safely assume demand will be shifted to weekend times. And if weekend prices are the same as TOU weekday prices, then any change in weekend consumption is likely to mirror the non-critical peak workday, and hence the weekend change should be rolled into the net non-critical peak day change.

1.2 Peak load reductions

The *Market Modelling Report* suggests the benefits of peak load reduction decrease with incremental increases in demand reductions. It is argued that the first MW of reduction is more likely to reduce either a load shed event or new generator costs than, for example, a MW reduction after 20% of the peak has already been shaved. We believe this is not entirely accurate.

The ability of demand reductions to affect supply infrastructure investment is driven by the size of the demand reduction relative to the supply planning regime, available capacity headroom, load profile at any given time and the underlying consumption growth rate. For instance, a 1MW reduction, at anytime, is unlikely to reduce the need for new generation as very few generators are planned on a 1MW basis. It may however reduce investment in network assets. Furthermore, cumulatively, 1MW reductions may

[1] NERA (2007) *Cost Benefit Analysis of Smart Metering and Direct Load Control Work Stream 4: Consumer Impacts, Phase 1 Report*, p. 20.

defer capital spending on new generators of 30MW or more if the demand reduction rates are sufficient to delay the breach of desired capacity headroom. This could occur regardless of how much peak is already shaved, as the reduction could be relative to a projected future increase. It is unclear exactly how the assumed decrease in benefit from incremental increases in demand reductions in this analysis flow through to their modeled outputs. We believe this may warrant revisiting.

The *Market Modelling Report* also suggests that if TOU pricing shifts demand from peak to off peak times, and there is not investment in new low emission baseload technology, emissions are likely to increase.[2] However in the summary and key findings parts of the report, it is suggested that all functionalities provide financial and greenhouse gas benefits to the market.[3] Does the summary finding assume that the functionalities are not coupled with TOU pricing and/or coupled with new clean baseload generation investment? We cannot see how the summary finding could be made, given the prior analysis, without such assumptions and would welcome clarification on this point.

1.3 Load block analysis

The load block analysis in the *Market Modelling Report* shows a significant shift of demand from peak to off-peak times. As load shifting is a key tenet of dynamic pricing we recommend that the Phase 2 analysis investigates the following:

- If a carbon price[4] ($15-$25t) is applied, what would the cost of this shift in demand be? Assuming that today's emission factors for baseload and peak supply are used; and
- How would such a load shift affect current baseload capacity? Specifically, will it require new baseload capacity to maintain headroom margin or bringing on baseload not currently in operation? Given water constraints, what is the reliability of any additional baseload required?

We believe these are important issues and thus should be incorporated into the cost benefit analysis.

1.4 Import/export functionality

Whilst it is accepted that the inconvenience and cost of altering metering – not to mention the confusion arising from the inconsistencies in requirements across retailers, distribution businesses and jurisdictions – acts as a disincentive for individuals wishing to install small-scale domestic renewable energy systems, the adoption of simple import / export functionality may not actually result in the best outcome for micro-generation proponents, as concluded by the *Overview Report*.
At present, individuals wishing to install renewable energy are required to either keep their current meter as is, replace their electricity meter with an import/export capable one,

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[2] CRA International (2007) *Cost Benefit Analysis of Smart Metering and Direct Load Control Work Stream 5: Economic Impacts on Wholesale Electricity market and Greenhouse Gas Emissions Outcomes, Phase 1 Report,* p. 38
[3] Ibid. p 43
[4] We believe this range represents a likely short to medium outlook (up to 2020) for carbon prices. While the *Market Modelling Report* suggests the price by 2020 may still be around the $20 mark, we believe it would be prudent to test beyond this given the potential for carbon reductions imperatives to be better understood and accepted by 2015 and beyond.

or install an additional second meter, typically entirely at the proponent's cost. Consistency within and across jurisdictions, as well as the costs of metering being absorbed by the market as is the case for all other classes of market customers, would be a welcome improvement on the status quo.

However, current developments locally and internationally in the provision of incentives for renewable micro-generation require a variety of metering arrangements. Best-practice incentives for micro-generation generally favour gross metering arrangements capable of measuring import and export simultaneously, as discussed below. Locking Australia into the roll-out of smart meters with simple import/export functionality at such a time of change may actually act as an impediment to the adoption of micro-generation.

The adoption of mandated feed-in laws in over 40 countries internationally has seen the wide-spread adoption of renewable energy across the world. Recently, South Australia has adopted feed-in tariffs locally, and both the ACT and Victoria are in the process of developing similar regimes. In each case, the intention of the laws is to stimulate the up-take of small-scale renewable energy technology.

In the case of South Australia, feed-in tariffs are paid on the net imported to the grid, after in-home consumption, via net metering through meters with import/export capabilities – the same functionality as recommended for inclusion in a minimum national functionality in the *Overview Report.* However, feed-in tariff internationally are typically applied to the gross production, recognising the full benefit to the network from this additional generation, rather than merely the proportion of generation which is imported to the grid.

In addition, a net export metering regime for feed-in tariffs discriminates against both owners of smaller grid-connected systems and those who are more likely to consume electricity during the day, such as senior citizens or stay-at-home parents. In cases such as these, where instantaneous system production rarely exceeds household consumption, system owners rarely exporting electricity to the grid would not be able to receive the benefit for premium feed-in rates offered, and thus would gain very little financial return on their investment.

Further, a system of net export metering creates significant uncertainty in the market, both in terms of potential financial return from the feed-in tariffs for the system owner, and in the cost of the system for the government and wider community. The introduction of gross metering allows for far clearer estimates of ongoing costs and benefits of the tariffs due to the relative predictability of gross electricity production for a given sized installation over a given time frame.

The application of net metering in South Australia was adopted due to a desire to maintain the status quo for simplicity, as outlined as follows:

> "Current metering arrangements provide a 'net export' outcome. Using 'gross production' would require an alteration to existing installations and a change to the methods applied to future installations."[5]

The roll-out of interval meters with import/export functionality has the potential to lead to a similar justification by future governments when considering incentives for renewable energy, and as such result in sub-standard feed-in tariff arrangements, and thus further disadvantage renewable micro-generation proponents.

The ACT government is currently proposing a feed-in tariff scheme based on gross production, the Victorian Government is considering a mandated feed-in tariff and Queensland has announced their intention to introduce something similar. As such it is a vital time for securing appropriate incentives for micro-generation systems, and functionality slated for the roll-out of smart meters now could wind up being either obsolete or obfuscatory in the future. A feed-in tariff scheme based on gross production metering, whereby the entire production of the system is measured by either a separate meter or a second element within the one meter, as is proposed in the ACT and adopted almost universally internationally, would not be compatible with the import/export functionality as proposed.

We recommend that the Phase 2 analysis investigates options for the application of feed-in tariffs on the gross production from renewable systems. Clearly two element meters would be able to deliver such outcomes but other less cost demanding options should be included in the analysis.

1.5 Functions affecting demand response

We do not believe that the daily reading functionality should be classified as a functionality that provides the capability of enhanced energy usage information to consumers. While we can appreciate that daily readings are a useful tool to retailers in terms of information collection, hedging activities and instant settlement of accounts, classifying the functionality as a demand response enhancer is misleading. The concept of daily readings does not incorporate a channel for consumer information. Daily readings could be included in the national minimum functionality specification without one single customer obtaining information about their consumption level/pattern. The *Customer Impact Report* rightly acknowledges this:

> "Daily remote reading allows retailers to access customer usage information on a daily basis. This does not automatically imply that customers will be provided with that usage information on a daily basis."[6]

What is certain is that customers will in one way or another pay for the meters and their additional functionalities. We raise this issue as it is important to understand who benefits from the various functionalities, both directly and indirectly, as a minimum functionality specification is likely to involve some compromises. Many functionalities

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[5] Government of South Australia (2007) South Australia's Feed-In Mechanism for Residential Small-Scale Solar Photovoltaic Installations - A Discussion Paper, February 2007, p. 11

[6] NERA (2007) *Cost Benefit Analysis of Smart Metering and Direct Load Control Work Stream 4: Consumer Impacts, Phase 1 Report*, p. 42

can be added at a very low incremental cost but ultimately trade-offs will occur due to bandwidth constraints or the total cost of several low incremental cost functionalities. It is thus important to highlight which stakeholder groups directly benefit from each of the proposed functionalities. We recommend that the cost benefit analysis framework does not classify daily reads as a function that enhances energy usage information to consumers.

1.6 The value of PV generation

Whilst the *Overview Report* accurately highlights many of the benefits of small-scale distributed generation such as rooftop solar photovoltaics (PV), there is an error made in calculating the worth of PV generation. The report states that:

> "Simple interval data recording would allow tariffs to be designed based on a customer's contribution to maximum demand, such that sustained changes in maximum demand through the installation of PV generation could be achieved. Imported/export functions would allow this to be further extended to those customers who import electricity to the grid during network load peaks, through a feed-in time of use tariff. However given that most PV generation customers are unlikely to be ***'exporting'*** (our emphasis) during peak network load times, the benefit is expected to be small."[7]

There are two issues here. Did the paper intend to use ***'exporting'*** (from the grid) and if so, why would this make the benefit small? Assuming the wording is the correct reflection of the papers' intent, if a PV customer is unlikely to be exporting electricity from the network at peak load times, this has no impact on the feed-in time of use tariff.

If the paper intended to say a PV customer is unlikely to be ***'importing'*** to the grid during peak network times, then this would be erroneous also. Network peaks and residential peaks typically do not correlate. PV generation correlates with network peaks (around midday) but drops off for residential peaks (around 6-7pm). Therefore PV generators are very likely to benefit from exporting at the network peak time given time of use feed-in tariffs.

We would welcome clarification on this point including how it impacts on the broader analysis undertaken by NERA.

Part 2: Additional issues for Phase 2 Analysis

2.1 CPP Analysis

We recommend that an analysis of the impact of price 'fatigue" in regards to CPP be undertaken. Price fatigue occurs when there a number of hot days in a row and where the ability and willingness of households to adjust consumption diminishes over time. In such instances one would expect the own price demand elasticity to change on consecutive CPP days.

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[7] NERA (2007) Cost Benefit Analysis of Smart Metering and Direct Load Control: Phase 1 Overview Report, September 2007, p. 79

In addition to an analysis of consecutive CPP days and demand response, we recommend that the Consumer Impact analysis investigates the financial impact of consecutive CPP days on particular households – such as those that are aged or with young families, and as such less able to respond to CPP signals.

Furthermore, no modelling has been done in regards to the impact of who is calling the CPP events. As the distribution businesses and the retail businesses have different reasons for calling CPP days, the analysis should include a comparison of the impact CPP events may have on the network and the market more broadly. We believe both an examination of the motives for calling CPP events and a comparative impact analysis is warranted.

2.2 Distributional impact of CPP and TOU pricing

We welcome the intention to examine the distributional impact smart meter enabled pricing arrangements will have on consumers, with particular focus on low-income and vulnerable customers, in the Phase 2 analysis.

Consumer demographic

As households' ability to shift demand is the key determinant for whether consumers will be financially better or worse off in a TOU pricing environment we strongly recommend that the analysis collects and links the following information in order to develop useful customer profiles:

- Consumption levels (i.e. low, medium, high);
- Consumption pattern (time of use);
- Household composition (i.e. couple, single, family); and
- Household income levels

While the income level component is important in order to understand price impact on consumers as well as households' ability to make changes in the medium to long term (i.e. by replacing appliances), it is actually factors such as household composition and employment status that will have the greatest bill impact. We therefore recommend that the customer profiles include information about household composition and employment status (i.e. full time employed, part time employed, retired, unemployed). Furthermore, if such an analysis indicates that households with young children and/or the elderly are likely to be financially disadvantaged due to an inability to shift load, we believe additional analysis into the likelihood and impact of under-consumption on particular groups in the community (children, the elderly, people with ill-health) is warranted.

We recommend the Victorian Dept. of Human Services' Victorian Utility Consumption Survey as a key source of information on energy consumption and costs, including low-income households.[8] Also, where no income data exists we would support using health care cards as a proxy for income.

[8] DHS (June 2002), Victorian Utility Consumption Survey 2001. See http://www.office-for-children.vic.gov.au/__data/assets/pdf_file/0010/84385/utility_consumption_survey_2001.pdf
DHS has recently completed a new utility consumption survey which is expected to be released in January 2008.

Dual fuel households

We recommend that the Phase 2 analysis includes a separate study into the price impact on dual fuel (gas and electricity) households on TOU tariffs. We believe dual fuel households are likely to have different demand elasticity compared to all-electric households due to differences in electricity demand (theirs is lower) and usage patterns. As such, the financial impact on these households is likely to differ from all-electric households.

2.3 Impact on households with dedicated off-peak circuits

We strongly recommend that an analysis is undertaken into the price implications of switching households with current dedicated off peak circuits (with and without boost options) to a TOU pricing arrangement. This is a particular concern for households currently taking power through a two-element meter (or even three-element in some places), which may not be available as a result of a smart meter roll-out.

We have previously raised this issue in relation to the Victorian minimum functionality specification process as our estimates indicate that price increases will potentially affect as many as 500,000 Victorian households, mostly confined to regional centres and rural towns.[9]

Customers currently on two rate electricity have specific appliances that are hard-wired to receive off-peak consumption at a specific rate and all other consumption at a general domestic or general residential rate. With the installation of a single-element interval meter these customers will be allocated to a new – TOU – network tariff. We have estimated that the reallocation will result in a peak rate rise by approximately 25% and extend the off peak rate to all households' consumption between 11 pm and 7 am weekday and all weekends.[10]

A discussion paper on metering for electric off-peak heating issues by the Victorian Department of Primary Industries rightly noted that:

> "A single element meter cannot distinguish between *types* of use within the defined period. As a consequence, the same network tariff would be applied to all uses in any given period, whether the consumption is for electric off-peak water heating or other uses."[11]

Subsequently, customers with electric hot water and slab heating will be disadvantaged by a smart meter roll-out if unable to separately hard-wire these appliances. It should also be recognised that hot water services and slab heating are major appliance investments and that customers are unlikely to change appliances in the short to medium term. Indeed, as the majority of these consumers live in non-metropolitan areas without

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[9] This section is based on a paper produced by CUAC, St Vincent de Paul Society and Victorian Council of Social Service which was tabled at the Victorian Advanced Metering Infrastructure Industry Steering Committee in September 2007.

[10] Estimate based on a comparison of Victorian retail two rate peak charges with TOU peak charges.

[11] Dept of Primary Industries (December 2006), Discussion Paper, *Metering for electric off-peak heating*, p. 5

access to reticulated gas they will have limited options in terms of converting appliances and/or fuel substitution.

Many of the 6 and 8 hours off-peak electric hot water and space heating units have boost functions incorporated into the appliance design. However, these appliances boost during peak periods (electric slab heating typically boost for three hours between 2-5pm) but as they are hard-wired into the meter the boosting load is assigned to off-peak tariffs although the usage occurs during peak times.

Without a second element this boost function will attract a time of use peak charge rather than an off-peak charge. This is approximately a 300% increase to the cost experienced by the customers for these periods. The magnitude of the impact on households would depend on a few factors but consumers with electric slab heating as well as large electric hot water tanks with household members home during the day (which means that the water service will boost more regularly) are clearly going to be among the most disadvantaged.

Based on the figures the Victorian distribution businesses provided in their 2007 Tariff Reports we have calculated that 497 000 customers are on tariffs with a dedicated circuit.[12] The vast majority of these appear to be residential customers.[13] Hence as many as over 1.2 million Victorians live in households that currently have access to separate off-peak loads for electric hot water and/or electric heating.[14] In terms of actual price increases to these customers we have been informed that the *average* is likely to be just over $50 per annum (in distribution charges) but that some households, characterised by the factors discussed above, may incur an increase of several hundred dollars per annum.

We acknowledge that the distribution businesses *may* have a business case to roll-out two-element meters to these customers, but the magnitude of the possible disadvantage clearly warrants a thorough investigation into the impact of single element meters (both in terms of numbers of customers affected and price increases) as well as an assessment of possible mechanisms that can mitigate these impacts.

2.4 CPP and TOU impact on emission levels

Given the contradictory analysis and summary findings presented in the *Market Modelling Report*, we conducted a simple analysis to test the impact demand changes would have on emission outcomes in Victoria. Our analysis is based on elasticity of demand estimated by NERA in the *Consumer Impact Report*, which analysed long run responses to critical peak pricing. We then undertook sensitivity analyses to test the effect of changing certain assumed variables. The 'baseline' assumptions we used in testing the impact of CCP in Victoria are as follows, with variables tested highlighted in yellow:

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[12] This calculation is based on the following figures from the Network Tariff Reports: 26 873 AGLE customers, 26 884 Citipower customers, 186 624 Powercor customers (plus 18 318 customers on the Climate Saver tariff), 160 000 SPAusnet customers and 78 218 United Energy customers.

[13] Some of the tariff reports do not separate between residential and business customers on dedicated circuit tariffs.

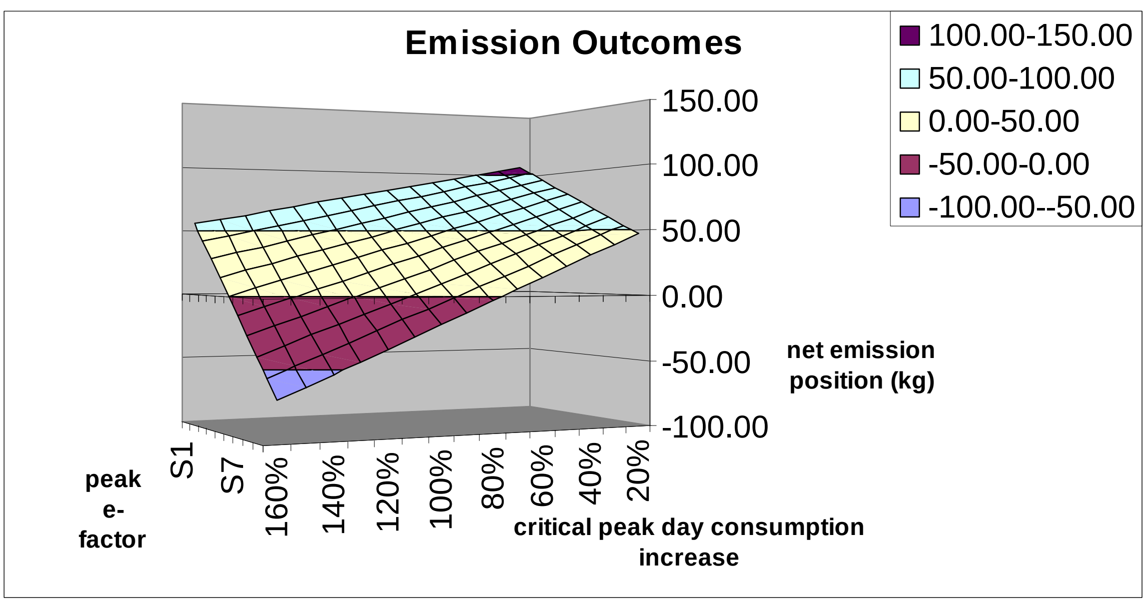
[14] This is a conservative estimate based on the average household size being 2.58, as reported in the DSE Victoria in the future report.

critical peak day demand change	-30%
% change at peak time	80%
non critical peak day demand change	1.8%
% change at peak time	-5.00%
avg. non critical peak daily consumption (kWh)	17.81
critical peak day consumption increase	20%
avg. critical peak day consumption (kWh)	21.37
tCO2e – off peak generation	1.3
tCO2e – peak generation	0.7

Table 1: baseline assumptions tested

As only percentages of daily average and peak time consumption change were presented, it is unclear what the net change in energy consumption would be. Given the 7am-7pm peak time assumption, we assumed the greater portion of the reduction on CPP days would occur during this peak hence the 80% baseline assumption. We have taken a crude average of summer and winter demand response on non-CPP days - hence the non-CPP day demand change is 1.8%. Given the effect of TOU and CPP should be to reduce peak consumption, we have assumed that while demand increases on non-CPP days, there will be a decrease at peak times on those days, hence the -5% change at peak times baseline assumption for non-CPP days. Lastly, it was unclear how net consumption differs on CPP days and non-CPP days. Our baseline assumption is that the net increase on CPP days is 20% relative to the average day. Reasons for assuming peak times are from 7am-7pm and for excluding weekend consumption changes were not clear to us and we would welcome an explanation for this.

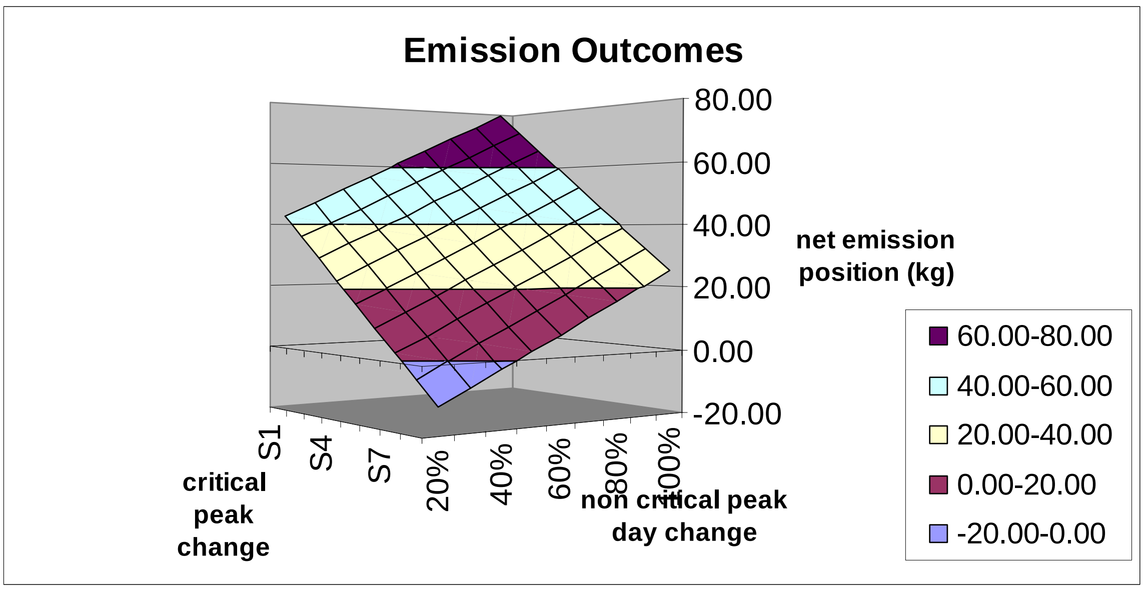
Our analysis confirmed that as the effectiveness of TOU and CPP pricing increases the emission outcomes worsen, as demand is shifted from peak to shoulder and off-peak times (where emission factors are typically worse).



Sensitivity analysis Graph 1

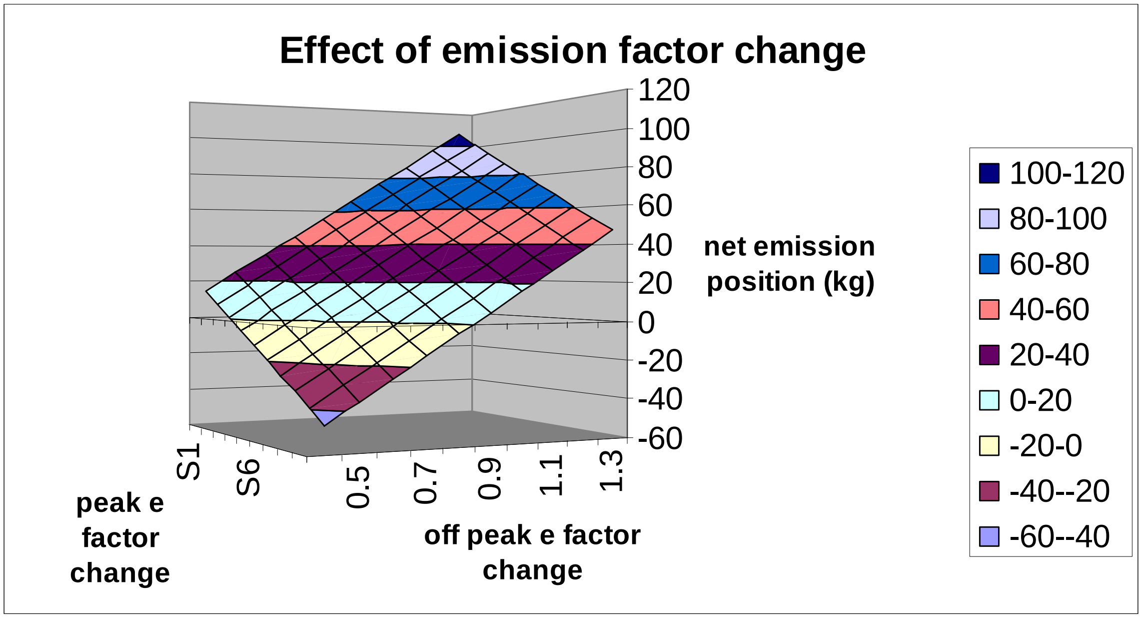
As the assumed emission factor assigned for peak generation increases (S1-S10 representing 0.4-1.3tCO2e/MWh), the net emission position improves. This is because over the course of a year, there is a reduction in peak demand, meaning the higher the peak demand emission factor, the greater the relative emission decrease. As consumption on a critical peak day increases relative to non-peak days, the net emission position also improves. This is because any assumed increase in critical peak day consumption relative non-critical peak days magnifies the effect of any reduction in demand on critical peak days. Notably, as the desired effect of CPP and TOU tariffs take place, emission outcomes worsen.

The second scenario tested was for variations in the percentage of total consumption change attributable to changes in peak time consumption during non-critical peak days and critical peak days. In all but five of 81 scenarios tested, emissions were positive. S1-S9 represents critical peak day consumption change, attributable to changes in consumption at peak times ranging from 20% to 100%. Because non-critical peak day consumption increases with CPP and TOU tariffs, the greater the percentage change at peak times, the better the emission outcome. The key result being that as the desired effect of CPP increased, emission scenarios worsened.



Sensitivity analysis Graph 2

We accept that the scenarios and sensitivities tested are rudimentary and not completely accurate reflections of electricity market dynamics, e.g. reductions in peak consumption do not necessarily get moved to off-peak time but also to the shoulders. For this reason, we tested changes in emission factor assumptions, presented in Graph 3 below. S1-S10 represents changes in the emission factor for peak generation ranging from 0.4 – 1.3tCO2e/MWh.



Sensitivity analysis Graph 3

This analysis shows that only in the event of very unlikely assumptions would an emission reduction be achieved. With other baseline assumptions remaining constant, the emission position only becomes negative once baseload is assumed to be 0.8tMWh or less and at this point, the peak load needs to be 1.3tMWh for emissions to be negative.

In summary, based on the data, assumptions and analysis presented in the consultants' reports and this submission, it is more than likely that smart meter enabled TOU and CPP will result in increased greenhouse gas emissions unless massive reductions in the emission intensity of baseload can be made. While our analysis covered Victorian data only, the firmness of the outcome under various scenarios suggests that the findings would be replicated across other jurisdictions.

Our analysis highlights the need for transparency of data and assumptions used in the cost benefit analysis. Specifically, in this instance, we do need to know the following in order to avoid uncertainty about the analysis:

- the net consumption change assumption across CPP and non-CPP days;
- the emission factors applied to peak and off-peak times; and
- the net consumption assumed to occur at peak (7am-7pm) times.

Please do not hesitate to contact May Johnston (03 9639 7600), Gavin Dufty (03 9895 5816) or Brad Shone (03 9631 5406) should you have any questions about the above.

Yours sincerely,

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