Deferral of network investments by DSM - New Zealand experiences

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Overview

• NZ power system – some background
• Case 1 – Energy efficiency
• Case 2 – Load management, ripple control
• Case 3 – Orion, managing peak in distribution
• Case 4 – Transpower, South Island DSP Trial
Demand/generation growth

[Graph showing demand and generation growth from 1974 to 2006, with categories for Hydro, Geothermal, Oil, Coal, Gas, and Others.]
Transmission – the issues

Aging assets – new investments needed, but nobody wants it nearby

DSM can help to mitigate risk of delays in transmission built or as an option to defer the need.
Transmission price signals

• 3 transmission signals may trigger DSM:
  – Anytime transmission price signal – “LRMC proxy”
  – Nodal price signal, when starting to congest
  – Grid support contract, when needed for reliability
Price signals – do the work?

• Transmission pricing methodology (TPM) works:
  – Specified as main driver for ripple control in NZ
  – Is the signal optimal?
    • Regional
    • Sunk costs

• Market price signals tend to come to late
  – Price separation appears when the problem is acute
  – Lack of long-term forward market (CfD between areas)

• Grid Support Contracts may work (yet to be seen)
  – See comments later…
Case 1 – Energy efficiency

Impacts from reducing NZ electricity demand through energy efficiency
Future demand scenarios

Average demand growth 2007 - 2042:
- low forecast ~ 0.9%
- medium forecast ~ 1.3%
- high forecast ~ 1.7%
Avoided costs: generation, T&D, energy

($2007 million NPV 4% real discount rate)

<table>
<thead>
<tr>
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<th>High to medium demand forecast</th>
<th>Medium to low demand forecast</th>
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<tbody>
<tr>
<td>T&amp;D</td>
<td>583</td>
<td>387</td>
</tr>
<tr>
<td>Generation</td>
<td>5817</td>
<td>5139</td>
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<tr>
<td>Energy</td>
<td>2593</td>
<td>3285</td>
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<tr>
<td>Total</td>
<td>8993</td>
<td>8811</td>
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Based on total system costs 2007-2042
Economic potential to achieve reduction till 2025 exists
Case 2 – Load management

Load management by ripple control – now and in the future
Ripple control

• Ripple controlled water heaters has been used for decades.

• Estimated ~880 MW controlled load (~13% of peak)
  – Up to 400 MW peaking capacity deferred ???
  – About 4 years of load growth
  – OCGT costs ~$1 million/MW or $70,000/MW per year
  – Generation savings equal to $28 million per year
  – Additional savings in T&D and energy costs

• Transmission pricing methodology specified as main driver behind use of ripple control by most distribution companies in New Zealand

• Risks: Lack of incentives to maintain + competition from other energy sources for future energy demand
Sample diurnal load profiles

Upper SI Daily Load Profile Snapshot - June 2005
New “old” technology taking over?

- Radio ripple control to be rolled out in New Zealand
  - Based on long-wave radio technology
- Has been used in Europe for years
- Highly reliable
  - Redundancy of all major parts
  - Quick (1 second to send signal)
- Lower costs alternative than building ripple injection plants
  - 3 masts can cover whole NZ with each of the major cities being covered from two masts
- Controlled areas can be targeted in great detail
  - Send signal to individual receivers, groups of receivers, or all
Case 3 – Load management/DG

ORION – Lowering peak demand growth in the distribution network
Breaking peak vs. energy trend

- Orion is the distribution company covering Christchurch, NZ’s third largest city
- It has been working on DSM since early 1990s
How did they do it?

Pricing:
- Households - Day / Night tariff
  - Day 21.30c/kWh
  - Night (9PM-7AM) 8.44c/kWh
- Households - Controlled tariff
  - 24 hour uncontrolled (one meter) 19.47 c/kWh
  - Economy 24 (one meter) 16.54 c/kWh
- Commercial/industrial
  - Large capacity component (consumers try to minimise own peaks)

Load control:
- Aggressive use of ripple control (households on controlled tariffs)
- Also controlled industrial loads (300 customers using ¼ of the load)

Generation:
- DG - Mainly local back-up generation
- Fuel Switching
  - Cogeneration, used for heating larger buildings
  - Gas instead of electric heating
Case 4 – Load management

Demand Side Participation and transmission network deferral – Transpower’s Upper South Island trial
Project purpose

• Transpower has to take non-transmission options into account whenever proposing upgrades to the grid.

• For that purpose Transpower is designing a Grid Support Contract product to:
  – identify (EOI/RFI);
  – evaluate (RFP); and
  – contract

  with provides of non-transmission options (generation or demand side)

• The South Island Demand Side Participation Trial project was designed to gain some real experience of DSP (generation side fully known) and to try a “final draft” of the Grid Support Contract product in practice.
Setup

- Fear that the project could be needed soon in the Upper South Island.
- Designed and approved in a hurry, early 2007
- Two stages:
  - 2007 Winter Pilot
  - 2008 Winter Trial
- Little time available for preparing 2007 stage
2007 Winter Pilot - Results

• Contracted with 14.2 MW from 16 different sources
• Sources called 7-8 times during the winter 2007
• Reliability by Source:

<table>
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<tr>
<th></th>
<th>Generation</th>
<th>Industrial</th>
<th>Coolstore</th>
<th>Hydro</th>
<th>Total</th>
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<td>MW contracted</td>
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<td>7.0</td>
<td>3.3</td>
<td>0.4</td>
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<td>5</td>
<td>4</td>
<td>2</td>
<td>16</td>
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<tr>
<td>Response</td>
<td>88%</td>
<td>72%</td>
<td>47%</td>
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<td>68%</td>
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<tr>
<td>Number of calls</td>
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<td>32</td>
<td>16</td>
<td>120</td>
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<tr>
<td>Zero responses</td>
<td>1</td>
<td>3</td>
<td>6</td>
<td>4</td>
<td>14</td>
</tr>
</tbody>
</table>

• Low reliability due to strict “success” criteria and little time for preparation
2008 Winter Trial - Overview

- RFP responses came in March 2008
- Finalise commercial terms in April / May. Likely to contract with 30+ MW
- Will use the Grid Support Contract structure
- Trial period will be June through August
- Calls will be system capacity threshold driven
GSC’s – some conclusions

• Can be used for:
  – Planned “economic” deferrals
  – Unplanned deferrals:
    • Demand forecasts wrong
    • Delays in transmission built

• Using it for planned deferrals risky
  – It can only use it once

• Upper South Island no longer at risk
  – Latest demand forecast changed perception of the need

• Need on the North Island this winter?
  – HVDC pole 1 partly out
  – 300 MW New Plymouth power station out
  – Dry - largest North Island reservoir (Taupo) at minimum
Questions?