

NPRA Q&A cfp 'Technology Forum'2010

Answer Book

**Baltimore, Maryland, USA
10-13 October 2010**

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Crude/Vacuum Distillation & Coking Q&A

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FCC Q&A

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Gasoline Processes Q&A

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Hydroprocessing Q&A

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