Draft 2008 SOO generation scenarios

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Introduction

- Commission is required to publish a Statement Of Opportunities (SOO)
- Commission is in process of preparing a 2008 SOO
  - Demand forecasts
  - Generation scenarios *[and the drivers behind them, which could be used to develop new scenarios]*
  - PSA
- Aim is to finalise generation scenarios by end of March so that PSA can begin
- Draft generation scenarios have just gone out for consultation
  - http://www.electricitycommission.govt.nz/consultation/GPA
  - Submissions due 13 March
  - Also happy to take verbal feedback today

Scenario development process

- Assembling input data
  - Media releases
  - Consultant reports
  - Transmission to Enable Renewables project (TTER)
- Developing the scenario 'stories'
  - EC Board decision
  - Credible
  - Cover a range of outcomes
  - Consistent with current policy settings
- Running the Generation Expansion Model (GEM)
  - MIP model that seeks to minimise NPV of generation-sector post-tax costs
  - Two nodes, four seasons, 30-year horizon
- And iterate…

Five scenario ‘stories’

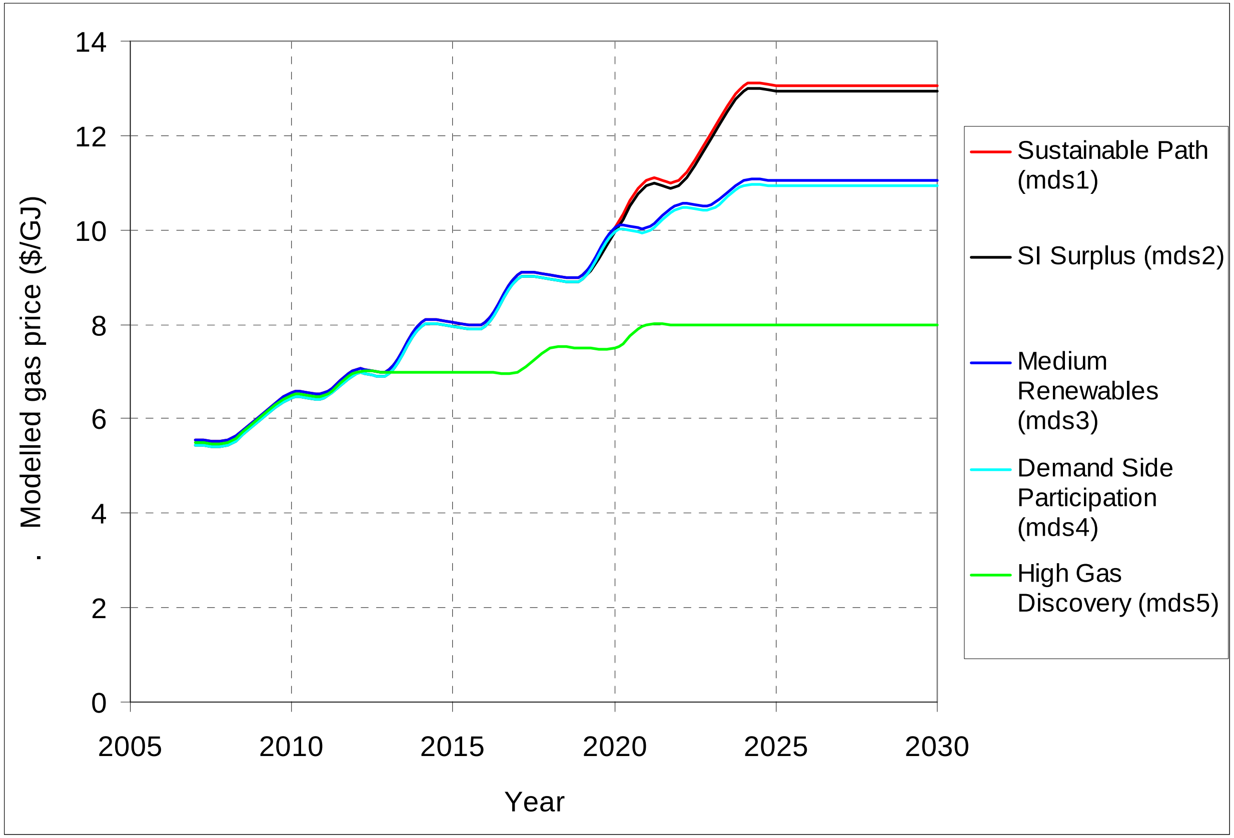
#	Scenario	Eventual carbon price ($/t CO_2e)	Moratorium on baseload thermal	Gas price	Renewables available	Fate of coal-fired Huntly units	Fate of HVDC Pole 1	Demand side
1	Sustainable Path	$50 (rising to this level by 2018)	Continues indefinitely	Baseline, rising sharply after 2010	Extensive hydro, wind and geothermal available. Biomass, marine and CCS available later	Closed by 2020 (Tiwai smelter and Stratford Power Station and also close in 2020s)	Half pole on standby until replacement in 2012	Baseline participation. High electric vehicles uptake
2	South Island Surplus	$40	Extends to 2028, then efficient gas-fired plant permitted	Baseline	Extensive hydro and wind available, especially lower SI. Geothermal less aggressively developed. CCS appears later	By 2020, two units out and two in dry-year reserve mode. (Tiwai remains in operation)	Half pole fully available until replacement in 2012	Baseline participation. No significant electric vehicles uptake
3	Medium Renewables	$35	Lapses 2019	Baseline	Extensive wind and geothermal, and some hydro available	As above	Half pole on standby until replacement in 2012	Baseline participation. No significant electric vehicles uptake
4	Demand Side Participation	$30	Lapses 2019	Baseline. Imported LNG available after 2020	Extensive wind and geothermal available. Little new hydro can be consented; some existing hydro must reduce output from 2020	Coal-fired units remain in operation until 2030	Half pole on standby until replacement in 2012	Extensive participation. High electric vehicles uptake, with vehicle-to-grid
5	High Gas Discovery	$20	Lapses 2019; CCGTs can be built to replace coal in the 2010s	Low	Moderate amounts of wind, geothermal and hydro available	Two units replaced by a new CCGT in 2015; the remaining two units displaced by CCGTs in the 2020s	Removed from service until replacement in 2012	Minimal participation. No significant electric vehicles uptake

How are these different from the 2007 draft GPA scenarios?

- For October 2007 draft GPAs, see http://www.electricitycommission.govt.nz/opdev/modelling/gpas/Oct2007
- A lot of similarities (same modelling approach, similar range of carbon costs and fuel prices, similar list of new plants, etc)
- But now:
  - Thermal moratorium
  - Status of HVDC Pole 1 pre 2012 is uncertain
  - More weight on early Huntly decommissioning (partial or complete)
  - No early Tiwai closure (though the smelter is closed in the 2020s in one scenario)
  - No 'coal scenario' (though new coal plant do appear towards the end of the High Gas Discovery, and coal with CCS in some of the more renewable scenarios)
  - More uncertainty about how much hydro and geothermal will be able to pass resource hurdles
  - EVs built into two scenarios
  - TTER plant information to come

Key inputs – fuel prices

- Assumed gas prices (as paid by electricity generators, at Huntly) shown below - these are *exclusive* of carbon costs



- Delivered prices of $4/GJ for coal and $25/GJ for diesel assumed (again exclusive of carbon costs)

Key inputs – transmission

- Special focus given to HVDC link
  - Assumption for this purpose (without prejudice to EC consideration of HVDC GIT application) is that HVDC will be a 1200 MW bipole from 2012, rising to 1400 MW with a fourth cable in 2018
  - Configuration between now and 2012 is still uncertain
    - Link could remain a monopole (assumed in 'SI Surplus')
    - Half pole 1 could return to full service (assumed in 'High Gas Discovery')
    - Half pole 1 could be used northwards intermittently (assumed in other three scenarios')
- Otherwise, it is assumed (for the purpose of producing generation scenarios) that AC transmission grid will be upgraded as required to connect generation and demand
- EC is currently developing methodology for co-optimising generation and transmission – may be able to be used in development of final SOO scenarios

Key inputs – technology costs

- A key scenario driver is the set of cost assumptions made for the various generation scenarios
  - Capital and O&M costs are entered on a per-project basis
  - Some variation in hydro and wind project costs is modelled, to indicate uncertainty about the relative merits of different sites (and encourage geographical diversity between scenarios)
  - GEM allows the cost of a generation technology to be changed from scenario to scenario: at present this feature is used to model unexpected wind costs (integration perhaps, or turbine prices?) in ‘High Gas Discovery’
- Next two slides provide a high level summary of the cost assumptions
  - Expressed in terms of LRMC, which we define as the mean price (at GIP) that is sufficient to cover all plant costs
  - Caution urged in comparing these LRMCs with those published in other documents – differences in assumptions (discount rate, timing of capex, tax treatment, project life, etc, etc) can easily make a difference of $20/MWh or more to the end results

Renewable LRMCs

Category	Island	Assumed load factor	Best resources – LRMC ($/MWh)	Capacity at this price (MW)	Next resources – LRMC ($/MWh)	Capacity at this price (MW)	Lower-grade resources – LRMC ($/MWh)
Wind (*)	NI	(intermittent)	80-85	~500	Ballpark of 95	Over 2000	Over 100
	SI	(intermittent)	Same + ~$5 for HVDC	~300	Same + ~$5 for HVDC	Over 1000	Over 100
Geothermal (**) (+)	NI	90%	80	250-300	Ballpark of 85	~400	As much as 100
Hydro backed by storage (+)	NI	50%	75-80	~200	90-110	~600	N/A
Run-of-river hydro	NI	(intermittent)	80-95	~100	95-120	~200	Very high
	SI	(intermittent)	Same + ~$5 for HVDC	~100	Same + ~$5 for HVDC	~200	Very high
Biomass cogeneration	Mostly NI	70%	130	150			
Marine	Both	(intermittent)	125	400			

Thermal LRMCs

Category	Assumed load factor	LRMC ($/MWh) – gas at $7/GJ, no carbon charge	LRMC ($/MWh) – gas at $10/GJ, carbon at $30/t	LRMC ($/MWh) – gas at $13/GJ, carbon at $50/t
Combined cycle gas turbine	50%	95	127	155
	70%	83	115	144
Diesel-fired peaker	5%	613	634	648
Gas-fired peaker	5%	523	569	609
Conventional coal plant	30%	167	193	210
	50%	119	145	163
	70%	98	125	142
	90%	87	113	130
IGCC coal plant with CCS	70%	139	143	145
	90%	121	124	126

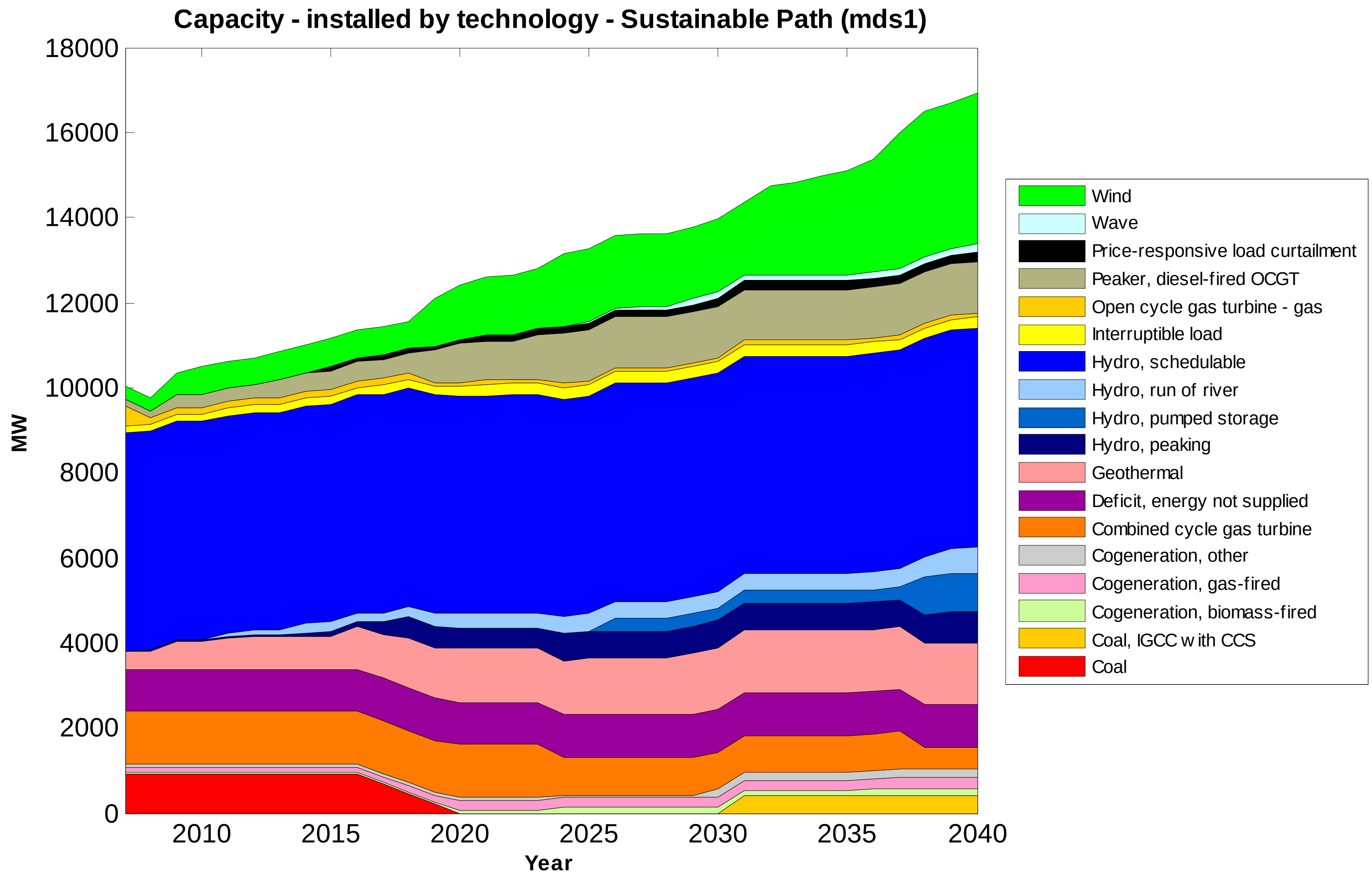
GEM update

- Generation Expansion Model (GEM) used to develop scenarios
- Participants can use GEM to recreate the scenarios and explore variations
- GEM development continues
  - Dr Phil Bishop will discuss recent developments in a later presentation
  - Model and related material downloadable
    http://www.electricitycommission.govt.nz/opdev/modelling/gem/index.html
- Notable changes since October 07 draft GPAs:
  - optimises scenarios over a selection of hydro flow regimes (very dry to very wet) rather than optimising on an averageish year and reoptimising on a dry year
  - more detailed treatment of existing hydro schemes
  - ‘renewable energy constraint’ no longer used
  - more model flexibility used to implement some new scenario features

Results – to 2025 (note scenarios extend to 2040)

Scenario	2008 - 2010	2011 - 2015	2016 - 2020	2021 - 2025
Sustainable Path	New wind and geothermal developments, possibly with diesel- or gas-fired peakers to provide security of supply at North Island peak. Status of HVDC Pole 1 not yet known.	New HVDC Pole 1. Hydro and geothermal development backed by thermal peakers.	Coal-fired units at Huntly close down. Hydro, geothermal and wind development backed by demand-side response.	Stratford Power Station decommissions. Tiwai smelter begins to close down. Hydro and wind development backed by thermal peakers.
SI Surplus		New HVDC Pole 1. Hydro, geothermal and major South Island wind developments, backed by thermal peakers.	Coal-fired units at Huntly shift to dry-year reserve status. Major south island hydro developments.	Coal-fired units at Huntly close down. Wind development backed by more thermal peakers.
Medium Renewables		New HVDC Pole 1. Mixed renewable development backed by thermal peakers.	Coal-fired units at Huntly shift to dry-year reserve. New CCGT built when moratorium lapses. Demand-side backs renewables.	Coal-fired units at Huntly close down. Renewable development continues. More gas plant built, taking a mid-order role.
Demand Side Participation		New HVDC Pole 1. Mixed renewable development backed by thermal peakers.	Geothermal and hydro development. Demand-side takes an important role with advanced metering widespread.	New CCGTs built after thermal moratorium lapses. Demand side continues to develop.
High Gas Discovery		New HVDC Pole 1. Two Huntly units replaced by Rodney CCGT. Demand side has little involvement; thermal peakers used instead.	Relatively little generation development.	Coal-fired units at Huntly close down. More CCGTs built, operating in a semi-baseload role. Some geothermal development.

Sustainable Path



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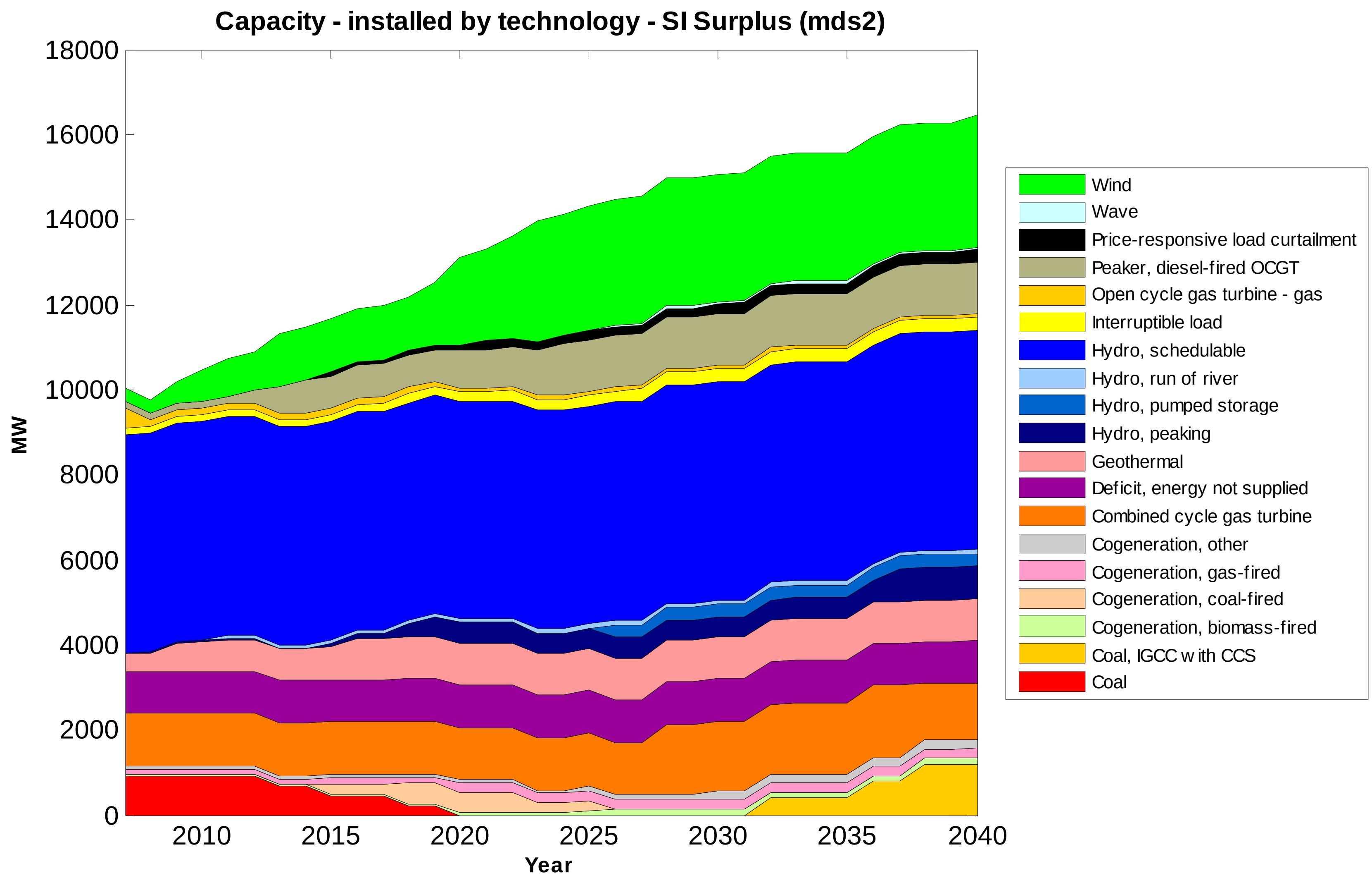
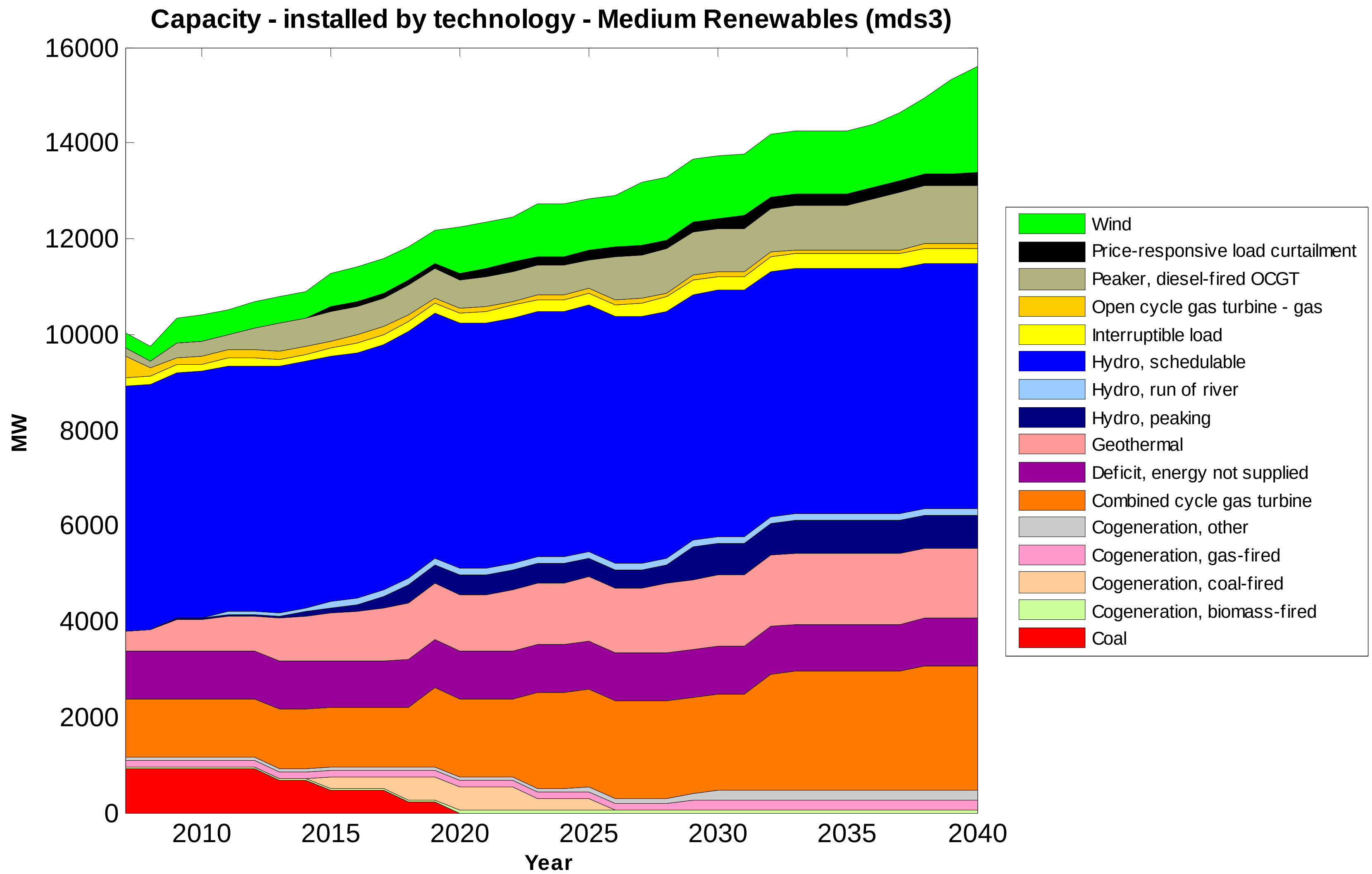
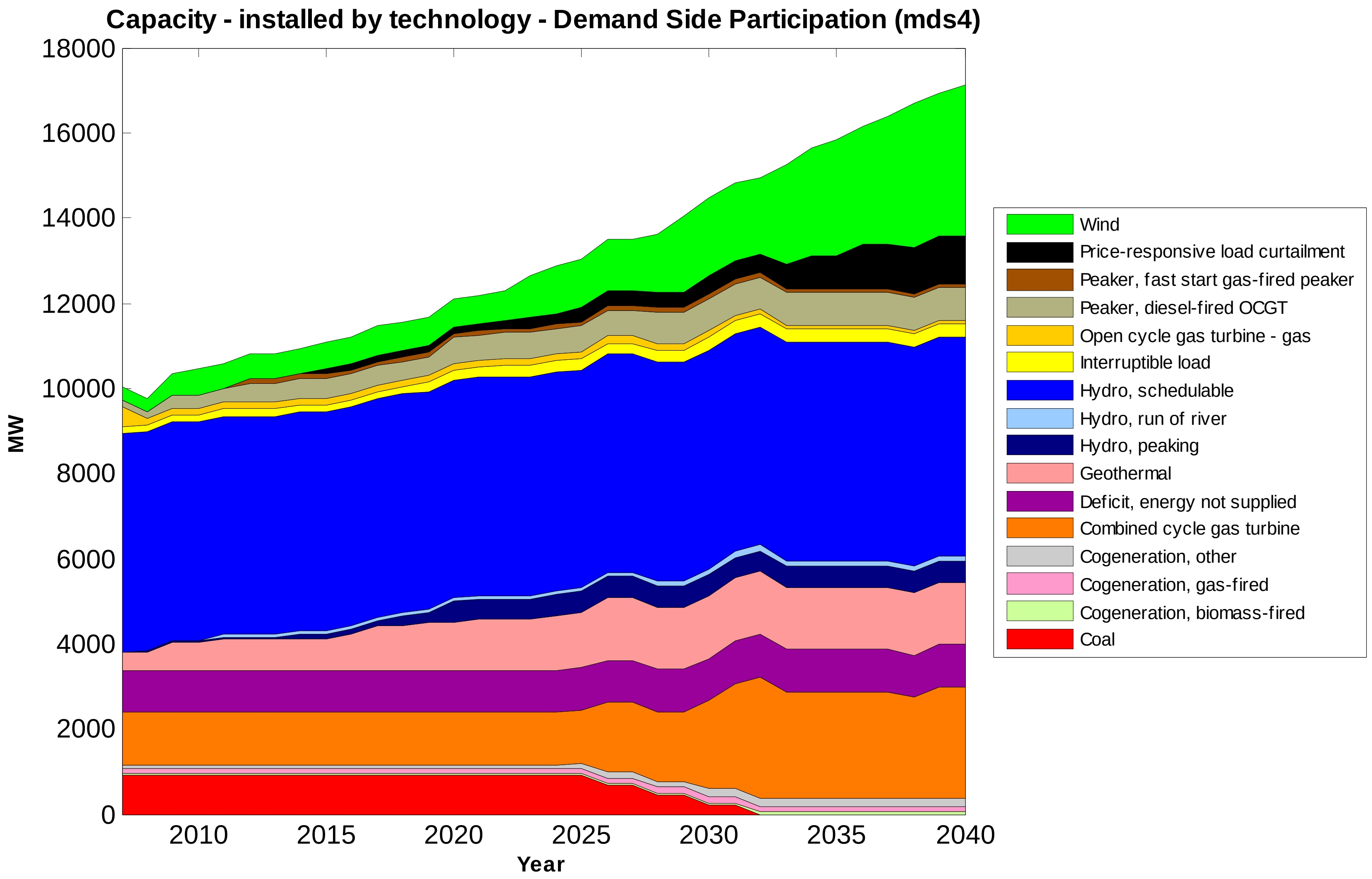
South Island Surplus



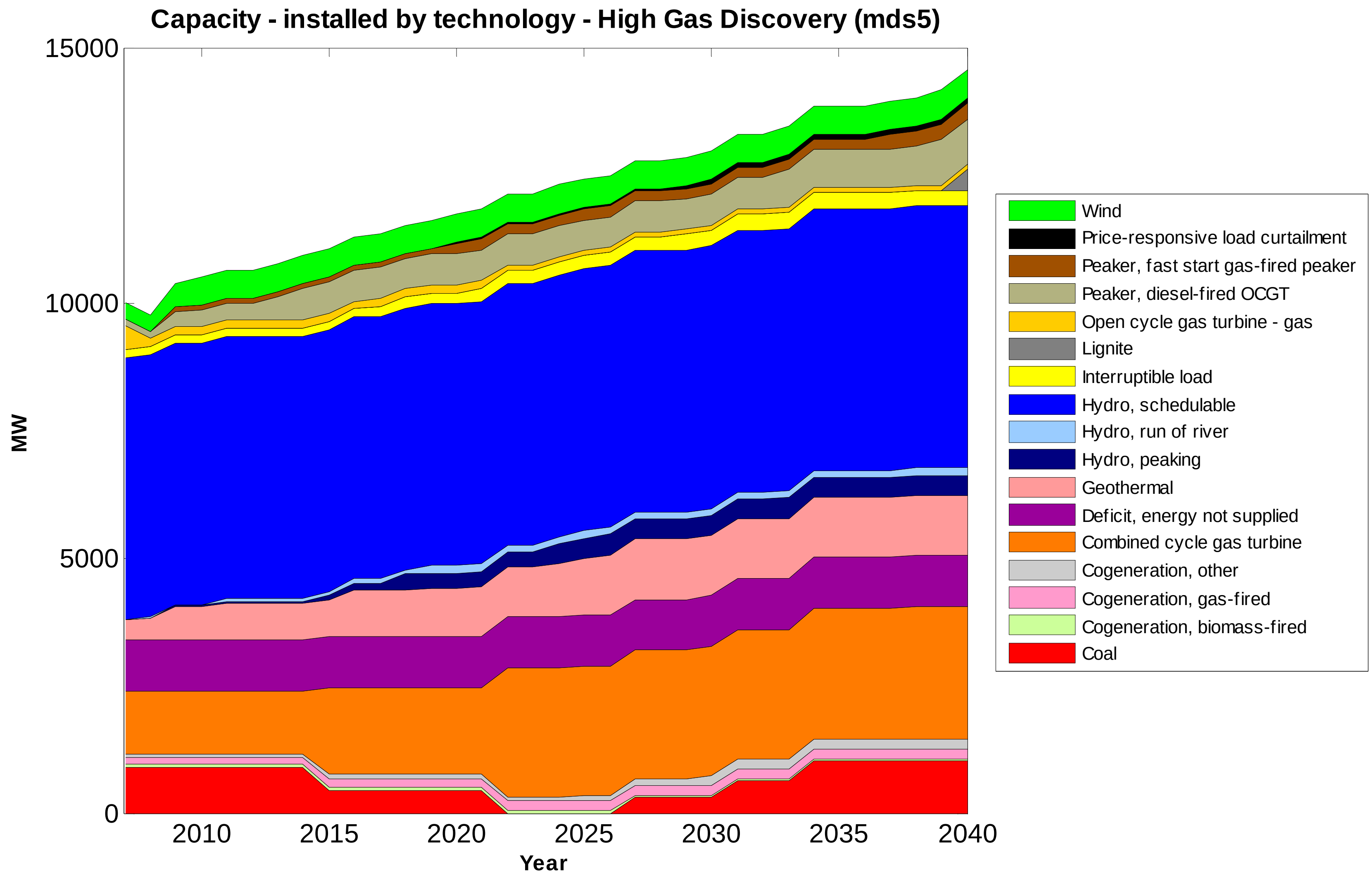
Medium Renewables



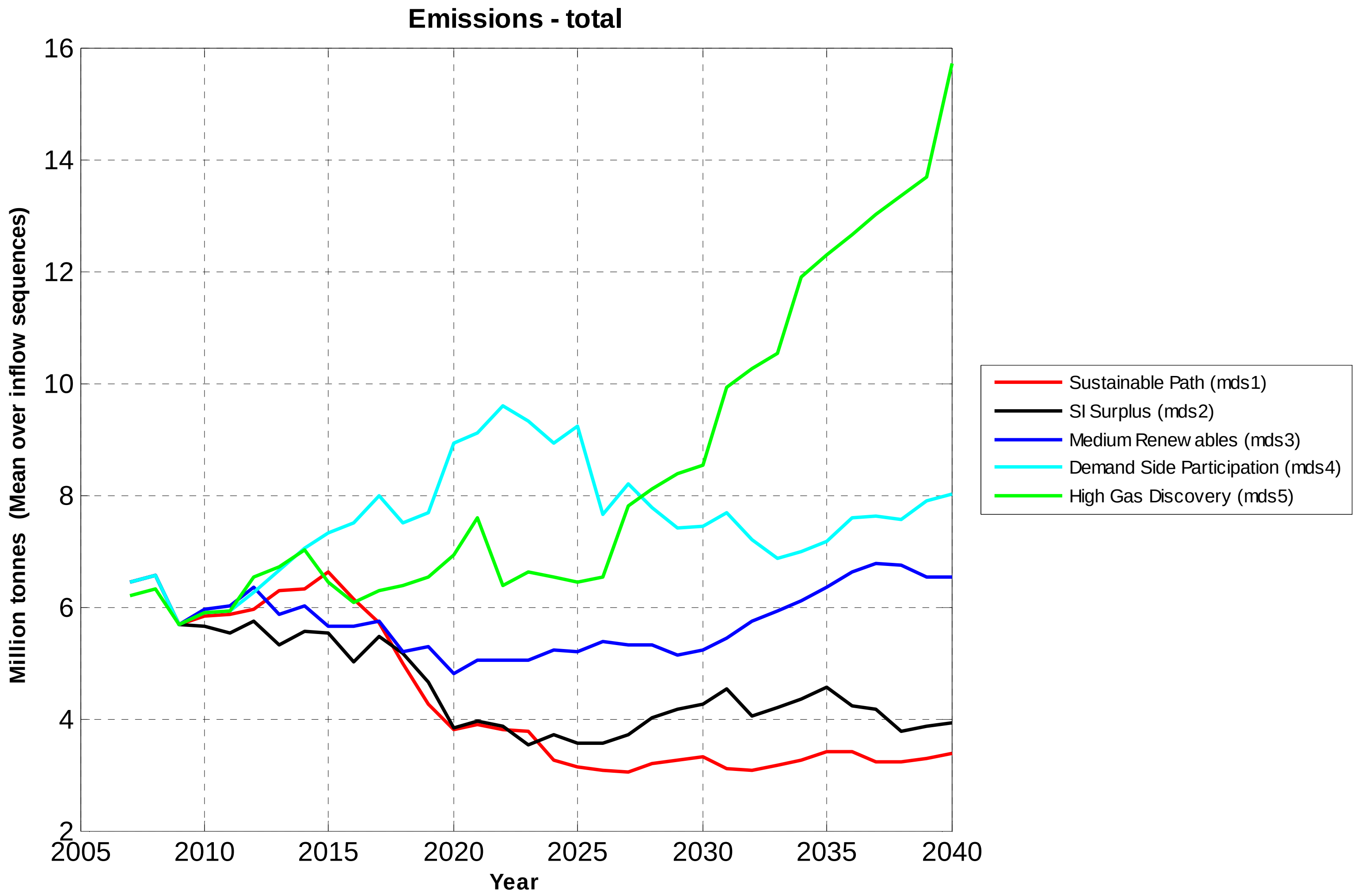
Demand Side Participation



High Gas Discovery



Emissions



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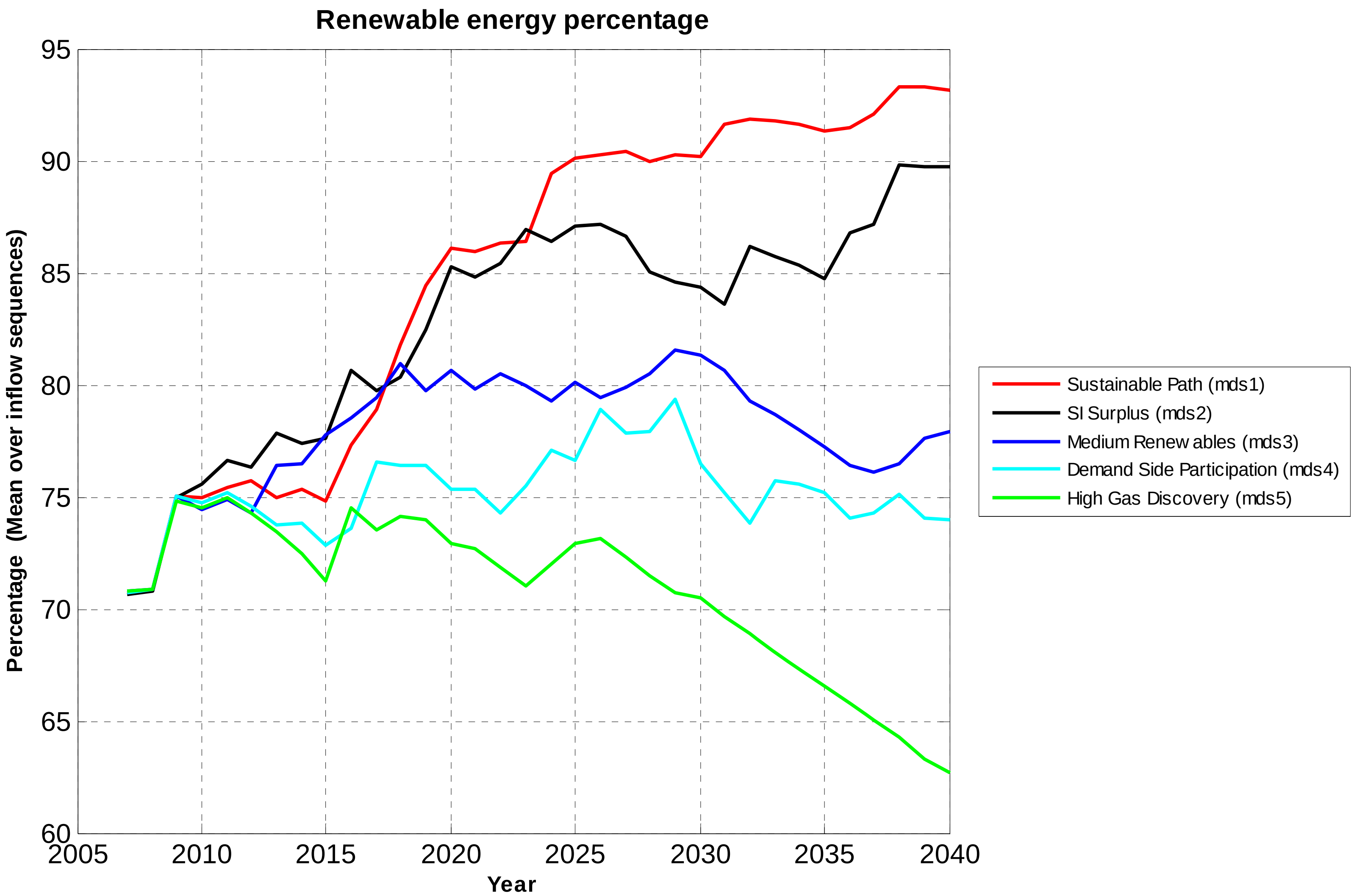
Renewable electricity percentage



Revenue adequate?

- Earlier scenarios were criticised as being revenue inadequate
  - too much generation being built
- We are inspecting the issue
  - Developing ‘statistical projections’ of wholesale price
    - Higher when thermal SRMC are high, when peakers are running frequently, and when capacity margins are low
    - Lower when thermal fuels are cheap, when the market is saturated with renewable baseload, or when capacity margins are high
  - Determining how high prices would have to be to provide revenue adequacy
  - Trying to produce shadow prices in GEM
- Current indications are that the scenarios are revenue-adequate, at least in terms of baseload and mid-order plant
- In fact MDS 1 seems a bit underbuilt (‘statistical projections’ of wholesale price >> LRMC of new generation)
- Not yet clear whether the peaking plant in the scenarios is revenue-adequate under current market structure (doing more work on this)

Ongoing work

- Revise scenarios by end of March
- Take into account feedback from submitters
- Update GEM input data based on TTER work
- Continue developing price forecasting methodologies to test revenue adequacy
- More GEM model development as time permits:
  - co-optimisation of generation and transmission
  - model the effect of hydrological variation on new hydro generation projects
  - model energy requirements at peak time and when wind output is low
  - improve the treatment of the potential of electric vehicles as storage devices
  - revise the constraints on intermittent (esp. wind) generation